THE IMPACTS OF TECHNOLOGY ON

GLOBAL UNCONVENTIONAL GAS SUPPLY

A Thesis

by

EVI YANTY

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

August 2007

Major Subject: Petroleum Engineering

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ABSTRACT

The Impacts of Technology on Global Unconventional Gas Supply. (August 2007)

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As energy supplies from known resources are declining, the development of new energy sources is mandatory. One reasonable source is natural gas from unconventional resources. This study focus on three types of unconventional gas resources: coalbeds, tight sands, and shales. Whereas these resources are abundant, they have largely been overlooked and understudied, especially outside of North America.

New technologies, including those needed to unlock unconventional gas (UCG) resources, have been acknowledged to be the most significant factor in increasing natural gas supply in the United States. This study evaluates advances in critical technology that will most likely increase supply the most.

Advanced technology is one of the main drivers in increasing unconventional natural gas production, as observed in the United States, Canada, and Australia. 3D seismic, horizontal drilling, multilateral completion, water and gel based fracturing, coiled tubing rig, enhanced recovery, and produced water treatments are current important technologies critical in developing unconventional gas resources. More advanced technologies with significant impacts are expected to be available in the next decades.

Fit-to-purpose technology reduces the cost to recover gas from unconventional resources. The better the unconventional gas resources are characterized, the better we can tailor specific technology to recover the gas, and less cost are needed.

Analogy assumption is a good start in deciding which critical technology to be transferred to undeveloped unconventional reservoirs. If the key properties of two unconventional gas basins or formations are more or less similar, it is expected that the impact of certain technology applied in one basin or formation will resemble the impact to the other basin or formation.

DEDICATION

To my parents and family for their love and support.

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CHAPTER I

INTRODUCTION

This chapter is a review of the unconventional gas resources. The description of three types of unconventional gas resources and distribution of unconventional gas resources in North America and other regions are discussed. Based on this review, we present the objectives and scope of study of this thesis.

1.1 Description of Unconventional Gas Resources

Total world energy demand is expected to reach 721.6 Quad BTU in year 2030, a significant increase compared to the 420.7 Quad BTU in year 2003. [1] As energy supplies from known resources are declining, the development of new energy sources is mandatory. One reasonable source of energy is natural gas from unconventional resources.

Unconventional natural gas resources are described as gas accumulations that are difficult to discover, characterize, and commercially produce by existing technology. The common characteristic of the different types of unconventional gas resources is that they contain large quantities of natural gas, but it is usually more difficult to produce this gas as compared to conventional reservoir rocks. These resources are typically located in heterogeneous, extremely complex, and often poorly understood geologic systems.

This thesis follows the style of Society of Petroleum Engineers (SPE) Journal.

Technological advances, attractive natural gas prices, and the need to replace declining conventional reserves will make unconventional gas resources more favorable. Figure 1.1 illustrates the position of unconventional gas resources in the concept of resource triangle.

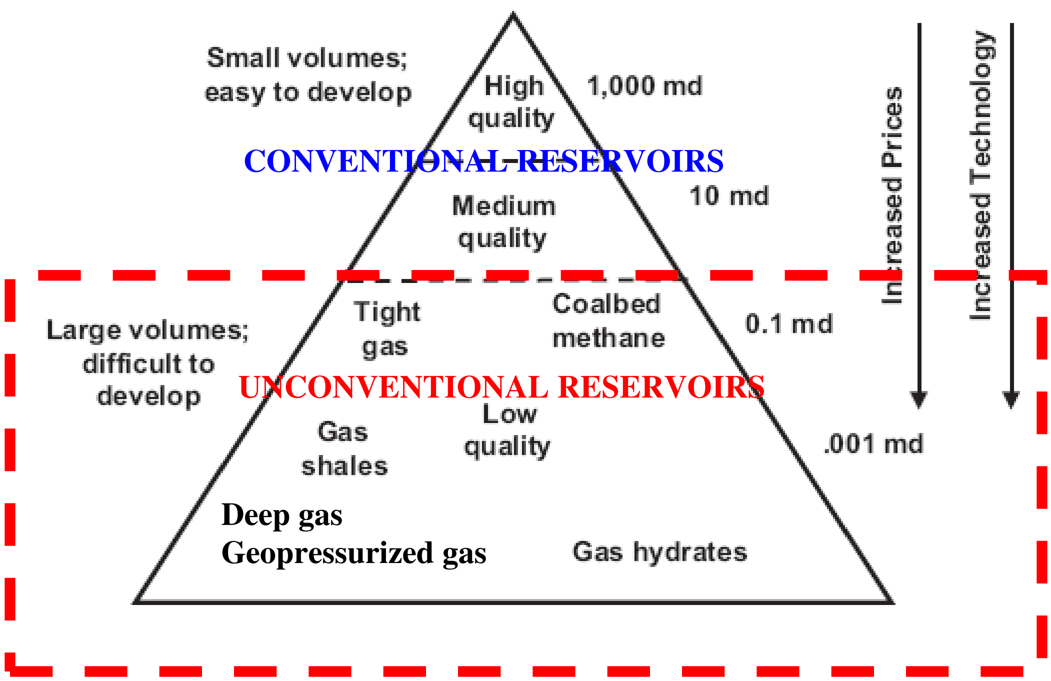


Fig. 1.1—Resource triangle for natural gas [2]

Past studies categorize natural gas from coalbeds, tight sands, shales, hydrates, deep formations, and geopressurized zones as unconventional gas resources. But until today, only natural gas from coalbeds, tight sands, and shales are commercially produced.[3-5] . Moreover, the largest volume of unconventional gas in the U.S. occurs in these three resources. Therefore, in this study unconventional gas resources refer to coalbeds, tight sands, and shales. Gas from deep formations, geopressurized zones, and hydrates are not included because until today we have only very little information and knowledge about them.

1.1.1 Coalbed Methane

Many coal seams also contain natural gas, primarily methane, either within the seam itself or the surrounding rock. Coalbed methane (CBM) is trapped underground, and is generally not released into the atmosphere until coal mining activities unleash it. Historically, CBM has been considered a nuisance in the coal mining industry. As the coal is extracted, the methane contained in the seam usually leaks out into the coal mine itself. This poses a safety threat, as too high a concentration of methane in the mine creates dangerous conditions for coal miners. In the past, the methane that accumulated in a coal mine was intentionally vented into the atmosphere. Today, however, CBM has become a popular unconventional form of natural gas. This methane can be extracted and injected into natural gas pipelines for resale, used as an industrial feedstock, or used for heating and electricity generation.[3, 6]

1.1.2 Tight Gas Sands

Tight gas sands are distinguished from conventional gas sands by their very low permeability. They require production stimulation, usually through hydraulic fracturing, to produce gas at economical rate. Because of their low permeability, the bulk of production from these reservoirs is through narrow natural fractures that act as flow conduits.

The US government issued a political definition of a tight gas reservoir as one in which the expected value of permeability to gas flow would be less than 0.1 md. The definition has been used to determine which wells would receive federal and/or state tax credits for producing gas from tight reservoirs. The advanced definition of tight gas reservoir is "a reservoir that can not be produced at economic flow rates nor recover economic volumes of natural gas unless the well is stimulated by a large hydraulic fracture treatment or produced by use of a horizontal wellbore or multilateral wellbores". [2, 6]

1.1.3 Gas Shales

Natural gas is stored in shale in two major ways:

- As adsorbed gas on kerogen (insoluble organic matter). In this respect, it is similar to natural gas from coals. The adsorbed gas portion ranges between 20% (Barnett Shale) and 85% (Lewis Shale). [7]
- The second component of gas is present as free gas in the matrix porosity and fractures. This component is compressible and in this regard, is similar to conventional gas reservoirs.

Gas shales act both as a source and reservoir rock. This gas is either biogenic, formed by the action of biologic organisms breaking down organic material within the shale, or thermogenic, formed at higher temperatures.

Most gas shales have very low permeability, and production rates are usually quite low, with low recovery factors that are a fraction of conventional reservoirs. The area extent of the deposits and the longevity of shale gas wells compensate for low flow rates. Additionally, shale easily breaks into thin, parallel layers. Thus more advanced gas production techniques are required. to produce gas at economical rate.

1.2 Distribution of Unconventional Gas Resources

More than 25 basins in North America have produced substantial volumes of unconventional gas. Outside of North America, there are more potential basins that may hold substantial volumes of unconventional resources. However, very limited data have been published on unconventional reservoirs outside of North America.

1.2.1 North America

Natural gas from unconventional resources already plays an important role in meeting the energy demand of the United States (US). These resources are particularly attractive to natural gas producers due to their long-lived reserves and stabilizing influence on reserve portfolios. Large accumulations occur throughout the Rockies, in the Appalachians and Midwest, and in the Mid-Continent, as shown in Figure 1.2. [8]

According to Gas Technology Institute (GTI), approximately about 703 Tcf of CBM in-place is available in various basins in the Lower 48 states US, of which recoverable reserves are estimated at 63 Tcf from known resources and 100 Tcf from undiscovered resources. Another 1,045 Tcf CBM in-place is estimated available in Alaska, with expected 57 Tcf recoverable reserves. About 5,000 Tcf of tight gas in-place is estimated exists in the US, with big accumulations in East Texas, Greater Green River, Appalachian, and Piceance basins. The Energy Information Agency (EIA) estimated 254 Tcf of it is technically recoverable. Gas-in-place in shales is estimated between 500 and

600 Tcf, of which 70 Tcf is expected technically recoverable from San Juan, Fort Worth, Michigan, Illinois, and Appalachian basins. [8-10,11,12]

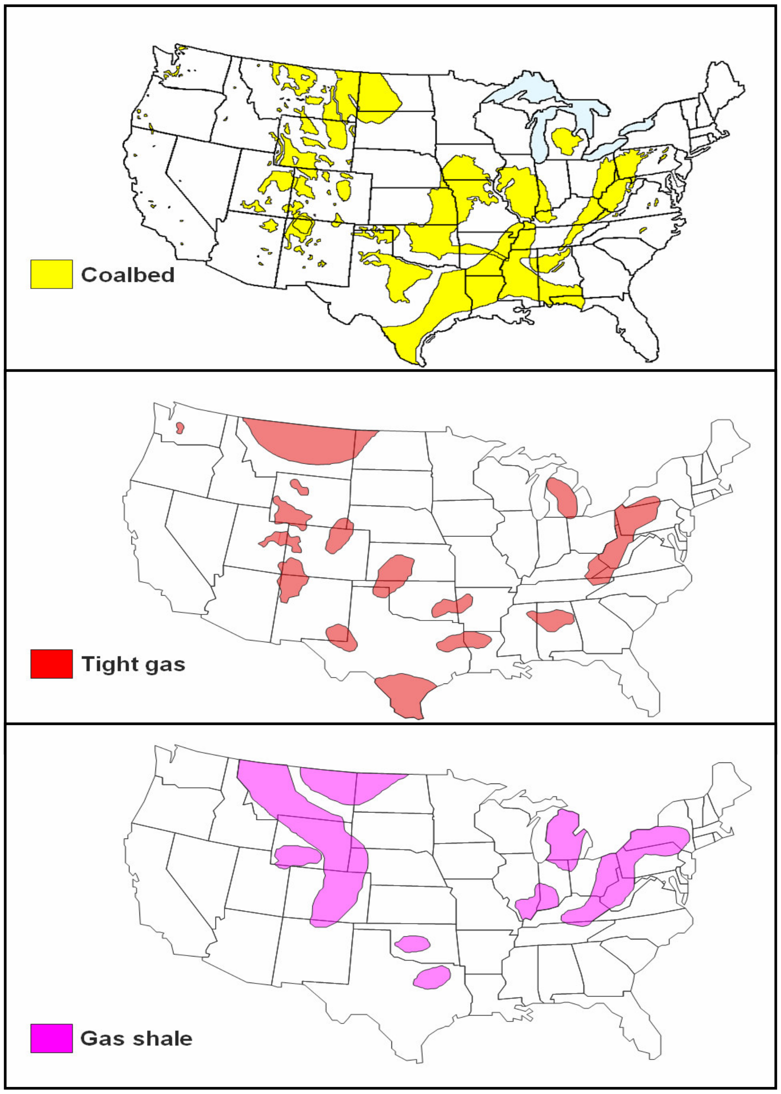


Fig. 1.2—Unconventional gas distribution in US [13,14,15]

Eight of the largest twelve natural gas fields in the US are unconventional gas fields. [16] The largest accumulation, gas fields in the San Juan basin, produced 4.0 Bcfd coalbed methane and tight sand gas in 2004. In the same year, about 40% (7.5 Tcf) of the natural gas production in the US came from unconventional resources, a significant increase compared to 27% (5.2 Tcf) in the year 2000 (Fig. 1.3). All three components of the unconventional gas resources, tight sands (TS), coalbed methane (CBM), and gas shales (GS), have experienced increased production. [16]

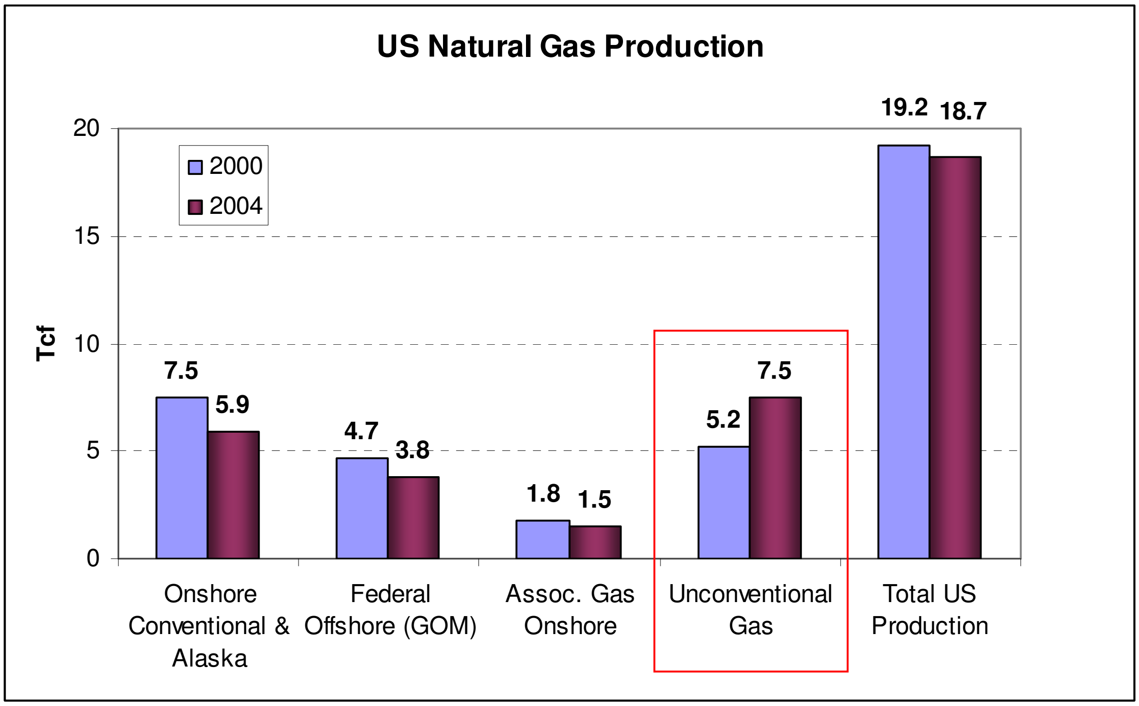


Fig. 1.3—Unconventional gas accounts for 40% of 2004 total US gas production [16]

While the remaining conventional gas in Canada is estimated to be approximately at about 370 Tcf, the potential unconventional gas resources are huge. The latest estimates report about 2,000 to 2,600 Tcf of unconventional gas-in-place is available in Canada. More specifically to resource type, the gas-in-place estimates for coalbed methane are about 539 to 700 Tcf, tight sand gas resources are 500 to 1,500 Tcf, and resources 550 to 860 Tcf for gas from shales. [17, 18]

Currently, Canada produces about 6 Tcf/year natural gas, both conventional and unconventional, mostly from the Western Canadian Sedimentary Basin (WCSB). However, supply from currently known conventional resources is leveling out and is anticipated to decline over the next decade. By 2025, Canada's conventional gas supply is forecast to meet rising domestic demand only. To meet the challenge of domestic demand and maintain the current level of export to the US (50% of total Canadian gas production), it is estimated that about 40% of the gas production would come from unconventional gas. [17, 18]

The first commercial Canadian CBM production was launched in 2001 from the Horseshoe Canyon/Belly River coals of central Alberta. With more than 6,000 CBM wells, production is expected to reach 0.7 Bcf/day this year. [18] Production from tight sands started as early as in the 1990s. Now the Canadian tight gas production has reached several Bcf/day. Gas from organic shales is under evaluation projects.

1.2.2 Worldwide

Outside of North America, Rogner estimated that abundant unconventional gas resources are available (Table 1.1). Almost 4,000 Tcf coalbed methane is estimated available in Former Soviet Union alone. Tight sand reservoirs in Latin America and Caribbean region potentially accumulate about 1,293 Tcf gas. North America leads other regions in potential gas shales.

While the resources are abundant, unconventional gas resources outside of the North America have largely been overlooked and understudied. However, interest has grown during the last decade. Natural gas producers in Venezuela, Australia, China, and

Russia are paying more attention to tight gas reservoirs. Australia has commercially produced CBM, while China and India have seen exploration and early development phase of CBM projects. One of the major challenges in developing worldwide unconventional gas resources is the shortage of expertise in specific technology needed to develop these resources.

Table 1.1 - Rogner's estimate of unconventional gas in place [5]

Region	CBM (Tcf)	GS (Tcf)	TS (Tcf)
North America	3,018.40	3,841.60	1,372
Latin America & Caribbean	39.2	2,116.80	1,293.60
Western Europe	156.8	509.6	352.8
Central & Eastern Europe	117.6	39.2	78.4
Former Soviet Union	3,959.20	627.2	901.6
Middle East & North Africa	0	2,548	823.2
Sub-Saharan Africa	39.2	274.4	784
Central Asia & China	1,215.20	3,528	352.8
Pacific OECD	470.4	2,312.80	705.6
Other Pacific Asia	0	313.6	548.8
South Asia	39.2	0	196
World	9,055.20	16,111.20	7,408.80

Unconventional gas production is most mature in the United States, not because the US is geologically unique, but because of the producers in the US simply have more incentive, experience, and technology to produce unconventional gas. [16] Terasaki and Fujita.[7] suggested a solution to increase worldwide unconventional gas production. They suggested that technical transfer of advanced production technology of unconventional gases from experienced US companies will significantly affect the development of unconventional gas worldwide. This suggestion is reasonable and it has been shown that some technologies work well in different US unconventional gas fields with similar characteristics. [5]

1.3 The Objectives of the Research

This study seeks to identify the appropriate types of technology likely to develop worldwide unconventional gas and to determine the impacts of these technologies on the global unconventional gas supply.

These are the procedure to accomplish the objectives of this study:

(1) Survey the literature and find existing studies, papers, articles, etc. on unconventional gas (UCG) supply and on the technology employed.

(2) Determine technology improvement parameters, most likely to be available mostly for North America.

(3) Characterize the UCG resource base at the lowest possible level (e.g., formation, geological basin).

(4) Determine critical technology advances that will likely increase supply the most and the key resource characteristics that make critical technologies important for specific UCG resource.

(5) Estimate the impact of the most important technologies on the UCG supplies affected.

(6) Extrapolate results from North American studies to the global situation.

1.4 Scope of Study

In this thesis, unconventional gas resources refer to coalbeds, tight sands, and shales.

CHAPTER II

CHARACTERIZATION OF MAJOR UNCONVENTIONAL GAS BASINS

2.1 Coalbed Methane

Important characteristics that determine the methane producibility of coal seams consist of gas content, coal rank and generation, permeability, hydrodynamics, tectonic and structural setting, and depositional setting and coal distribution. These characteristics help us determine which technologies are applicable to recover CBM from certain coal formations or basins. In this sub-chapter we will describe major coal basins in the world and characterize them as much as possible.

2.1.1 United States

Major CBM productions in the United States occur from the Rocky Mountain areas to the Appalachians, plus Alaska (Fig. 2.1). Total CBM resource in US is estimated to be 701 Tcf in Lower 48 states and 1,045 Tcf in Alaska (Table 2.1).

Alaska

Thirteen basins have been identified in Alaska for CBM development. Three of these basins, the western North Slope Basin near Wainwright (northern Alaska), Alaska Peninsula near three Chignik Bay communities (near Anchorage and the southwestern peninsula of Alaska), and the Yukon Flats Basin at Fort Yukon (central Alaska north of Fairbanks), have been identified for potential development to meet the energy needs of rural communities.The coal resource varies in rank from bituminous to lignite, and formed in extensive Cretaceous to Tertiary aged basins throughout the state. Eighteen seams of high-volatile C bituminous coal were identified, with the thickest being 6.5 feet (2 m) and a net coal thickness of 41 feet (12.5 m). [19,20]

Fig. 2.1 — Major coal basins in United States

Appalachian Basin

The Middle and Upper Pennsylvanian coal bearing units of the Alleghany, Conemaugh, and Monongahela groups, as well as the Permian Dunkard Group, all have CBM potential in the Northern Appalachian. The following coal seams were identified as the main targets for CBM: Clarion/Brookville, Kittanning, Freeport, Mahoning, Pittsburgh, Sewickly, and Waynesburg coal groups. These groups are composed of several individual coals seams, with the cumulative thicknesses of the groups being relatively thin at 10 to 19 feet. The depth to the coal groups varies within the basin to as much as 2,000 feet, but the seams that show the greatest CBM potential are often 500 to 1,200 feet. The coals increase in rank eastward in the basin from high volatile bituminous to low volatile bituminous. The coals of the Central Appalachian Basin are older (lower and middle Pennsylvanian) and often thicker than those in the northern part of the basin.

Areas of commercial CBM production in Virginia occur in three coal bearing intervals: the Pocahontas, Less and Norton Formations, with targeted coal seams deeper (1,500 to 2,500 feet) than in the northern portion of the basin

Permeability of Appalachian coals ranges from less than 0.1 md to 10 md. Commercial CBM production within the Appalachian Basin mainly comes from three seams, with average thickness less than 20 ft. Gas content is from 200 - 400 scf/ton. Total CBM cumulative production was 266 Bcf in 2001. Reserve estimates of CBM for the Appalachian Basin range from 60 TCF to as much as 76 TCF. [20]

Table 2.1 – US CBM resource (in-place) per basin, Tcf [21]

Basin	CBM resource (Tcf)
Alaska	1,045
Arkoma	3
Black Warrior	19
C. Appalachian	5
Cherokee/Forest City	7
Greater Green River	314
Gulf Coast	6
Hanna-Carbon	15
Illinois	13
N. Appalachian	61
Piceance	81
Powder River	61
Raton	10
San Juan	78
Uinta	10
Western Washington	12
Wind River	6
Total	1,746

Arkoma - Cherokee Basin

As early as the 1920s, development of gas from the Mulky coal beds of the Cherokee Group was occurring in southeast Kansas. In the 1980s as a result of the Tax

Credit, the exploration for coal bed gas was occurring in the Cherokee Platform. In 1992 there were 230 CBM wells in Kansas; toward the end of 2001 there were 738 CBM wells in the Oklahoma portion of the Cherokee Platform. The Oklahoma wells average 947 feet of depth to top of coal, 27 Mcf per day and 60 barrels of water per day. By 2001, there were 552 CBM wells completed in seven coal seams in the Oklahoma portion of the Arkoma Basin. The wells average 1,421 feet of depth to top of coal and produced between 106 Mcf per day with most of the wells producing less than 20 barrels of water per day. [20]

Black Warrior Basin

The USGS estimates the CBM reserves in the Black Warrior Basin to be approximately 20 TCF with approximately 3.4 TCF technically recoverable. After the first CBM wells were permitted in 1980, CBM production in Alabama steadily increased until 1991, at which time the volume of gas produced nearly doubled the previous year's production. This significant increase in CBM production resulted from an increase in well drilling that started in 1988 and has been attributed to the approaching end of tax incentives. The cumulative production through end of 2001 was 1.3 TCF. A total of 5,600 CBM wells have been drilled in Alabama, with 3,250 still actively producing. [20]

Green River Basin

The Green River Basin is composed of five smaller basins located in portions of Wyoming, Colorado, and Utah. The potential for CBM development in the Green River Basin is from coals in the Upper Cretaceous Rock Springs, Almond, Williams Fork, and

Paleocene Fort Union Formations. There are as many as 30 individual coal seams in some beds with four to eight coal beds more common; individual seams can be as thick as 50 ft thick. The coals grade from sub-bituminous B to high volatile bituminous B with normal cleat development. [20]

Gulf Coast

The potential for CBM development in the Gulf Coast exists in coals from the Upper Cretaceous Navarro Group, Cretaceous Olmos Group, Upper Paleocene/Lower Eocene Wilcox Group, Middle Eocene Claiborne Group, and the Upper Eocene Jackson Group. Warwick et al. identified five CBM prospects across the Gulf Coast region, which have the potential to develop CBM out of the Wilcox Group; the five prospects from east to west are the Oak Hill Prospect, North-Central Louisiana Prospect, West Sabine Prospect, East-Central Texas Prospect, and the South Texas Play. The USGS report indicates that the resources are between 4 and 8 TCF, but the amount of recoverable gas is currently unknown.[22]

Illinois Basin

There have been numerous CBM test wells drilled in Illinois, Indiana, and Kentucky, but currently there is limited commercial production. The test wells in Indiana have been drilled in high volatile bituminous coals. In addition to these wells, other gas production wells in Kentucky and Illinois have been producing from coal seams, but are not identified as CBM wells.[20]

Powder River Basin

The permeability of coals in Powder River basin ranges from 0.1 md up to 20 md. The gas content is low at average of 50 scf/ton The development of CBM in this basin started in the late 1980s within the Wyoming portion of the basin and began to slowly expand into the early 1990s. Since early 1999, the number of wells within the Wyoming portion of the basin has increased ten fold from approximately 700 producing wells to nearly 9,000 producing CBM wells in early 2002. CBM gas production has seen similar increases from approximately 3.5 MMcf per day in 1999 to over 25 MMcf per day in early 2002. Most production came from single coal seam completions. The USGS has estimated the total reserves at 30 TCF. [20]

Raton Basin

The Raton Basin is located in southeastern Colorado and extends into northeastern New Mexico. This multi seams (4-14) basin contains Upper Cretaceous and Paleocene coal bearing rocks in the Vermejo and Raton formations with the potential for CBM development. The Vermejo formation has individual coal seams as thick as 14 ft with cumulative coal thickness from 5 to 35 ft; the Raton formation has net coal thickness from 10 to 120 ft. The coals in the Vermejo formation vary from high-volatile C bituminous along the basin margins to low volatile bituminous in the basins.

The methane potential of these coal beds has been identified because of coal mining activities in the Morley mine area where coal-gas relief activities have been. About 286 BCF of coalbed methane (CBM) and 387 MMBW have been produced from more than 1,760 wells in the Raton Basin portion of the province since the start of commercial CBM production in 1984. In 1995, the U.S. Geological Survey estimated mean undiscovered CBM resources at 1.78 trillion cubic feet; the province is currently being reassessed. Production has expanded outside the play boundaries defined in the 1995 assessment, and boundaries in the reassessment include the entire extent of the Upper Cretaceous Vermejo and overlying Cretaceous-Tertiary Raton Formations. [23, 24]

San Juan Basin

The Cretaceous age rocks of the San Juan Basin, in particular the Fruitland and Menefee Formations, contain substantial coal beds which have been developed for commercial use. The individual coal seams within the Fruitland Formation vary in thickness with a maximum of nearly 40 feet, while averages in most of the basin are closer to 6 to 9 feet; net thickness can be as great as 100 feet. The Menefee coals are thinner, discontinuous, and more dispersed than those in the Fruitland and are found deeper in the section approximately 6,500 feet, compared to approximately 4,000 feet for the Fruitland. The Fruitland coals rank 3-18 from sub bituminous C to medium-volatile bituminous from southwest to northeast across the basin. A similar trend was identified in the Menefee coals, but the Menefee coals rank higher.

The methane gas in the formations across this basin has been identified as an economic resource for nearly 100 years, and has been exploited since the 1940s and 1950s. San Juan basin is world’s largest CBM field with annual production of 0.9 TCF and cumulative production of approximately 9 TCF (2001). Permeability ranges from less than 0.1 md to 80 md. Good thickness (average above 30 ft, up to 120 ft) and high gas content (200 to 1,000 scf/ton) makes San Juan successful. [20]

Uinta Basin and East-Central Coal Bed Methane Areas

Permeability range of coals in this basin ranges from <0.1 md to 10 md. The maximum gas content is 300 scf/ton. The methane produced in the active fields of the Uinta Basin is from two formations, the coalbearing and associated sands of the Blackhawk formation and the Ferron Sandstone Member of the Mancos Shale. Significant production began in 1992 and is continuing to rise today. There are currently approximately 200 CBM wells within the Uinta Basin with more wells expected. The estimated total recoverable CBM reserves from this area are approximately 10 TCF. In 2001, the Utah counties of Carbon and Emery had 72 million and 7.3 million MCF of production, respectively. [20]

Wind River Basin

The Wind River Basin is located in central Wyoming just to the southeast of the Powder River Basin. The Wind River Basin has the potential for significant CBM development from the Upper Cretaceous Mesaverde and Meeteetse Formations, as well as the Paleocene Fort Union Formation. The coal beds within each of these formations varies with the Mesaverde having cumulative thicknesses as high as 100 ft, while the Meeteetse coals cumulative thicknesses are generally less than 20 ft (Johnson and Rice, 1995a). The Fort Union Formation, which is economically developed for CBM in the nearby Powder River basin, has cumulative thicknesses as high as 100 ft in the western and central portions of the basin. The estimated CBM reserves within the Mesaverde coal beds of the Wind River Basin range between 2.2 TCF to 6 TCF. [25]

2.1.2 Canada

In Canada, the term natural gas in coal (NGC) is more widely used than coalbed methane (CBM). Canadian Society for Unconventional Gas (CSUG) estimates there is about 182 to 553 Tcf of original gas-in-place associated with coalbeds. About 75% of the NGC is in Alberta province, and the rest is distributed in British Columbia and East Coast provinces. The major coal plays are pooled in the Western Canadian Sedimentary Basin (WCSB) in British Columbia and Alberta. The major WCSB coals are Horseshoe Canyon, Belly River, Mannville, and Ardley. Kootenay coals and Luscar coals are smaller plays of WCSB in Alberta Foothills area. In the eastern Canada, Stellarton and Cumberland sub-basins are estimated to have 500 Bcf and 1 Tcf CBM in-place. Table 2.2 lists the estimate of CBM in-place in Canada provinces, Fig. 2.2 maps the potential of CBM areas in Canada with the estimate of CBM in-place, Fig. 2.3 illustrates the stratigraphy of WCSB coals.

Table 2.2 – Resource estimates of NGC/CBM in Canada [17]

Area	Min Gas-in-Place (Tcf)	Max Gas-in-Place (Tcf)
British Columbia Foothills	40	119
Alberta Foothills	20	60
Alberta Plains	115	352
East Coast	7	22
Total Canada	182	553

Coal in Canada usually occurs as thinner seams and less permeable compare to the coal in the U.S. In the 1980s, when commercial CBM production began in the U.S., CBM tests were conducted in existing and new wells in Canada with no commercial success. In 2000, a joint venture between PanCanadian Petroleum (now EnCana) and MGV Energy Inc. (now Quicksilver Resources Canada) began a large CBM exploration program in Alberta. They established Canada's first significant commercial CBM production in late 2001 from the Horseshoe Canyon coals. [26]

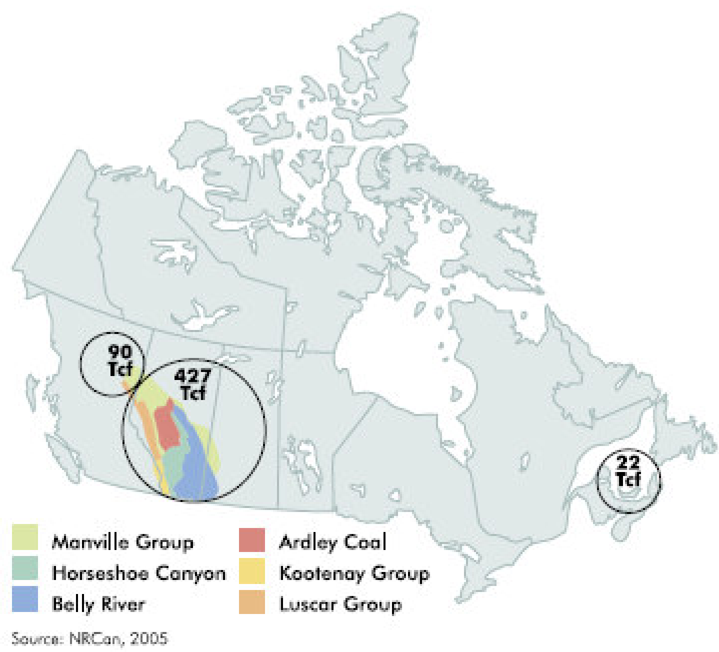


Fig. 2.2 — CBM potential area in Canada and estimated gas-in place [18]

By the end of 2005, many CBM wells had been drilled into the shallow (656 ft - 2,132 ft depth), underpressured Horseshoe Canyon coals, partly because they produce little or no water. The wells target 10 to 20 thin seams of coals, about 1 ft to 10 ft each. Horseshoe Canyon coals have relatively low gas contents, but with favourable cleating/fracturing. Horseshoe Canyon coals extent as far as 11,000 square miles. The estimates ultimate CBM production from Horseshoe Canyon coals is about 73 Bcf from 5,400 wells, while the estimate of gas-in-place in Horseshoe Canyon coals is about 30 to 70 Tcf. By the end of 2006 the production rate had reached 450 MMcf/day. [17, 26, 9]

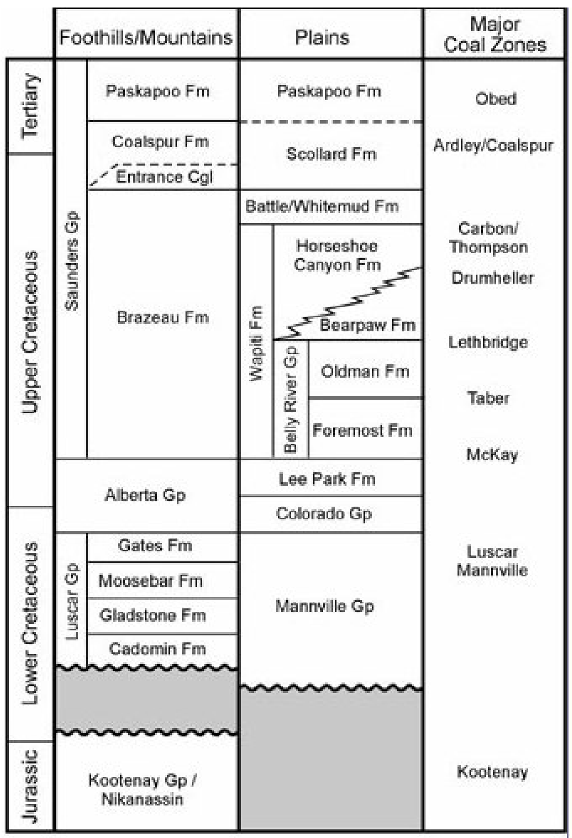


Fig. 2.3 — Stratigraphy of Western Canadian Sedimentary Basin coals [27]

The Mannville formation, with over 260 Tcf of gas resource, is the most abundant CBM resource in Canada. The Mannville coals are deeper than the Horseshoe Canyon and Ardley coals (over 1,000 meters), thus the coal ranks are higher and retain more methane. Study showed methane recovery from Mannville coals most often include some dewatering of saline water to establish commercial gas rates, which adds to the cost of drilling and water disposal. First commercial projects are underway and horizontal wells are promising. [17, 26, 9]

The Ardley coals, estimated with 57 Tcf CBM in-place, are found at depth range 350 to 700 m. The Ardley coals, moderate in gas content, are thick (49 ft to 82 ft) and widespread. There is commercial CBM promise in Ardley coals, but some potential for water production are present which might include usable water. Water studies are in progress to develop guidelines for efficiently recovering Ardley CBM. The Kootenay and Luscar coals have high gas content and are under evaluation projects. [17, 27]

Stellarton coals, estimated to contain 500 Bcf of CBM in-place. These are thin coals 3 ft to 10 ft in thickness, buried in 1,313 ft to 3,937 ft deep. Test on Stellarton coals shows gas content of 330 scf/ton. The Cumberland coal seams are found at depth between 2,000 ft to 8,000 ft. More than 1 Tcf of CBM is estimated in the Cumberland coals. Table 2.3 summarizes the major Canadian coal plays.

Table 2.3 – Summary of the major coals plays in Canada [26, 17]

Formation/ Play	Age	Coal Rank	Depth (ft)	Thick (ft)	Seams	Gas Content (scf/ton)	Perm. (md)	Water
Ardley	Tertiary	Hi volatile bituminous	1,150 - 2,300	49-82	4-18	70 - 120	1 - 5	saline& ground
Horseshoe Canyon	Upper Cretaceous	sub-bituminous	656 - 2,132	1-20	1-25	70 - 140	1 - 15	"dry"
Manville	Lower Cretaceous	Hi volatile bituminous	3,300 – 10,000	> 80	6	200 - 530	1 - 6	saline
Mist Mountain	Jurrasic-Cretaceous	Hi volatile bituminous - semiAnthracite	650 – 8,200	> 50	13	280 - 700	1 - 5	saline
Stellarton	Westphalian	Hi to Med volatile bituminous	1,313 - 3,937	3 - 10		100 - 300		saline
Cumberland	Carboniferous / Westphalian	Hi to Med volatile bituminous	2,000 - 8,000	1-10		100 - 300		saline

2.1.3 Australia

With coal deposits in 30 basins, Australia ranks as the fourth largest coal producer in the world. Currently, it is also the most advanced coalbed methane commercial producer outside of North America. Natural gas from coal beds are also named coalseam methane (CSM), coalseam gas (CSG), and coalmine methane (CMM).

The Australian Gas Association estimates total coalbed methane resource of Australia is about 220 Tcf. As seen in Fig. 2.4, Bowen-Surat Basins are estimated to have proven and probable (2P) reserves at about 7 Tcf, and other basins contain less than 1 Tcf each. [28]

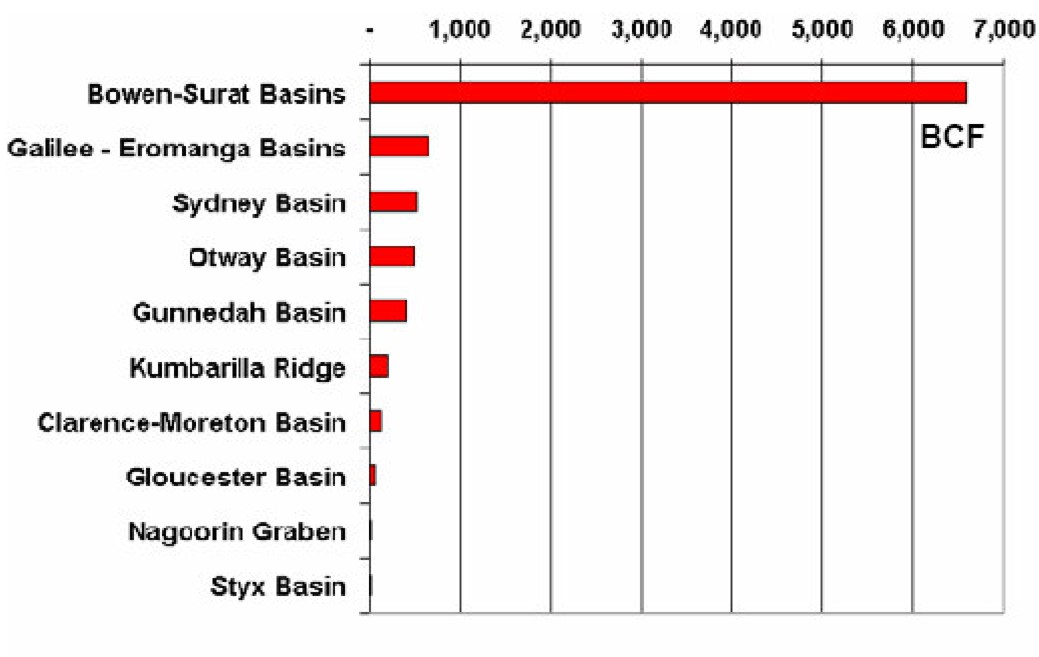


Fig. 2.4 — Estimated 2P reserves of CBM basins in Australia. [28]

The commercial coalbed methane production started in 1996 in the form of CMM, gas associated with coal mining operations. Until today the majority of CBM production activities are in Bowen and Surat basins, followed by Sydney basin. In 2004 the production rate per well was about 400 Mcf/day. In the past 2 years coal bed methane drilling activities have increased significantly, about 100 wells annually, and push the production into 500 MMscf/day/well. The Berwndale well in Surat basin top the highest production rate at 2.3 MMcf/day (see Fig. 2.5). [28, 29]

Bowen-Surat basin has 4 major coal deposits: Baralaba, Walloon Formation, Bandanna, and Moranbah. Baralaba Coal is thickly developed coal with seams up to 8 m (20 ft) thick, has high gas contents ranging from 9-25 m^3/tonne (318 – 883 ft^3/tonne), and has low permeability. The Walloon Formation coals are low rank coal with vitrinate reflectance values 0.44 – 0.56. The Jurassic coals in Surat basin is deposited in shallower depth compare to coals in Bowen basin. The gas content is also lower at about 3 - 13 m^3/tonne. Sydney Permian coals are deposited in depth between 300 – 900 m, with gas content around 8 - 19 m^3/tonne. [28, 29]

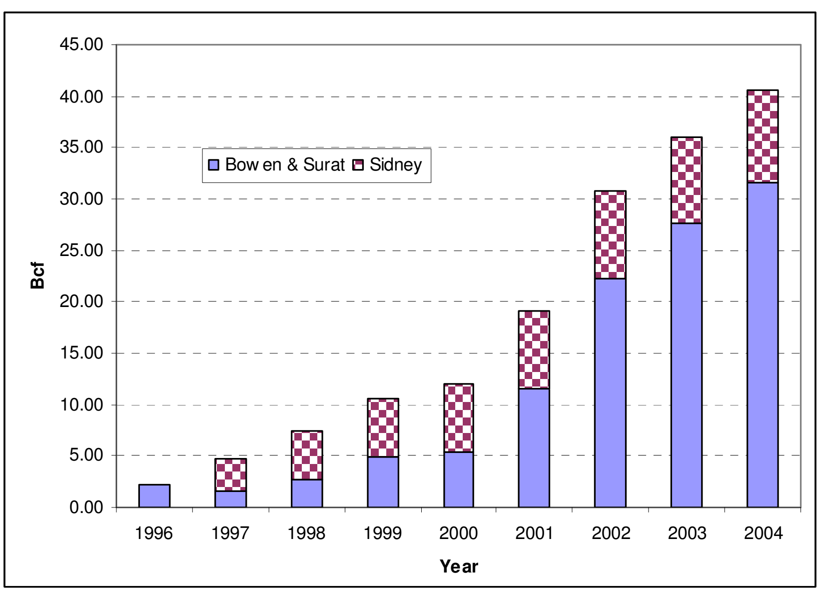


Fig. 2.5 — Growth of Australia CBM production. [30]

2.1.4 China

As the country with the coal reserves as much as 1.2 billion tons, China is estimated to have very large CBM resources. China Coal Information Network estimate the resource at about 800 Tcf, while more IHS Energy estimates 1,200 Tcf. [28, 31] Major coal basins in China are Shanxi basin, Ordos basin, Ningwu basin, Qinshui basin, Bohai Gulf basin, Hefei basin, Erlian basin, and Junggar basin. Most CBM projects in China are in exploration or initial development phases. Since 1990, more than 30 coal bearing areas in China have undergone coalbed methane exploration drilling with a total of 150 surface bore-hole wells for exploration and trial extraction completed, obtaining a batch of coalbed methane reservoir exploration/testing parameters and productive parameters. While in coal bearing areas in Liulin and Jincheng in Shanxi Province, Dacheng in Hebei Province and Tiefa in Liaoning Province, coalbed methane gas flow of industrial scale has been obtained. Until year 2005, more than 500 CBM wells have been drilled. In 2005 alone, there were 330 CBM wells completed, more than the total of the previous decade.[28,31]

2.1.5 India

About 99% of the coal reserves of India deposited in Gondwana coal groups and the rest within the Tertiary basins. The first CBM well was drilled into the Permian Lower Gondwana coals in Jharia basin in 1997. Previous study by Mandal and Ghosh compare the coal basins in India according to the CBM producibility criteria and suggest the rank of potential CBM basins as in Table 2.4.

Table 2.4 – Rank of potential CBM basins in India [32]

BASIN / CRITERION	JHARIA	RANIGANJ	EAST BOKARO	NORTH KARAN-PURA	SOUTH KARAN-PURA	RAJMAHAL	PENCH-KANHAN	PRANHITA-GODAVARI
PROSPECTIVE AREA	3	2	4	3	6	5	2	1
COAL RESOURCES (BTM)	1	2	5	4	6	4	7	1
MAXIMUM DEPTH	3	2	1	2	-	3	4	2
NUMBER OF COAL SEAMS	1	3	2	4	3	5	5	3
TOTAL COAL THICKNESS	3	5	1	4	5	2	6	5
MAXIMUM COAL THICKNESS	4	3	2	1	5	4	6	4.5
COAL RANK	1	4	2	6	3	7	5	6
MAXIMUM GAS CONTENT	1	3	2	4	-	5	3	7
MINIMUM ESTIMATED GAS-IN-PLACE	-	-	-	-	-	-	-	-
NUMBER OF CBM DST	-	-	-	-	-	-	-	-
VITRINITE %	1	2	4	5	3	3	5	8
ASH%	4	1	2	5	3	6	1	7
NO. OF WELLS DRILLED	1	2	3	3	3	3	3	3
RANK	2.08	2.6	2.5	3.72	4.1	4.27	4.27	4.31
PRORITISATION	1	3	2	4	5	6	7	8

Until early 2006 an India E&P company has drilled ten CBM production test wells Soghapur block in Central India. They estimated 3.65 Tcf CBM is in Soghapur fields. They applied air drilling technology and hydrofracturing to the CBM wells. Dewatering and production from the test wells were ongoing by April 2006 to establish producibility rate. [33]

2.1.6 Indonesia

Indonesia is ranked 7th in worldwide coal reserves. Most of the coals in Indonesia is low rank bituminous. The Indonesian Ministry of Energy and Mineral Resources reports an estimate of 350 to 400 Tcf CBM in-place is deposited in Sumatera and Kalimantan basins. In 2005 an exploration CBM well was drilled in South Sumatera basin, followed by four more wells. Now the wells are under dewatering phase, with estimate reserve of 1 – 2 Tcf.

2.1.7 Russia

Russia has the 5th largest coal reserves in the world. Moscow State Mining University estimates the total Russian CBM resource at about 1730 Tcf (49 Tcm), accumulated in several basins as in following Table 2.5 . The coals in Pechora basin is identified to have the highest methane content at about 292 to 380 m^3/m^2. [9, 28]

Table 2.5 – Russian major CBM basins and estimates of in-place methane [9, 28]

Basin	Gas in-place (Tcm)
Kuzbass	13.085
Pechora	1.942
Eastern Donbass	0.097
South Yakutia	0.92
Ziryank	.099
Tunguska	20.0
Lensk	6.0
Taymir	5.5

2.1.8 Europe

CBM exploration activities began in Europe in the late 1990s. IHS Energy reported that in United Kingdom about 120 Bcf of reserves has been discovered from 15 fields. Upper Silesian Coal basin in Poland is estimated to have more than 1.0 Tcf of CBM. Petrosani coal basin in Romania is estimated to deposit significant CBM from its Oligocene-Miocene brown coal. This potential coals contains up to 18 seams (average 22m thickness) with a cumulative thickness up to 50 m at depth 300 – 1,000 m. [28]

2.1.9 Latin America

In 1998 to 2004, eight CBM wells were drilled in the northern part of Cesar basin of Colombia. About 10 Bcf of gas has been discovered in Patilla field. In Argentina a 600m CBM exploration well was drilled in the Claromeco basin. This well produces much water and not considered commercial. Arauco basin of Chile is estimated to have significant CBM potential in its shallow thick, which has better gas content than Powder River basin. [28]

2.2 Tight Sand Gas

The 2005 Energy Resource report of Germany Federal Institute for Geosciences and Natural Resource (BGR) delivered an estimate of worldwide tight gas potential resources be about 3,177 Tcf (90 Tcm). About 45% of worldwide tight gas is accumulated in Former Soviet Unions, 14.7% in the Middle East, 14.1% in North America, and for the rest is distributed in other parts of the world including East and

South Asia (Table 2.6). Exploitation of gas from tight sands is most advanced in the United States, with average production rate at 3.2 Tcf/year. [34]

Similar to the case of coal beds, studies and field experiments suggest key characteristics controlling gas production from tight sands as follow [2]:

- stratigraphy and structure;
- porosity and permeability; and
- mechanical properties.

Table 2.6 – World distribution of tight gas potential [34]

Country / Region	Potential (Tcf)	Percentage
Former Soviet Union	1,445.54	45.5%
Middle East	467.02	14.7%
North America	447.96	14.1%
East and South Asia	311.35	9.8%
Africa	174.74	5.5%
Latin America	149.32	4.7%
West Europe	133.43	4.2%
Australia/Oceania	38.12	1.2%
East Europe	9.53	0.3%
World	**3,177.00**	

2.2.1 United States

Major tight gas accumulations in US are located in East Texas (South Texas trend), Appalachian, the Rocky Mountain, Permian, Piceance, and Green River basins. About 50% of US tight gas production (3.2 Tcf/year) comes from East Texas (South Texas trend), followed by Rocky Mountain region, and Permian and Anadarko basins. Less than 2% comes from the Appalachian basin. Fig. 2.6 shows the map of major US tight sand basins and Table 2.7 summarize the properties of the US major tight sand reservoirs. [18, 35, 36]

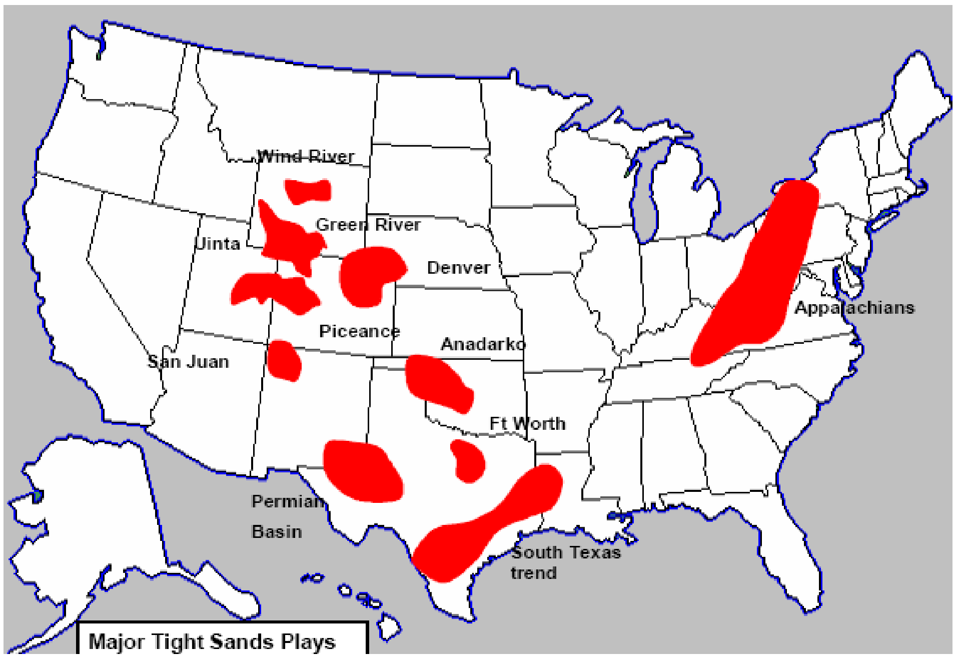


Fig. 2.6 — Major tight sand basins in United States [16]

Table 2.7 – Reservoir properties of major productive tight sands in US [37]

Basin/Play	Age	Avrg EUR (MMcf/well)	Depth (ft)	Porosity %	Permeability (md)	Net Pay (ft)	Depositional System
Appalachia							
Clinton-Medina	Siluian	80-275	2,500-7,000	2-16	0.03-0.6	9-63	Deltaic
Berea	Mississippian	350-460	1,200-6,000	4-17	> 0.1	17-40	Shelf
East TX – North LA							
Cotton Valley	Jurassic to Cretaceous	1,000-2,500	7,000-11,000	6-11	0.015-0.043	50-200	Barrier-Strandplain
Travis Peak	Cretaceous	1,500-2,000	6,000-10,000	5-17	0.0004-0.08	30-90	Fluvial
Maveric							
Olmos	Cretaceous	400-750	3,000-6,000	6-16	0.034-0.072	50	Shelf
TX Gulf Coast							
Wilcox	Paleocene to Eocene	3,000-3,500	9,000-15,000	12-25	0.0003-0.05	10-100	Deltaic
Vicksburg	Oligocene	2,000-3,000	6,000-16,000	3-22	0.035-0.092	80	Deltaic

Table 2.7 – Continued

Basin/Play	Age	Avrg EUR (MMcf/well)	Depth (ft)	Porosity %	Permeability (md)	Net Pay (ft)	Depositional System
Fort Worth							
Davis	Pennsylvanian	200-1,900	3,000-5,000	2-9	0.021-0.31	40-65	Deltaic
Anadarko							
Granite Wash	Pennsylvanian	1,500	6,500-11,500	4-12	0.0009-1.4	10-60	Fan Delta
Red Fork	Pennsylvanian	2,200-8,800	9,000-13,000	1-18	0.1-20	7-200	Deltaic
Cleveland	Pennsylvanian	1,000	5,500-12,000	3-14	0.001-20	6-55	Deltaic
Permian							
Morrow	Pennsylvanian	2,800	11,500-14,700	3-17	0.07	20-100	Barrier-Strandplain
Abo	Permian	511	3,300-5,200	6-80	0.01-0.19	6-80	Fluvial
Val Verde							
Canyon	Pennsylvanian to Permian	730	3,000-6,000	2-15	0.001-0.052	20-300	Slope and Basin
San Juan							
Dakota	Cretaceous	1,630	7,000-8,700	2-16	0.024-0.077	10-110	Barrier-Strandplain
Mesaverde	Cretaceous	500	5,400-6,000	8-9	0.021-0.073	10-250	Barrier-Strandplain
Charca	Cretaceous	565	1,600-3,400	11	0.038	NA	Barrier-Strandplain
Pictured Cliffs	Cretaceous	830	2,500-3,500	10	0.003-0.02	30-50	Barrier-Strandplain
Denver							
J Sandstone	Cretaceous	740	7,600-8,400	8-12	0.005-0.05	4-58	Deltaic
Piceance							
Dakota	Cretaceous	650	2,000-9,000	7-10	0.02-0.05	25-40	Barrier-Strandplain
Mancos B	Cretaceous	250-1,500	3,400-3,600	9.5	0.01-0.08	30-250	Shelf
Mesaverde	Cretaceous	563	2,000-4,000	2.6-22	0.0002-0.08	16-70	Barrier-Strandplain
Green River							
Frontier	Cretaceous	2,370	5,000-20,000	2-20	0.006-0.07	9-90	Barrier-Strandplain
Mesaverde Gp.	Cretaceous	2,850	1,300-15,500	1-10	0.002-0.037	14-18	Barrier-Strandplain
Wind River							
Frontier	Cretaceous	NA	7,600-9,700	8-17	0.034	60	Barrier-Strandplain

2.2.2 Canada

Initial Canadian unconventional activity was dominated in the late 1990s by infill drilling in the shallow gas play of southeast Alberta and southwest Saskatchewan and the deep basin of the WCSB. Fig. 2.7 shows potential tight accumulations in Canada and estimated gas-in-place. Despite the lack of significant fiscal incentives and any specific definition of "tight gas," increased recovery by infill drilling has boosted current tight gas production to several billion cubic feet per day. More recently, advances in horizontal drilling and completion technology have led to the development of tight limestones in northeast British Columbia (B.C.). [38, 18]

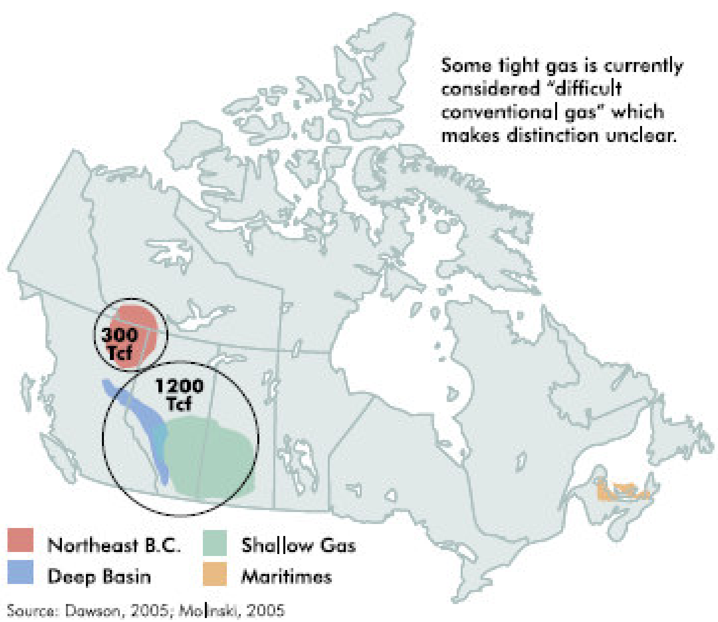


Fig. 2.7 — Tight gas potential development areas in Canada and estimated gas-in-place [18]

2.2.3 Australia

The Strzelecki sand Group of Gippsland Basin in southern Australia is estimated to have several Tcf of gas in place in two fields - Trifon and Wombat. The Strzelecki is a clay rich reservoir with a 0.2 md permeability and includes liberal amounts of smectites making conventional drilling and completion difficult. In the fields, several hydraulic fracture simulations and horizontal underbalanced drilling have been conducted. [39]

Basal Rewan sand (Triassic) and Showgrounds sand in Surat/Bowen basin have permeability ranges from 0.01 md to 2,000 md and porosity of 3%-19% with estimated recoverable of 30 Bcf gas. Until 2006 there are 12 wells drilled underbalanced into the sands, with five wells are producing 1 MMcf/d. [40]

2.3 Shale Gas

A global energy study in 1997 estimated that abundant shale gas resources are distributed mostly in North America, Latin America, and Asia Pacific (Table 2.8). Recent estimates by IFP suggest the resource ranges from 1483 to 1859 Tcf in the U.S., and 500 to 600 Tcf in Canada. In other regions of the world, this resource has been studied to only a limited extent. [5, 41]

Past studies by GTI and field experiences gained in Barnett shales conclude that the key gas producibility properties of shales are: [7, 42]

- gas content
- permeability
- thickness
- reservoir pressure

- reservoir fluid viscosity
- drainage radius

Table 2.8 – Estimated worldwide shale gas resources [5]

Region	Gas Resource in Fractured Shales (Tcf)
NAM – North America	3,841.6
LAM – Latin America	2,116.8
WEU – Western Europe	509.6
EEU – Eastern Europe	39.2
FSU – Former Soviet Union	627.2
MEA – Middle East Asia	2,548
AFR – Africa	274.4
CPA – Central Pacific	3,528
PAO	2,312.8
PAS	313.6
SAS	0
World	**16,111.2**

2.3.1 United States

The majority of shale gas production area in US is concentrated in the Forth Worth (Barnett shale), Appalachian (Ohio shale), Michigan (Antrim shale), Illiniois (New Albany), and San Juan (Lewis shale) basins (Fig. 2.8). The rest are distributed in Anadarko basin, Uinta-Piceance basin, Williston, and Paradox basins. Most shales have permeabilities as low as several microdarcies. Thus the present of extensive natural fracture systems are required to sustain gas production. Table 2.9 lists the properties of producing US shale gas basins. [11, 7, 43, 44]

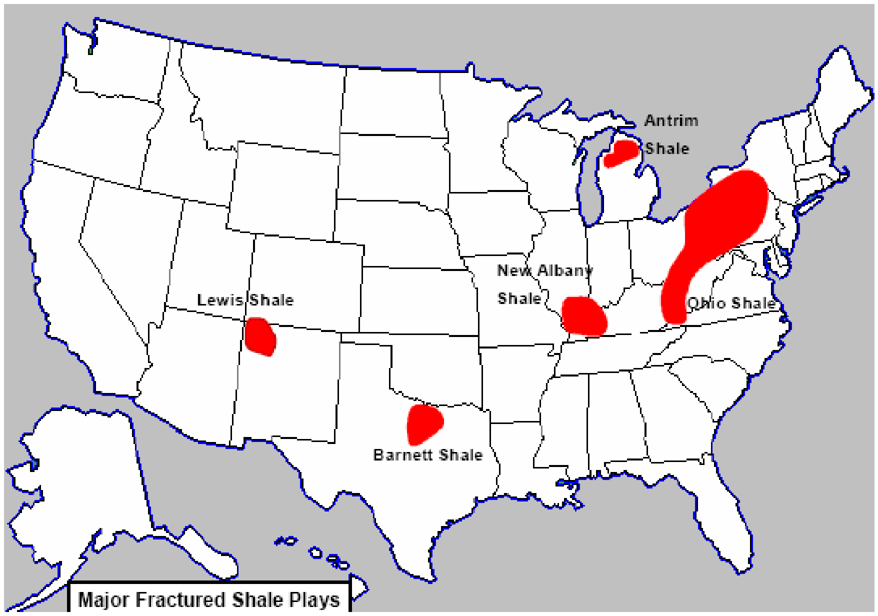


Fig. 2.8 — Major gas shale basins in United States [45]

Table 2.9 – Key properties of producing US shale gas basins [7]

Key Properties for Productive Gas Shales					
Property	Barnett	Ohio	Antrim	New Albany	Lewis
Depth, ft	6,600 – 8,500	2,000 – 5,000	600 – 2,200	500 – 2,000	3,000 – 6,000
Gross Thickness, ft	200 – 300	300 – 1,000	160	180	500 – 1,900
Net Thickness, ft	50 – 100	30 – 100	70 – 120	50 – 100	200 – 300
Bottomhole Temp, ^{o}F	200	100	75	80 – 105	130 – 170
TOC, %	4.5	0 – 4.7	1 – 20	1 – 25	0.45 – 2.5
% R_o	1.0 – 1.3	0.4 – 1.3	0.4 – 0.6	0.4 – 1.0	1.6 – 1.88
Total Porosity, %	4 – 5	4.7	9	10 – 14	3 – 5.5
Gas-filled Porosity, %	2.5	2.0	4	5	1 – 3.5
Water-filled Porosity, %	1.9	2.5 – 3.0	4	4 – 8	1 – 2
Kh, md-ft	0.01 – 2	0.15 – 50	1 – 5,000	NA	6 – 400
Gas Content, scf/ton	300 – 350	60 – 100	40 – 100	40 – 80	15 – 45
Adsorbed Gas, %	20	50	70	40 – 60	60 – 85
Reservoir Pressure, psi	3,000 – 4,000	500 – 2,000	400	300 – 600	1,000 – 1,500
Pressure Gradient, psi/ft	0.43 – 0.44	0.15 – 0.4	0.35	0.43	0.2 – 0.25
Water Production, Bw/d	0	0	5 – 500	5 – 500	0
Gas Production, Mcf/d	100 – 1,000	30 – 500	40 – 500	10 – 50	100 – 200
Well Spacing, Acres	80 – 160	40 – 160	40 – 160	80	80 – 320
Recovery Factors, %	8 – 15	10 – 20	20 – 60	10 – 20	5 – 15
Gas-in-place, Bcf/section	30 – 40	5 – 10	6 – 15	7 – 10	8 – 50

2.3.2 Canada

Shales are the most common type of sedimentary rock in the Western Canadian Sedimentary Basin (WCSB). Fig. 2.9 shows the potential shale gas development areas in Canada and the estimated gas-in-place. According to a study by the Gas Technology Institute, these shale formations, from Devonian through Cretaceous time periods, have potential of shale gas (Table 2.10). Although currently there is no commercial shale gas production, some evidence suggests that shales are contributing to conventional production within the WCSB. [7, 46]

Table 2.10 – Potential shale gas formations in Western Canada [7, 46]

Age	Formations	Est. GIP (Tcf)
Lower Cretaceous	Wilrich Member, Spirit River Fm.	156
Upper Jurasic	Passage Beds Upper Fernie Shale Green Beds	NA NA NA
Middle Jurassic	Grey Beds	NA
Lower Jurassic	Rock Creek Poker Chip Shale Nordegg	NA NA NA
Middle Triassic	Doig Doig Phosphate	11 129
Lower Triassic	Montney	187
Lower Carboniferous/Upper Devonian	Exshaw/Bakken Ireton Duvernay	NA NA 377

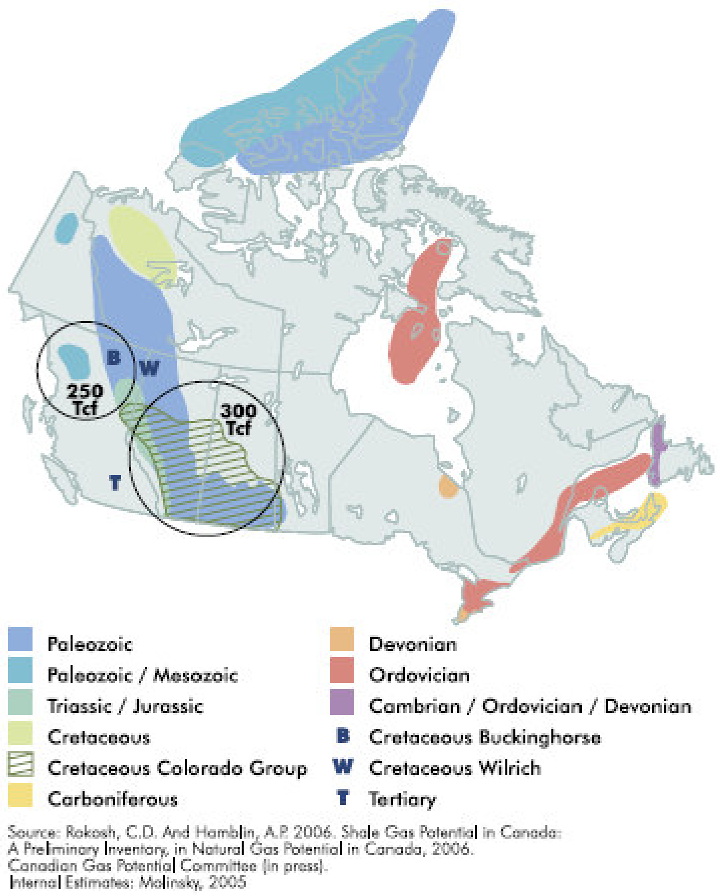


Fig. 2.9 — Shale gas potential development areas in Canada and estimated gas-in-place [18]

CHAPTER III

KEY TECHNOLOGIES IN UNLOCKING UNCONVENTIONAL GAS RESOURCES

In 2003 the National Petroleum Council (NPC) assessed factors that affect change in natural gas supply in the United States. [35] The result shows that new technologies to be the most significant factor above others such as economic growth, accessibility, and LNG imports. New and advanced technologies not only lead to the discovery of entirely new plays, but also the rediscovery of previously missed or uneconomic ones, including unconventional resources.

Beside the 2003 NPC study, several workshops were held to collect input from the industry regarding the state of technologies application in unconventional gas and future research needs. Most respondents suggested reservoir characterization and stimulation as top priority need for developing unconventional gas resources in the US. [6]

This chapter discusses some significant technologies used today in unlocking unconventional gas resources. Because many of the technical challenges between the resources are common to coal beds, tight sands, and gas shales, the application of key technologies often overlap for different types of unconventional gas resources.

3.1 Reservoir Characterization

Reservoir characterization refers to the integration of geological, geophysical, and production data and analyses to characterize reservoir properties in three dimensions.

Reservoir characterization shares important part in successfully developing unconventional gas resources, because it provides guidelines in deciding well locations, applying optimal completion and stimulation technologies; and also reducing the chance of by-passed gas because of compartmentalization and prior distribution. But reservoir characterization is often time consuming and costly. To reduce the downsides, a set of reasonable reservoir characterization workflows for different types of unconventional gas resources have been identified (Fig. 3.1). These workflows are modification of the general workflow applied to most oil and gas producing fields, with some adjustment to focus on key parameters affecting production from unconventional gas resources (highlighted in red color).

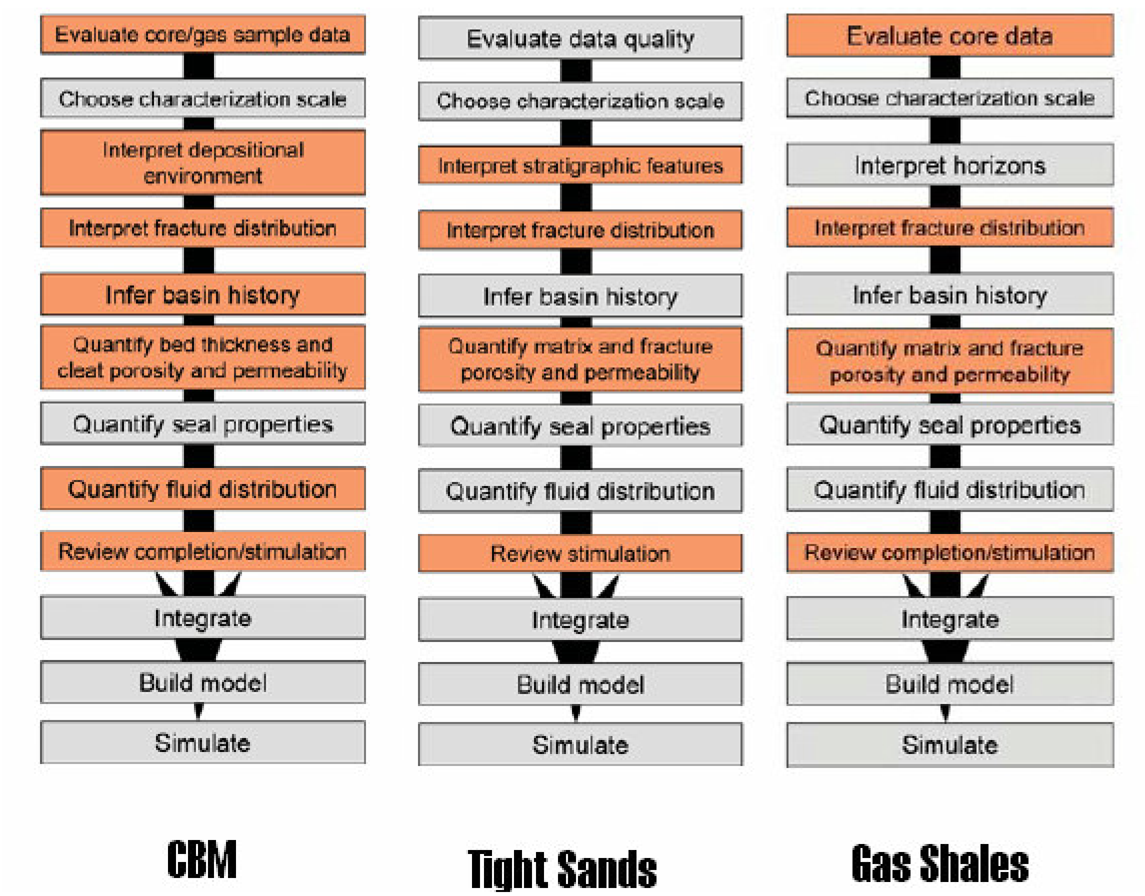


Fig. 3.1 — Reservoir characterization workflows for unconventional gas [47]

3.1.1 3D Seismic

Most widely useful technologies to enhance reservoir characterization are seismic-based. In the US, some of unconventional gas basins already have by 2D or 3D seismic data (Fig. 3.2). In some other basins, existing data may not be sufficient to extract important parameter characteristics to unconventional gas. New 3D seismic-based technologies that can provide such data include: high frequency seismic and crosswell seismic for mapping thin beds, multicomponent seismic for characterizing fractures and fracture anisotropy, and time-lapse seismic for highlighting changes in fluid distribution. Although 3D seismic is very useful, until today it is still considered uneconomic by many CBM operators. [47]

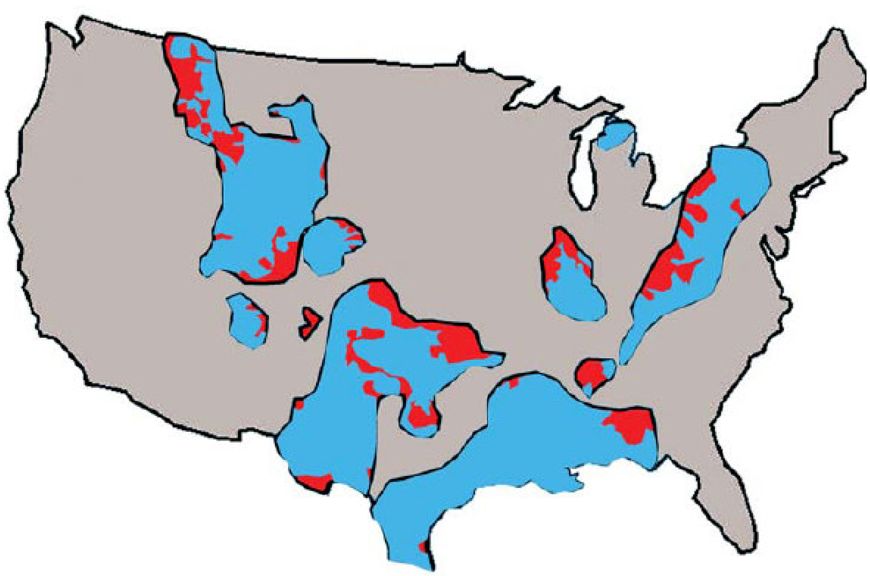


Fig. 3.2 — Unconventional gas resources areas covered by existing seismic data [47]

Spectral decomposition [48]

Spectral decomposition unravels the seismic signal into its constituent frequencies. This allows the interpreter to see amplitude and phase tuned to specific wavelengths. Since the stratigraphy resonates at wavelengths dependent on the bedding thickness, the interpreter can not only image subtle thickness variations and discontinuities, but also accurately predict bedding thickness quantitatively (Fig. 3.3). This technology also interprets small-scale reservoir changes of discontinuities that contribute to compartmentalization by improving resolution laterally. In addition, since the high-frequency response of a reflector can be attenuated by the presence of compressible fluid, spectral decomposition can also assist in the direct detection of gas. [48]

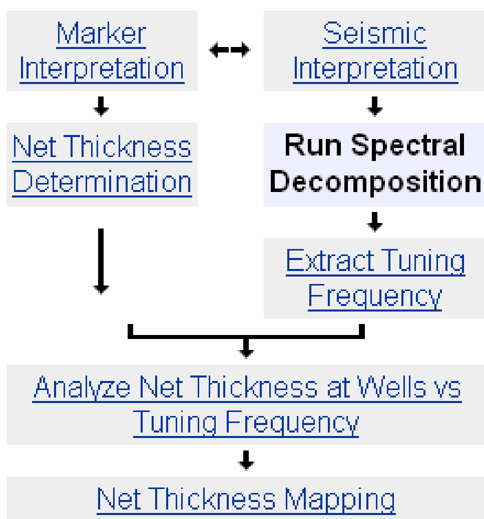


Fig. 3.3 — Spectral decomposition workflow to estimate net thickness

Stochastic fluid modulus inversion

This is a statistical comparison of real and synthetic seismic attributes to quantify the probability of a particular fluid modulus and density at a given point in the reservoir.

Stochastic fluid modulus inversion is used for evaluating the reliability of information derived from seismic and for predicting fluid distribution. It is most effectively used to assess the value of seismic attribute data as a hydrocarbon indicator in tight sands.

3.1.2 Formation Evaluation

Two tools in particular, the Elemental Capture Spectroscopy (ECS) sonde and the Reservoir Saturation Tool (RST), provide valuable evaluation information for CBM reservoirs. These tools directly measure the chemical makeup of coal and ash mineralogy and are used to estimate the discrete and cumulative coal gas volume and the degree of cleating. The geochemical measurement is largely unaffected by fluid in the well.

In the cased holed version of these tools, the contribution of the casing and annular fill to the overall measurement can be easily subtracted because the depth of investigation extends to 7 inch. The ECS sonde delivers greater measurement precision than the RST tool. However, the RST tool can be run in casing as small as 2 in., whereas the ECS sonde is limited to casing of 6 in. or larger. In addition, the RST tool uses a pulsed neutron generator, whereas the ECS sonde uses a chemical radioactive neutron source.

Dipole Sonic Imager (DPI) measures a full waveform, including the compressional wave (P-wave), the shear wave (S-wave), and the Stoneley wave (St-wave). This tool will provide information related to the orientation of earth stresses.

The Formation Micro Scanner (FMS) tool obtains a high-resolution microresistivity image of the borehole wall, which is useful for identification of lithologic units and tectonic features (e.g., the presence of fractures and faults and their orientations). The FMS tool includes a General Purpose Inclinometry Tool (GPIT), which provides tool acceleration and fluxgate magnetometer measurements that are used to orient the microresistivity images. The FMS consists of four orthogonal pads with 16 electrodes on each pad. The FMS arms are also used as calipers for hole size estimation.

In addition, advanced well log data analysis and core analysis improve determination of gas content of coals seams, a key parameter in CBM gas-in-place analysis.

3.2 Coalbed Methane

Coalbed methane (CBM) is the best example of how technology impacts development of a natural gas resource. Gas has been known to exist in coal seams since the early period of coal mining industry, but only since 1989 has gas from coal bed been significantly produced in United States. The annual CBM production was only 10 Bcf/year from 284 wells. Currently the production has grown over 1.6 Tcf/year. This high growth of production was largely driven by the combination of exploration, completion, and production technology advances in San Juan and Black Warrior basins during the late 1980s and 1990s (Figure 3.4).

In many aspects CBM production is similar to conventional gas resources, yet it differs significantly in other factors, such as:

- Coal seams adsorb natural gas, allowing more gas storage compared to conventional rocks;
- It also requires a substantial pressure drop to produce the adsorbed gas; and

- In many cases, a large volume of water needs to be removed prior to gas production.

The unconventional properties and production performance of coalbed reservoirs, including high initial water production and low initial gas production, are largely responsible for the relatively slow uptake in CBM reservoir development around the world. However, substantial research has been conducted to fully understand the principles and to develop new technology for coalbed methane production. On the other hand, several aspects in producing conventional gas resources, such as drilling process, were readily adapted for coalbed methane production.

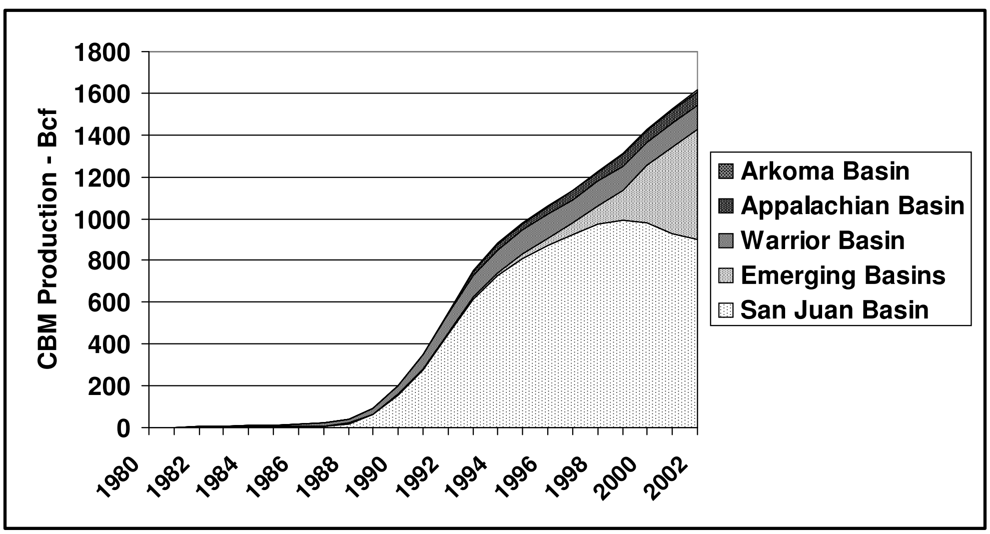


Fig. 3.4 — U.S. gas production from coal seams [6]

During the past decade, implementation of new technology in drilling, completion, and stimulation, as well as improved understanding in adsorption/desorption of gas on coal, coal cleat and cleat systems, and gas-in-place, have been significantly improved coalbed methane recovery. Several industry surveys summarize the highly significant technology advances as described in the following paragraphs.

3.2.1 Advanced Drilling and Multilateral Completions

Advanced drilling and Multilateral completions technologies enable development of thin bed coal seams, increase gas recovery, and reduce environmental impact.

Z-Pinnate Drilling

Traditional surface drilling methods used to extract methane gas from coal have historically had low production rates, low recovery factors, do not drain the reservoir uniformly, require considerable surface disturbance to drill, and encounter extended dewatering periods. But one special method, CDX Gas LLC's Z-pinnate drilling process, has been successfully increased the CBM recovery, enabled production to occur more quickly, and decreased environmental impact. This method has been proved in the Appalachian and San Juan coal basins. It is best suited for thick, low permeability coals with good lateral continuity. [49, 9]

CDX's Z-pinnate drilling is a dual well, horizontal drilling system that results in a pinnate drilling and drainage pattern. The system begins with two closely-spaced (within 20 ft) vertical wells: one well serves as an air injection well early in the project and then as a producing well; the second well serves as the horizontal and service well bore (Figure 3.5). A Z-Pinnate well drilled in a coal seam typically recover 85% to 90% of the gas in place within 24-48 months. [49]

Using the same technology, in 2004 CDX Canada established commercial production from a horizontal well in the Mannville coals, the largest CBM plays in Canada. [26]

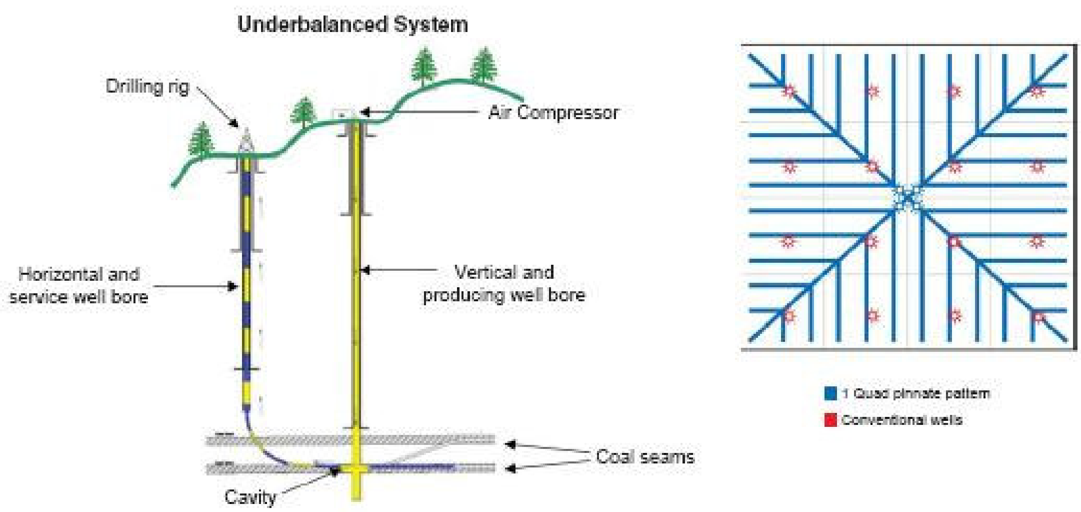


Fig. 3.5 — CDX Gas LLC's Z-pinnate drilling system [50,51,49]

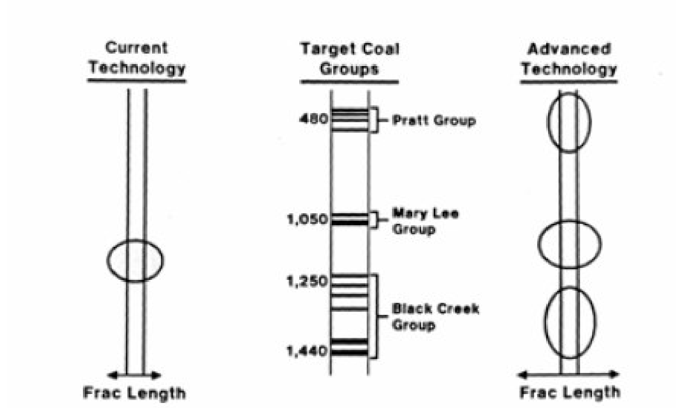
Horizontal Wells

Significant numbers of successful production from horizontal CBM wells have been reported. About two hundred horizontal wells were drilled into Hartshone Coal in the Arkoma basin with average length range from 2,000 ft to 2,500 ft, and completed with slotted liners. The study shows recovery factors range from 50% to 80%. Apparently horizontal wells are applicable to the relatively "dry" Hartshone Coal. Gas production typically occurs in the first month, without very little water production. [52]

Outside of US, horizontal wells are also preferred for CBM recovery. In 2005, Trident Exploration Corp. and Quicksilver Resources reported successful production from Manville coals in Canada. In 2006, experimental projects in Shanxi, China drill horizontal wells with promising results. They estimate recovery as high as 50% from those horizontal wells. Many of new CBM wells in Australia Bowen basin are drilled horizontally, either in pairs with a vertical well, or trios of two horizontal wells and a vertical well. This customized drilling technology decreased the capital cost of drilling a CBM well [9, 30]

Multi-seam Completions

Single well completions covering multiple, thin coal seams increases recovery per well compare to single-seam completions. Gas Research Institute (GRI) study in Rock Creek field, Black Warrior basin shows multi-seam completion, linked with advanced stimulation technology, offered nearly tripling gas recovery per well (600 MMcf/well) compare to single-seam completion (200 MMcf/well), as shown in Fig. 3.6. [53] Multi-seam completion became the strategy of choice in almost coal basins with stacked coal reservoirs. But further study by National Technology Energy Laboratory in Powder River basin shows exceptional case. Multi-seam technology is considered uneconomic due to challenges arising from the geologic and reservoir conditions unique to Powder River basin (shallow, underpressured, low gas content, low rank coals surrounded by water bearing aquifers). The study suggests the need of further completion technology development to tackle these challenges. [53]



Coal Group	CBM Resource In-Place (Bcf/Well)	Current Recovery	Advanced Technology
		CBM Recovery (Bcf/Well)	CBM Recovery (Bcf/Well)
Pratt Group	0.4	-	0.20
Mary Lee	0.4	0.20	0.28
Black Creek	0.2	-	0.12
Total	**1.0**	**0.20**	**0.60**

Fig. 3.6 — Multi-seam completions triple CBM recovery per well [53]

3.2.2 Fracture Stimulation Techniques

Hydraulic fracture completions establish the majority of coal completions. Compared with clastic rock, coal has higher fracturing gradients than its bounding layers, due to its higher Poisson's ratio and lower Young's modulus. This physical property makes coal a unique medium for fracture propagation. Additionally, coals are almost always found in multiple thin contiguous seams and highly jointed with cleats or natural fractures. These unique characteristics lead to complex fracturing. The complexity starts as early as choice of perforation type, fracs fluid, type of proppants and additive, to the fracturing diagnostic. [54]

Based on industry survey, typical perforation is 4-6 spf and 90-120 deg phasing. Small holes and deep penetration perforating is preferred because it lowers frac pressure in coals and prevent fines influx. [54]

Frac Fluids

There are lots of frac fluids choice in CBM plays. In the order of proppant carrier, they are: nitrogen gas, KCl water, slickwater (2 ppg), foamed water (2-3 ppg), linear gel (5-8 ppg), foamed gel (5-8 ppg), and cross-link gel (12 ppg). Nitrogen (N2) gas is used in Horseshoe Canyon dry coals in Alberta, Canada. In Arkoma basin, gels work better than water because water invasion can inhibit production in dry coals. Slickwater with no is used in high permeability Powder River coals. Foam and cross-link gel are used in Raton basin. San Juan practices low residue cross-link gel.

Water fracs are an alternative of proppant fracture treatments that reduces stimulation costs while maintaining conductivity rivaling that of the conventional ones. A typical modern water frac involves pumping very large volumes of lightly treated fresh water (10,000 bbl or more, lightly treated with friction reducer, surfactant and clay stabilizer) with low sand concentrations (0.5 ppg during bulk with tail-in from 0.5 to 2 ppg during last 1-5% of job). Higher sand concentrations near the end of the treatment help prop the fracture near the wellbore. Since the treating fluid is primarily water (not gel), clean-up problems sometimes experienced with conventional treatments are minimized. The low viscosity of the water treating fluid tends to maximize length while minimizing fracture height. [54]

Treatments work best in lower permeability, high Young's modulus, and normal stress coals. Water fracs have been used extensively in the Black Warrior basin.[55] A comparison of production response from 23 wells (10 water fracs and 13 conventional fracs) reveals that water fracs perform as effectively as conventional fracs at one-half of the treating costs. Long-term production showed no substantial differences in decline behavior. [54]

Surface Modification Agent (SMA)

Proppant conductivity is important because coal seams require maximum conductivity for the dewatering process, and they require the hydraulic fracture to act as a pressure sink, allowing gas desorption to occur. A proven proppant-pack technology uses a liquid Surface Modification Agent (SMA) answer the requirement. SMA is applied to proppant on-the-fly during a hydraulic fracture-stimulation treatment. This process coats individual proppant grains with a “tacky” surface, causing the proppant grains to cluster and create a network of loosely packed grains with interconnected clusters. The modified proppant grain surfaces enhance the dewatering process by promoting the flow of aqueous fluids and entrapping potentially damaging fines on grain surfaces rather than in pore constrictions. This technology has been proven at San Juan coals, both restimulation and new-drill applications. [56, 57]

Fracture Diagnostic

There are currently two main methods through which the height, length and the azimuth (in the case of a vertical fracture), of an induced fracture may be monitored. These involve the use of tiltmeters and/or subsurface microseismic monitoring equipment. An early use of fracture diagnostic will result in optimization of stimulation treatment and significant cost saving.

Tiltmeters are high resolution, angular displacement sensors that are usually arranged in one or more circular or elliptical arrays, usually within near-surface boreholes, surrounding the well that is going to be fractured. The fracture geometry is then inferred from a geophysical analysis of this data, through a mathematical inversion. Tiltmeter technology applied to a 16 wells pilot project in Copper Ridge field (South Wyoming) reduced cost by USD 1.3 million in the first year. [58]

Subsurface microseismic monitors fracture geometry at real time. It involves the downhole installation of geophones or accelerometers in offset wells, and/or the injection well itself, and the associated surface equipment used to process and store the data (Fig. 3.7). This system depends on the ability of the equipment to triangulate the location of the fracture, through the analysis of the intercepted microseismic events. The accuracy of this system depends on the number of geophones or accelerometers installed, and the spatial location of this equipment relative to the loci of the particular microseismic events of interest. The disadvantage of microseismic monitoring is the relatively high cost associated with the installation of the deep monitoring wells, which must be completed into the same interval as the injection well.

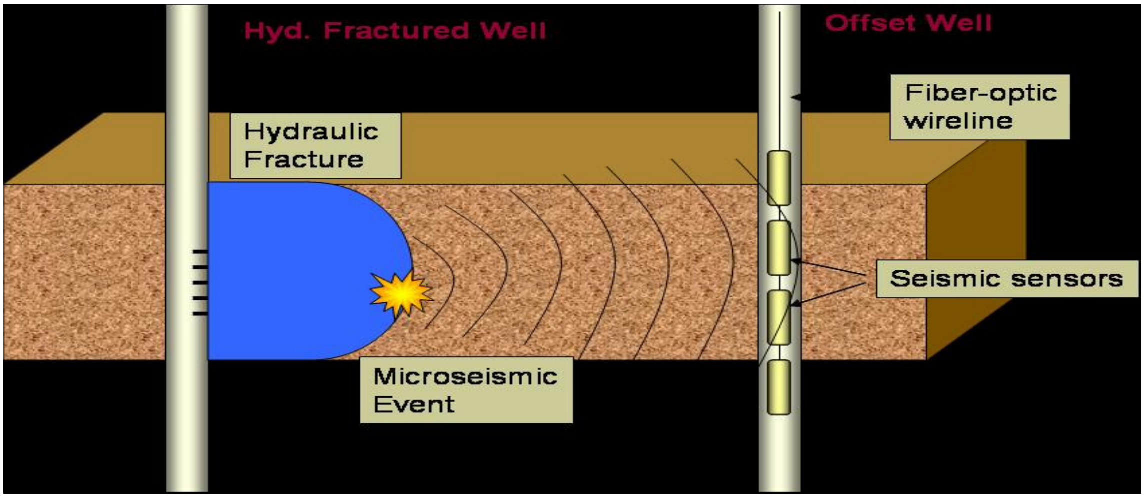


Fig. 3.7 — Microseismic fracture mapping [59]

3.2.3 Shallow or Coiled Tubing Rigs

Fit to purpose shallow gas single rigs or coiled tubing rigs (Fig. 3.8) are widely used to drill into shallow coals. These rigs reduce total drilling time, total drilling completion costs, and surface impact of operation. In Horseshoe Canyon play (Canada), a well footprint can be as small as 10 ft by 10 ft, result in minimal disturbance drilling.

Combined with fracture stimulating operation, coiled tubing rigs can stimulate multiple zones by straddling each individual productive stringer during a single trip into a well and also can treat multiple wells in a single day. When combined with specially designed bottomhole assemblies, the coiled tubing frac stimulation can effectively isolate zones of interest without the need for costly workover operations. The gas recovery is increased while total completion time and unit costs are greatly lowered.

Fig. 3.8 — Typical coiled tubing rigs [60]

A coiled tubing multiple zone stimulation project in Raton basin proved 1.5 fold increase in gas production from 14 gas wells, compare to non coiled tubing stimulation. The total operation time was reduced by half, and total cost dropped by 8%. [60]

3.2.4 Enhanced CBM Recovery Techniques

There are three main methods which can induce methane release from coal: 1) Reduce the overall pressure, usually by dewatering the formation either through pumping or mining; 2) Reduce the partial pressure of the methane by injecting another inert gas into the formation; 3) Replace the methane on the surface with another compound, such as CO_2. Enhanced CBM recovery techniques represent the latter two methods by injecting either CO_2 or N_2. The process is implemented by injecting inert gas at one location and recovering methane gas at another, as shown in Fig 3.9. [21]

CO_2 adsorption capability is greater than CH_4, which means CO_2 adsorbs more readily onto the coal matrix surface than CH_4. When injected in cleats, CO_2 diffuses into coal matrix and is preferentially adsorbed and sequestered within the coal seam at the expense of coalbed methane which is simultaneously desorbed and thus can be recovered as free gas. N_2-Enhanced CBM recovery works in a different way from CO_2-Enhanced CBM recovery. When injected in cleats, N_2 diffuses into matrix but weakly adsorbs onto coal. The injection of N_2 reduces partial pressure of methane in cleats. N_2, because it is less adsorbing, will be produced with the coalbed methane and breakthrough to the producing well quickly, giving relatively fast initial recovery of CH_4.[21, 61]

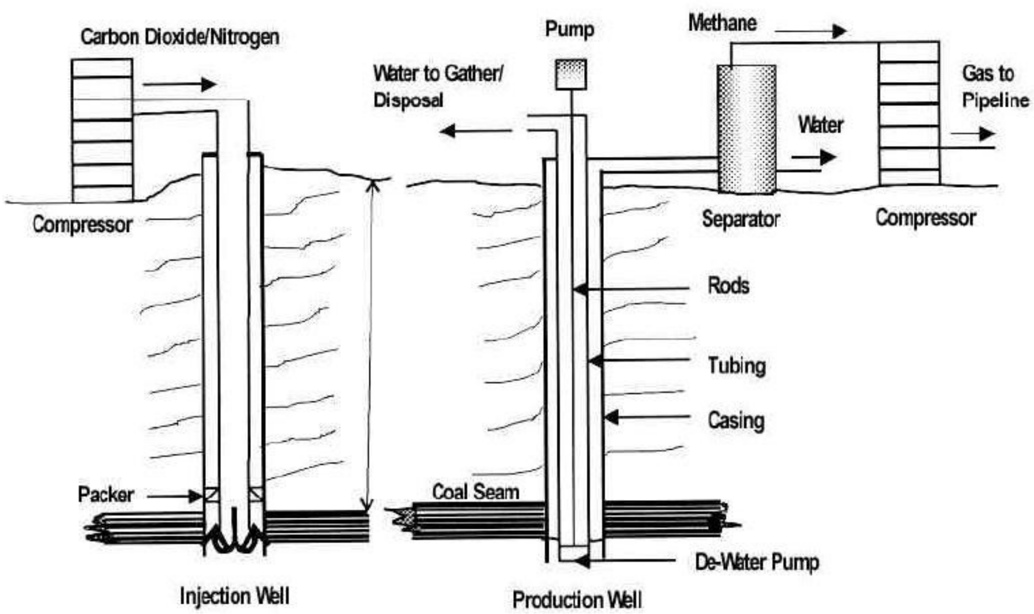


Fig. 3.9 — Enhanced CBM recovery process [62]

The adsorption of CO_2 and displacement of methane are dependent on coal grade, type, and especially on coal rank, which represents the maturation of the coal, ranging from peak to anthracite. Field tests have confirmed higher production of methane when injecting carbon dioxide and the retention of two to three times more carbon dioxide than the volume of methane produced. However, the use of nitrogen proved financially more attractive than carbon dioxide injection in the US as the nitrogen could be recovered and recycled whereas the carbon dioxide was retained by the coal. In summary, the advantages of enhanced CBM recovery includes: 1) sequester CO_2; 2) reduce the production time for CBM; 3) increase reserves and improve the recovery of CBM. [61]

Burlington Resources claimed successful CO2-Enhanced CBM project in Allison field, San Juan basin. The gas production increased by 150% compare to the conventional pressure-depletion method, while reducing the greenhouse gas from atmosphere. Several simulation studies have shown the method practiced in Allison field is applicable in Appalachian and Black Warrior basins. [61]

3.2.5 Produced Water Management

CBM recovery activities typically produce water in large volume, thus water water disposal and treatment costs are an important aspect. The quality of water produced from CBM wells vary from very high quality (meeting state and federal drinking water standards) to having very high total dissolved solids (TDS) concentration (up to 180,000 parts per million TDS) which is not suitable for reuse. Currently, the management of CBM produced water is conducted using various water management practices depending on the quality of the produced water. In areas where the produced water is relatively fresh, the produced water is handled by a wide range of activities including direct discharge (in the Black Warrior basin of Alabama and the Gulf Coast), storage in impoundments, livestock watering, irrigation, and dust control. In areas where the water quality is not suitable for direct use, produced water is run through special treatment prior to discharge and dispose through injection. [20]

Depend on the produced water's initial quality and the associated beneficial use after treatment, there are several options of treatment technologies available: Freeze-Thaw/Evaporation (FTE), Reverse Osmosis (RO), Ultraviolet Light, Chemical Treatment, Ion Exchange, Capacitive Desalination or Deionization, Electrodialysis Reversal, Distillation, and Artificial Wetlands. The FTE has a definite economic advantage over conventional evaporation technology in climates with seasonal subfreezing ambient temperatures. It is currently being practiced in Alaska, Colorado, and Wyoming to reduce the concentration of total dissolved solids in produced water. In San Juan Basin, the FTE process reduced the volume of disposal water by 80%. The RO process applied in Marathon Oil's CBM wells in Powder River basin reduced waster streams by 80%. Marathon also applied Artificial Wetlands to treat heavy mineral is produced water. Because water treatment technologies are generally limited to treating specific water constituent types, in many occasions water treatment processes are often coupled together.

Injecting water back to formations has been proven to be economical and provide an environmentally safe alternative to manage produced water in most CBM producing areas. Produced water is injected into either a coal seam aquifer or a non-coal seam aquifer. Injection into a non-producing coal aquifer will restore the hydrostatic pressure within the depleted coal seams or can be used to store water for later use. Many injection wells in Arkoma, Powder River, and San Juan basins are drilled deep such that the produced water is injected into deep underground aquifer. In summary, the actual type of injection alternatives depend on quality of the produced water and aquifer as well as the desired purpose of the injection project.

Several studies propose alternative use of CBM produced water. The alternatives include: stock watering and irrigation (agricultural use), animal feeding, fisheries, cooling tower water, coal mine use, enhanced oil recovery (waterfloods), field and car wash facilities, and fire protection. In close distance to many CBM fields, there are conventional oil and gas production fields. For some depleted conventional fields, produced water from CBM fields might be source for waterflooding project. The constraints related to this alternative us is the quality and volume of produced water.

3.2.6 Long Term Technology Development

Latest survey in the industry identifies CBM technologies advances that might be in commercial use by the year 2020 and 2030. They are presented in Tables 3.1 and 3.2.

Table 3.1 – Summary of CBM technology anticipated by the year 2020 [6]

2 0 2 0	
Technology	**Discussion**
Real-Time Sweet Spot Detection While Drilling	Will allow the steering of the drill bit to most productive areas of the reservoir.
Coiled Tubing Drilling for Wells Less Than 5000 ft.	Will allow the advantages of continuous tubing drilling to be realized (fast drilling, small footprint, rapid rig moves) to be realized for currently difficult drilling areas.
Produced Water Processing	Produced Water is processed and utilized such that it no longer is viewed as a waste stream but as a valuable product for agriculture, industrial use and for all well drilling and completion needs.

Table 3.1 – Continued

Technology	Discussion
Data Handling and Data Bases	Data bases are available and user friendly allowing access to geologic and engineering data for most North American basins, and are being developed for geologic basins worldwide.
Re-completion Technologies	Small diameter tools, re-fracturing technology, behind pipe hydrocarbon detection, lateral drilling technology have all developed and been integrated for increasing recovery from all know unconventional gas fields.
Technology Integration – Development Planning	A systematic approach to developing a CBM field integrating all technology needs development, including the ability to evaluate coal seams prior to completing wells. Effective methods to simulate coal bed performance are required.

Table 3.2 – Summary of CBM technology anticipated by the year 2030 [6]

2 0 3 0	
Technology	**Discussion**
Resource Characterization and Gas in Place Potential	All basins worldwide have been assessed for CBM potential. Databases have been established and are being made available to the producing community around the world.
Well Drilling and Completion	Well drilling technology has advanced through improvement in down hole drilling systems, better metallurgy and real-time down hole sensors allowing drilling to sweet spots, use of underbalanced drilling where needed, advantages of continuous tubing drilling and efficient utilization of multilaterals.
Enhanced Recovery	Well life has been extended through technology integration increasing gas recovery significantly over state of the art.
Worldwide Technology Dissemination	CBM technology has been disseminated throughout the world. Production has begun in those countries with geologic basins containing CBM resources.

3.3 Tight Gas Sands

The poor permeability of tight gas sands requires special technology, treatments, considerations, and design to obtain economical production. Tight gas production, first developed in the San Juan basin, was significantly aided by improvements in hydraulic fracturing technology. Together with gas price incentives, advanced technology contributed significantly in rapid development of tight gas sands all over the US. Today there are over 40,000 tight gas wells producing from 1,600 reservoirs in 900 fields from major geologic basin in the US. Following are overview of technology advances contribute significantly in tight gas sands development.

3.3.1 Fracture Modeling and Analysis

Over the last several years the industry has learned and developed seismic/geophysical technologies specific to tight gas sands. A methodology to identify high natural fracture density in San Juan basin is developed using a seismic attributes gleaned from multi-azimuth seismic data. This method shows that areas of high seismic lineament density, favorable AVO anomalies, a phase difference that correlates with low clay content, and seismically-mapped paleo-channels, correspond to those areas with the best natural fracture networks and gas producing areas. [63]

Geomechanical modeling to identify areas of open natural fracture networks in Rulison field (Piceance Basin) showed wells located within a stress envelope indicating open fractures had 1.5 to 2.0 Bcf higher estimated ultimate recoveries (EUR) than wells located outside of the envelope. This model can be applied to determine well drilling locations, especially for horizontal wells. Other study indicates that by analyzing VSP (vertical seismic profile) dataset, we can distinguished between fractured and unfractured zones, and predict the strike and dip of oriented fractures.

3.3.2 Well Stimulation

Stimulation is the key to making tight gas sand development economically viable. The evolution of stimulation techniques has been driven by new technology and an expanding range of options that can be tailored to individual reservoirs. Recent objective is stimulation technology is to develop cost-effective multiple stimulations in horizontal wells. Existing technology works, but it is still relatively expensive.

Water Fracs

As well as the case in coalbed methane, water fracturing treatment, also known as slick-water fracs, is one of favorite stimulation options to develop tight sands. In the 1990s some gas field operators applied high rate water fracs in Cotton Valley Sandstone in East Texas. They reported that water fracs results in the early production rates similar to the early production rates of cross-linked gel treatment, but with only about half of the gel treatment cost. Since then, water fracs has been widely use in tight sands. [64]

Proppant-base Hydraulic Fracturing

Although water fracs is favorable in some tight sand fields, it does not as effective as proppant-base fracs in high temperature (> 250^{o}F) tight sands and tend to have lower effective frac half-length due to phase trapping associated with the retention of the water-based fluid in the formation. In such cases, high concentration proppant-base hydraulic fracturing is favorable. Several field study in South Texas, In long term, proppant-base fracs delivers better performance than water fracs. [64]

Proppant-base should be the favorite stimulation option since reservoir engineering principles show that more natural gas should be produced from tight gas reservoirs as the fracture length and conductivity increase. But in some cases fracture fluid does not breaks and cleans-up well, thus result in shorter effective fracture length and lower conductivity fracs. This problems occur in tight gas sands with bottom hole temperature less than 250^{o}F. Russing and Sullivan proposed a solution to this problem: hybrid fracture treatment

Hybrid fracture treatment combines the advantage of both water-frac technology and higher proppant concentration gel fracture treatment to optimize fracture stimulation. This treatment uses properties of slickwater to create long fractures without excessive fracture height growth in initial stages of the treatment. Afterward, cross-linked gels at low polymer concentrations are used to transport proppant at medium concentrations deeply and uniformly into the fracture after the fracture geometry during the later stages of the treatment. Russing and Sullivan reported successful application of hybrid fracs at Bossier sands of East Texas. [64]

3.3.3 Drilling and Completion Improvement

Horizontal wells offer advantages in tight gas sands as they increase the productivity through a larger contact area with formation. In long term it reduces cost as well. But in the cases of thin multiple bedded tight gas sands, instead of drilling a horizontal well in an isolated layer, drilling multilateral wells or undulating well is be more effective. Goktas *et. al* [65] suggested drilling an undulating well that can penetrate all isolated layers outperforms up to total of three horizontal wells drilled in each isolated layers (Fig. 3.10).

One key success in developing tight gas sands is to drill a well into the vicinity of the rock that is to be produced. Tight sand gas production in Jonah field shows that drilling wells with lower spacing is effective. In this field spacing as lower as 10 acres per well is being considered to be adequately drain the gas. Thus horizontal drilling and microhole wellbores are important to be able to access tight sands with small well spacing. [12]

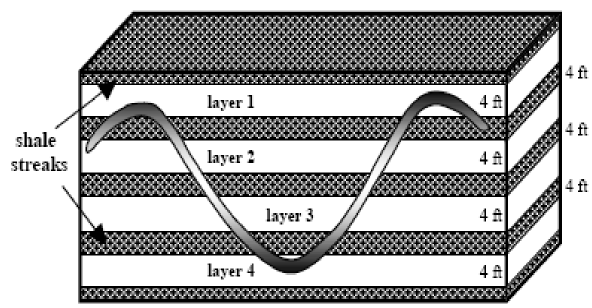


Fig. 3.10 — Undulating well outperforms single horizontal well in thin, multiple bedded tight gas sands

But overall, improvement in drilling technology is not sufficient for recovering natural from tight gas sands. It has to be accompanied by improvement in well completion and stimulation. After hydraulic fractured, a Cotton Valley tight gas sand field in East Texas records EUR per well increase by 60%, initial production increase by two fold, and drilling time reduce by 50% (Fig. 3.11).

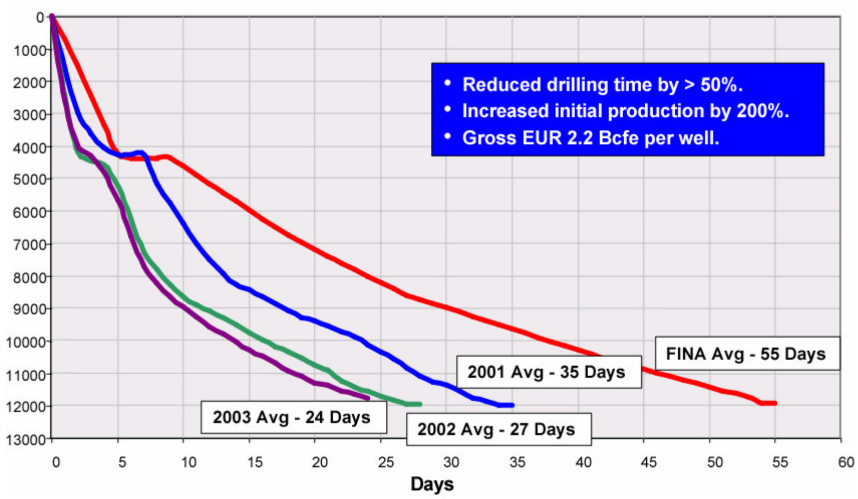


Fig. 3.11 — Result of improved drilling and completion technologies in Overton Field

In the Strzelecki sand in Gippsland Basin, Australia, wells were drilled horizontal and underbalance, to reach wider range of recovery wells were drilled, followed by hydraulic fracture, with satisfactory result.

3.3.4 Long Term Technology Development

In previous section we discuss advances in technologies that have been and is currently have highly significant impact to unconventional gas supply. Tables 3.3 and 3.4 show the latest survey in the industry identifies tight sands technologies advances that might be in commercial use by the year 2020 and 2030.

Table 3.3 – Summary of tight sands technology anticipated by the year 2020 [6]

2 0 2 0	
Technology	**Discussion**
Real-Time Sweet Spot Detection While Drilling	Will allow the steering of the drill bit to most productive areas of the reservoir.
Coiled Tubing Drilling for Wells Less Than 5000 ft.	Will allow the advantages of continuous tubing drilling to be realized (fast drilling, small footprint, rapid rig moves) to be realized for currently difficult drilling areas.
Data Handling and Data Bases	Data bases are available and user friendly allowing access to geologic and engineering data for most North American basins, and are being developed for geologic basins worldwide.
Re-completion and re-fracturing Technologies	Small diameter tools, re-fracturing technology, behind pipe hydrocarbon detection, lateral drilling technology have all developed and been integrated for increasing recovery from all know unconventional gas fields.
Technology Integration – Development Planning	A systematic approach to developing a TGS field integrating all technology needs development, including the ability to evaluate coal seams prior to completing wells. Effective methods to simulate coal bed performance are required.

Table 3.4 – Summary of tight sands technology anticipated by the year 2030 [6]

2 0 3 0	
Technology	**Discussion**
Resource Characterization and Gas in Place Potential	All basins worldwide have been assessed for Tight Gas sand potential. Databases have been established and are being made available to the producing community around the world.
Well Drilling and Completion	Well drilling technology has advanced through improvement in down hole drilling systems, better metallurgy and real-time down hole sensors allowing drilling to sweet spots, use of underbalanced drilling where needed, advantages of continuous tubing drilling and efficient utilization of multilaterals.
Enhanced Recovery	Well life has been extended through technology integration increasing gas recovery significantly over state of the art.
Worldwide Technology Dissemination	Tight Gas Sands technology has been disseminated throughout the world. Production has begun in those countries with geologic basins containing TGS resources.

3.4 Gas Shales

Gas shales technology has not been developed to the same extent as coalbed methane and tight sands technology. Lessons learned from the overpressured Barnett shale in the Forth Worth basin shows that the most critical technologies to Barnett shale success have been horizontal drilling and slick-water fracturing. These technological innovations have increased per-well gas recovery efficiency up to 20%. These two technologies are also applied in Fayetteville shale in Arkoma basin. In some fields of Arkoma basin, these treatments result in estimated ultimate recovery above 1.5 Bcf. Recently some operators in Black Warrior basin start developing Floyd/Neil shale by drilling horizontal wells. [44,66]

3.4.1 Horizontal Drilling and Hydraulic Fracturing

Horizontal drilling became a game-changing technology in the Barnett in 2003. A comparison of first full six months production shows horizontal wells produce nearly 1 Bcf, almost triple the vertical wells production of 350,000 Mcf. Horizontal wells not only produce more gas from fewer wellbores, they also allow successful wells to be drilled in areas where vertical wells were poorly performing. Based on publicly available production data, optimum horizontal well lengths are between 3,000 and 4,000 feet, including the build section. Drilling along optimum azimuth parallels the main natural fractures and allows placement of transverse hydraulic fractures will create maximum surface area for gas production from very low permeability matrix into an interconnected network of natural and induced fractures, and then to the wellbore.

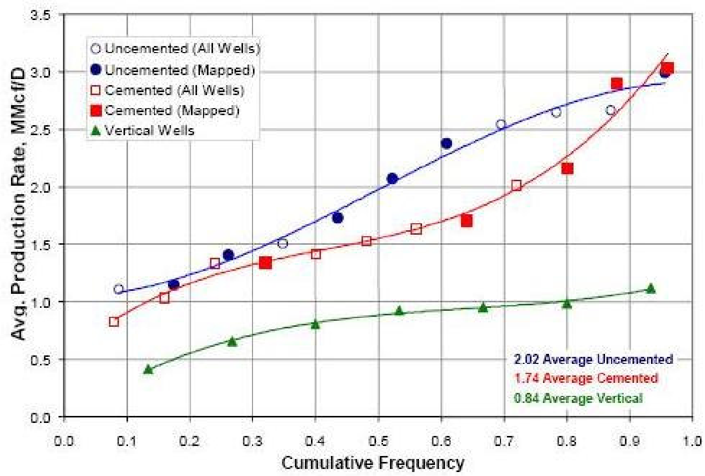


Fig. 3.12 - Fractured horizontal wells production rate was 2-3 times the vertical wells [67]

Figure 3.12 shows the result of a pilot study by Devon Energy. The study proved that hydraulic fracturing in the horizontal wells results in production increases of about 2-3 times than in vertical wells for the first 180 days. Microseismic fracture mapping has also been successfully used to improve the evaluation of hydraulic fracturing in the horizontal wells.

Wells in Fayetteville shale in Arkoma basin are almost all horizontal. The ultimate recovery is estimated between 1.3 Bcf and 1.5 Bcf per well.

3.4.2 Slick-water Fracs

Prior to 1998, most Barnett Shale wells were completed with massive cross-linked gel fracture treatments using 100,000 – 1,000,000 pounds of propping agent, usually sand. This method was expensive, and was often not effective due to fracture fluid clean-up problems. Slick-water fracturing was first applied in 1998 and soon became the favorite method. Slick water fracs saved about 30% of frac cost compare to large cross-linked gel fracs, without sacrificing production. Typical fracs jobs on horizontal wells are multi-stage. Table 3.5 shows the typical slick-water fracs design in Barnett shale.

Table 3.5 – Typical slick-water fracs design in Barnett shale [42]

Fracs Design	Vertical Wells	Horizontal wells
Fluid volume	2,200 – 2,400 gallons per foot of gross height	0.8 – 1.5 million gallon per stage (multi-stage fracs)
Pad size (% of total vol)	30% - 40%	10% - 12%
Proppant concentration	0.1 – 0.65 lbs/gal	0.1 – 0.65 lbs/gal
Sand type	40/70 and 20/40 Ottawa	40/70 and 20/40 Ottawa
Pump rate	40 – 85 bpm	70 – 100 bpm (5.5 inch casing) and 150 – 200 bpm (7” casing)

The most recent trend in Barnett shale is the simultaneous fracturing of paired offset wells. The theory behind this new technology is to minimize intrusion of frac fluid and proppants as a result of high-induced stresses caused by frac slurry injection. The short term production data shows that this method promises better results compare to non-simultaneous frac offsets.

3.4.3 Long Term Technology Development

Based on input from in the recent industry workshop, following are technologies advances in gas shales that might be in commercial in the next 10 to 20 years (Table 3.6).

Table 3.6 – Summary of long term gas shales technology development

Technology	Discussion
Fractured shale formation testing techniques	Improve recovery rate from existing wells
3D seismic applications for imaging layers and natural fractures in shale reservoirs	Improve recovery rate from existing wells
Reservoir simulation methods to incorporate all the layered reservoir description, the horizontal wells and the effect of hydraulic fractures	Improved analyses of well productivity will improve the understanding of infill drilling and completion methods needed to optimize gas recovery
Shale facies identification using geochemical source rock analysis and well logs	Increase the exploration success rate

CHAPTER IV

IMPACTS OF THE IMPORTANT TECHNOLOGY

Technology has historically contributed significantly to the petroleum industry's ability to explore, develop, and produce natural gas resources. But it is difficult to precisely determine how much of an impact technology has had, since the industry does not measure the impact of technology directly. The best parameters are production performance or cost trends in any given area or field. The other indirect evidence is the environmental impact.

In previous chapter we discuss the highly significant technology currently available for each type of unconventional gas resource. The technology is originally applied in the US, and later, after modifications to suit local situation, transferred to Canada, Australia, China, etc. It is expected that the impact of technology applied in one basin or formation will resemble the impact to the other basin or formation. Table 4.1 summarizes the impacts of the advanced technology:

Table 4.1 – Summary of impacts of technology

Advanced Technology	Impacts
3D seismic	Increase success rate of exploration or development wells [47, 48, 18]
Advanced logging tools and analysis	Increase success rate of exploration or development wells [47, 18]
Coal Beds	
Z-pinnate multilateral wells	Increase gas recovery up to 85% [49, 50, 9]
Horizontal drilling	Increase gas recovery up to 50% [49, 50, 9]
Multi-seams completion	Improve gas recovery almost 3 times of single-seam completion [53]
Water frac	Reduce cost to almost 50% [55, 9]
Fracture diagnostic	Reduce fracturing cost [9]
Coiled-tubing frac	Increase gas production, reduce cost, reduce environmental impact [9, 18]
Enhanced recovery	Improve gas recovery, reduce waiting period to initial production, reduce CO2 emission to air [21, 61]
Produced water management	Reduce volume of disposal water up to 80% [20]
Tight Sands	
Slick water frac	Reduce frac cost by half [12]
Hybrid frac (slick water + proppant)	Longer fracture with high conductivity [12]
Underbalanced drilling	Maintain permeability around well [40, 68]
Gas Shales	
Horizontal well + proppant frac	Improve gas production about 2-3 times [67, 42]
Slick water frac	Saved about 30% of frac cost compare to large cross-linked gel fracs, without sacrificing production [42, 69]

4.1 Natural Gas Supply

In US contribution of unconventional gas to total natural production has been increasing. Figure 4.1 shows that from 1997 to 2004, total unconventional gas production has increased from 4.8 Tcf to 7.5 Tcf, or equal to 26% to 40% of total natural gas production. Based on recent development of technology for producing unconventional gas resources, Energy Information Agency (EIA) forecasts that unconventional gas production will increase 77 Bcf averagely every year until it reach about 9.5 Tcf by the year 2030 (46% of total natural gas production).

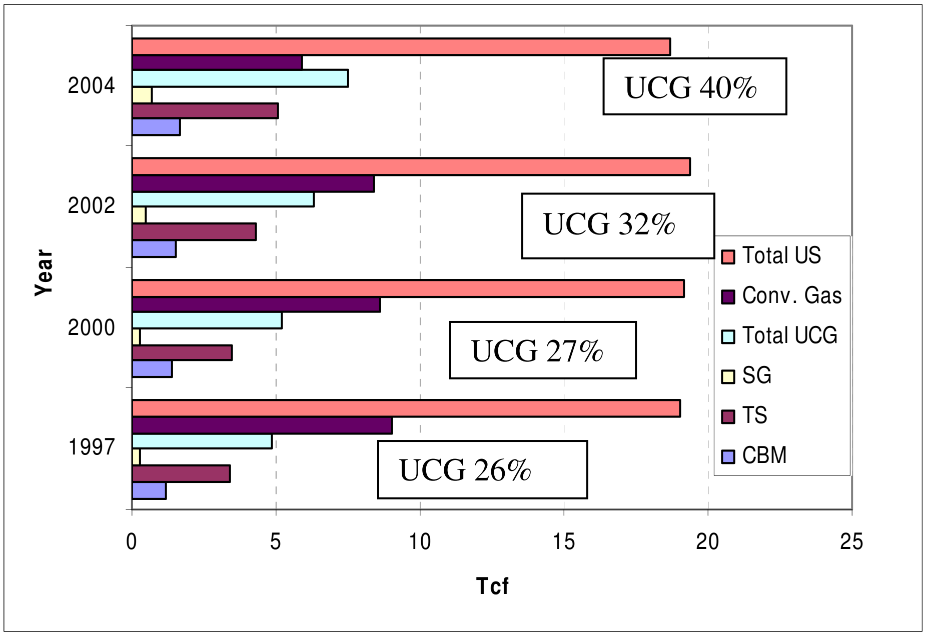


Fig. 4.1 — Production of unconventional gas compares to total natural gas production in the US (1997 – 2004) [8]

The same trend is observed in Australia and Canada. Coal bed methane production in Australia, as shown in Fig 4.2, increases from 2.36 Bcf in 1996 to 42.43 Bcf in 2004. These numbers represents 0.2% to 3.4% of total Australia natural gas production. About 70% of total CBM production in 2004 comes from Surat and Bowen basins. When we traced back to drilling activities in 2002 and 2003, most of the new wells were drilled horizontally, especially in Bowen basin. It is reasonable to believe horizontal drilling technology increase the CBM production. According to 2006 Australia energy outlook by Australian Board of Agricultural and Resource Economics (ABARE), the CBM production is projected to reach 300 Bcf by 2030, or equal to bout 6.3% of total natural gas production. Unfortunately there is not sufficient data of Australia gas production from tight sands and shales.

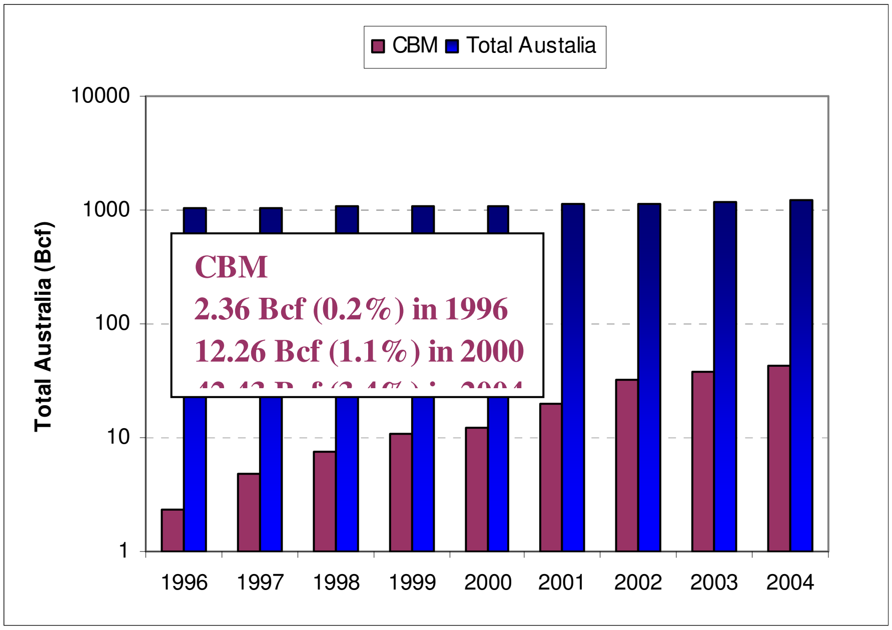


Fig. 4.2 — Production of unconventional gas compares to total natural gas production in Australia (1996 – 2004) [30]

Production of unconventional gas in Canada is more recent, and only CBM production is widely recorded. Fig. 4.3 shows that in 2003 and 2004 CBM production is around 0.5 Bcf or about 3% of total natural gas production in Canada. Most of the production came from shallow vertical wells in Horseshoe Canyon coals. In 2005 we observe a huge increase of CBM production to 1.3 Bcf. Beside multiseams completed wells in Horseshoe Canyon, the other contributor is production from the horizontal and multilateral wells drilled into Manville coals. National Board of Energy (NEB) of Canada forecasts the production of natural gas rise to 7.5 Tcf/year by the year 2025. With the declining trend of conventional gas resources, it means unconventional gas resources is expected to contribute 40% of total natural gas production. Similar to Australia, there is not sufficient gas production data from tight sands or shales in Canada.

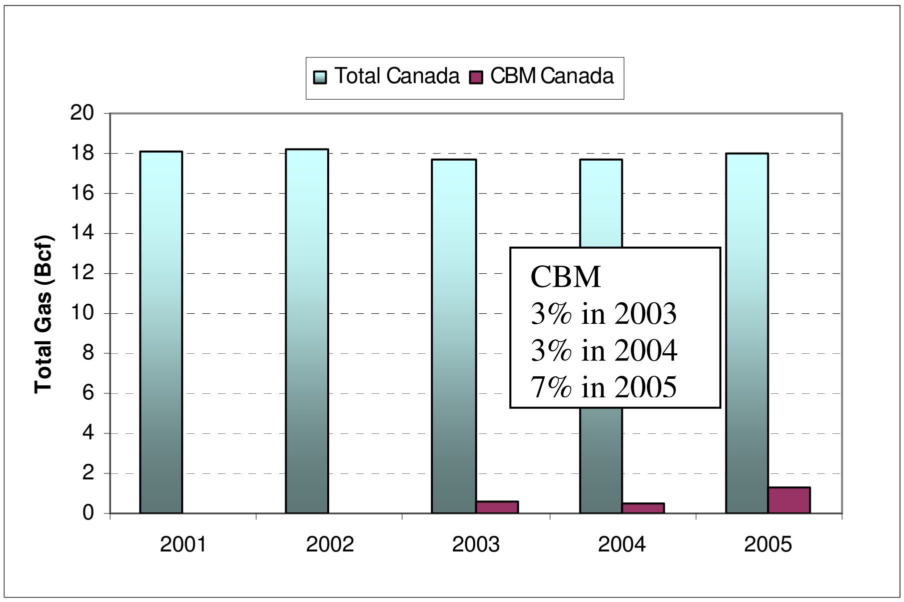


Fig. 4.3 — Production of unconventional gas compares to total natural gas production in Canada (1997 – 2005) [26]

Currently we can only compile production data from these three countries. With the rising of interests and activities in other parts of the world, and more transfers of technology in progress, we will see the increasing supply of natural gas from unconventional resources.

4.2 Costs

The costs to recover natural gas from unconventional resources are generally higher than conventional resources. But the introduction of more fit-to-purpose technology will reduces the costs. Coiled tubing rigs for shallow wells, for example, reduce the total operation time by half, and total cost by 8%. The water fracs is still widely use in East Texas tight sands because it costs half of the gel frac to recover the same volume of gas. Slick water fracs in Barnett shale saved about 30% of frac cost compare to large cross-linked gel fracs, without sacrificing production. Introduction of fracture monitoring and diagnostic reduces the stimulating cost by targeting specific zone instead of performing massive fracs. The capital cost of drilling CBM wells has decreased in Australia with the introduction of pairing horizontal well to vertical well. The more we understand the unconventional gas reservoirs, the better we can tailor technology to recover the gas, and less cost are needed.

4.3 Environment

Expanding unconventional gas resources is not without significant challenge. One key concern is the impact to environment. For instance, produced water involved in coal-bed methane recovery. Currently, the produced water is managed using various water management practices depending on the quality of the produced water. In areas where the produced water is relatively fresh, the produced water is handled by a wide range of activities including direct discharge (in the Black Warrior basin of Alabama and the Gulf Coast), storage in impoundments, livestock watering, irrigation, and dust control. In areas where the water quality is not suitable for direct use, produced water is run through special treatment prior to discharge and dispose through injection. In San Juan Basin, the Freeze-Thaw/Evaporation technology reduces the volume of disposal water by 80%. The Reverse Osmosis process applied in Marathon Oil's CBM wells in Powder River basin reduces waster streams by 80%.

Another impact of technology involves in unconventional gas recovery is toward the greenhouse gas emission. Taking advantage of the preferential adsorption of CO2 and consequent releasing of the methane gas, sequestration in CBM operation is able to reduce the greenhouse gas emission. The retention of carbon dioxide is up to three times more than the volume of methane produced.

The coiled-tubing rig is smaller in size compare to conventional rig. Some coiled-tubing rigs leave footprints as small as 10ft by 10ft, thus reduce the surface impact of operation.

4.4 Analogy Assumption for Transferring Technology

Although there are no two identical geological basins or formations, it is moderately safe to assume that if the key properties of two unconventional gas basins or formations more or less agree with each other, it is expected that the impact of certain technology applied in one basin or formation will resemble the impact to the other basin or formation. This analogy assumption is initially adapted by Canadian CBM industry (in 2001) to transfer technology from the US. For example Table 4.2 shows that some key parameters (gas content, depth, number of seams, permeability) of Horseshoe Canyon coals in Canada are close to Cherokee coals in Kansas area. The Canadian assumed that the multi-seams completion technology that has been applied to Cherokee coals will deliver about the same production in Horseshoe Canyon. In fact, the 2003 CBM production of Horseshoe Canyon has reached up to 200 Mcf/day, better than the Cherokee's production of the same year. This analogy assumption is a good start in deciding which technology to be transferred.

Table 4.2 – Key properties of Horseshoe Canyon and Cherokee coals [70]

Parameter	Horseshoe Canyon	Cherokee
Age	Upper Cretaceous	Pennsylvanian
Rank	Subbituminous	Hi-volatile bituminous A
Depth, m	250-650	120/460
Number of seams/height, m	25/12	17/4
Gas content, cc/g	2-4	2
Permeability, md	1-15	3
Gas rate/water , mcfd/bpwd	30-200/0	100/10

CHAPTER V

CONCLUSIONS AND RECOMMENDATION

5.1 Conclusions

Based on this study, I offer following conclusions:

(1) Advanced technology is one of the main drivers in increasing unconventional natural gas production, as observed in the United States, Canada, and Australia.

(2) Fit-to-purpose technology reduces the cost to recover gas from unconventional resources. The more detailed the unconventional gas reservoir is, the better we can tailor specific technology to recover the gas, and less cost are needed.

(3) 3D seismic, horizontal drilling, multilateral completion, water and gel based fracturing, coiled tubing rig, enhanced recovery, and produced water treatments are current important technologies critical in developing unconventional gas resources. More advanced technologies with significant impacts are expected to be available in the next decades.

(4) If the key properties of two unconventional gas basins or formations more or less agree with each other, it is expected that the impact of certain technology applied in one basin or formation will resemble the impact to the other basin or formation. This analogy assumption is a good start in deciding which critical technology to be transferred to undeveloped unconventional reservoirs.

5.2 Recommendation

There are several areas where this study can be improved. I recommend that future works:

(1) Expand the characterization of unconventional resources to the lowest possible level, especially for the tight sands and shale. and include

(2) Incorporate more geological and engineering information from regions with significant volumes of unconventional gas.

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APPENDIX A

ABBREVIATIONS

CBM	Coal Bed Methane
SG	Shale Gas
TS	Tight Sands
UCG	Unconventional Gas
EIA	Energy Information Agency (United States)
ABARE	Australian Bureau of Agricultural and Resource Economics
NEB	National Energy Board (Canada)
MMBW	Million barrel of water
Mcf	Thousand cubic feet
Bcf	Billion cubic feet
MMcf	Million cubic feet

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