Asia-Pacific Economic Cooperation

Advancing Free Trade for Asia-Pacific Prosperity

Effective Coalbed Methane (CBM) Recovery Technologies for APEC Developing Economies

APEC Energy Working Group

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1. Preface

1.1 The Background of the Project

The declaration of the 23rd APEC Economic Leaders' Meeting, held in Manila, the Republic of the Philippines in November 2015, noted that “affirm the importance of energy resiliency in promoting energy security”.

According to global energy consumption forecast, fossil fuels will still be the major source of global energy before 2035. Fossil fuels mainly include coal, petroleum, and natural gas, among which natural gas is the cleanest. From energy proportion trend, the proportion of natural gas in energy consumption has been increased year by year with the development of world economy and the great attention paid by global population to the environment, as well as energy conservation and emission reduction. However, when the case is seen from energy composition of APEC economies, natural gas is scarce in most APEC economies except Russia and the United States with abundant natural gas reserves; and the gap between consumption and output is relatively prevalent. Coal bed methane (CBM), which is one kind of un-conventional natural gas, contributes to clean energy supply of developing economies which need large amount of energy consumption to boost economy growth, and provide a clean energy source to support energy security for APEC economies. Moreover，CBM helps enhancement of the energy supply capacity of the regions.

The declaration of the 22nd APEC Economic Leaders' Meeting, held in Beijing, People’s Republic of China, in November 2014, noted that “support the efforts to promote economic restructuring and upgrading in traditional industries, explore new and promising economic growth are promote green, circular, low-carbon and energy-efficient development”. CBM recovery and utilization are a new growth area for traditional coal mining industry for three reasons. Firstly, CBM recovery will promote green and low carbon development of coal industry. Secondly, utilization of CBM to replace coal is able to reduce carbon emission.

CBM is promising economic growth area for coal companies which can increase their efficiency of energy utilization. Thirdly, mining safety will also be improved in coal blocks with CBM recovery before coal mining.

The recoverable CBM in the 21 APEC economies is 28,700 BCM. Some APEC developing economies like Indonesia; Mexico and Viet Nam are also rich in CBM reserves. But due to lack of appropriate recovery technology, their utilization of CBM resource remains low. Some APEC economies have already developed lots of matured and advanced technologies on CBM development, such as Australia; Canada; People's of Republic of China and United States. The problem becomes urgent to set up best practice guidance of effective CBM Recovery Technologies for APEC Developing Economies.

The project is expected to establish guidance for selection of suitable CBM recovery technologies according to specific developing economies' geological conditions, and also promote cooperation of technology and equipment exchange on CBM recovery among APEC economics.

The Beijing Declaration "encourages stronger cooperation between member economies to support activities on oil and gas exploration and development, non-conventional oil and gas exploration and development in the APEC region, the establishment of a mechanism to share best practices on unconventional oil and gas exploration and development, and off-shore oil and gas exploration and development." This project will function as a bridge between economies with mature CBM recovery technologies and economies huge potential reserves. This project needs cooperation of many APEC economies experts and research staffs work together to establish best practice guidance of CBM development in APEC developing economies.

1.2 The Purpose and significance of the Project Research.

1.2 The Purpose of Project

As introduced in the background of the project, some APEC developing economies are rich in CBM resources, but lack of recovery technology. Meanwhile, some APEC economies have already developed lots of matured and advanced technologies for CBM recovery. In order to reduce research repeated investment, the risk of CBM development investment in economies and promote APEC economies CBM production, it’s very important that the Best Practice Guidance is established for selection of suitable CBM recovery technologies according to specific developing economies’ geological conditions. The detailed purpose of the project is as follow:

(1) Summarize the s mature CBM well types and fracturing technologies of CBM development in United States, Canada, Australia and China.

(2) Accelerate in-depth and broad exchange of experiences and information on CBM recovery technologies among APEC economies.

(3) Establish best practice guidance of CBM recovery technologies for APEC economies.

(4) Work out policies and suggestions for relevant government departments on the difficulties during the development and promotion of the CBM recovery.

1.3 The main research Content

1.3.1 Collect and study mature CBM well types and fracturing technologies;

The Beijing Fanluyang Energy Technologies Institute based on more than ten years of accumulated research results organized the project research team and a group of interns from the postdoctoral, doctoral and postgraduate students of the China University of Petroleum (Beijing) to make surveys and research work. The geographical scope of the survey included APEC major economies and the technical scope of the survey included coal seams. Gas resources, CBM well types, drilling and completion technologies, fracturing and stimulation technologies, etc.

The project makes a comprehensive review of currently mature technology on CBM well types and fracturing technologies. CBM well types include vertical well, horizontal well, Multi-branch Horizontal Well U shape well, and etc. Fracturing technologies include Direct Fracturing Technology, Coiled Tubing Fracturing Technology, N_2 Fracturing Technology, CO_2 Fracturing Technology, Indirect Fracturing Technology and etc.

1.3.2 Conduct domestic and international on-site investigations

Select sites in China and conduct in-situ field investigation, collect data and information. Beijing Fanluyang Energy Technologies Institute select PetroChina Huabei Oilfield Company, the largest central enterprise and the case of CBM large scale development in China, Shanxi Blue Flame Coalbed Methane Group Co., Ltd., a local large-scale enterprise with large development scale, PetroChina Zhejiang Oilfield Company, a central enterprise with small development scale and Lanhua Company, a local enterprise with small development scale, were selected for the investigation.

After by approval by the APEC Secretariat, the research project teams dispatched a three-person APEC project research team to make on-site investigation in Indonesia from March 11 to March 17, 2018. Leaded by Professor Ma Dongmin, the team members include Associate Professor Zhang Xiao and Dr. Wan Yi. During the investigation period, the investigation team visited Economic Research Institute for ASEAN and East Asia，Geological Agency of the Ministry of Energy and Mineral Resources of the Republic of Indonesia，InstitutTeknologi Bandung and PetroChina International Companies (Indonesia). The investigation content included regulations and laws related to the development of Indonesian energy and mineral resources, attitudes of the government and the private sector towards foreign investors, etc.

1.3.3 Work out the CBM recovery technology selection guidance.

The project research analyzed Characteristics, Advantages and disadvantages and summarized the Case study of different CBM well types and fracturing technologies.

1.3.4 Develop assessment tool for CBM recovery technology selection;

Based on the results of summary of on-site investigation to APEC developing economy, the project team analyzed and summarized applicability condition of different types of CBM wells and fracturing technologies. Experts in APEC region was consulted through multiple methods like virtual meeting, e-mail and phone call. The assessment tool for CBM recovery technology selection was developed by the project research teams.

2 The CBM Resources and Current Development Status

2.1 The Coalbed Methane Resources of APEC Economies

2.1.1 Overview

According to the statistics of International Energy Agency (IEA) in 2010, CBM resources buried in 2000m underground for global onshore coalfields are about 256.1 trillion m^3 that is twice as much as the proved reserves of conventional natural gas. The six economies with the most abundant resources are Australia; Canada; Indonesia; Russia; People's Republic of China and the United States.[1] The distribution of CBM resources in the APEC main economies is shown in Table 2.1.

Table 2.1 CBM Resources in APEC Economies

Economies	**CBM resource (Trillion m^3)**
Australia	8-14
Canada	17.9-76
Indonesia	12
Russia	83.7 (17-113)
People's Republic of China	36.8
United States	21.4

2.1.2 Australia

2.1.4.1 Coalbed Methane Reserves in Australia

CBM is a form of natural gas occurs naturally in some coal deposits and it is becoming one of the largest energy resources in Australia. The coal basins of Queensland and New South Wales—the Surat, Bowen and Galilee basins in Queensland and the Gunnedah, Gloucester and Sydney basins in New South Wales—hold large CBM resources, with further potential resources in South Australia.

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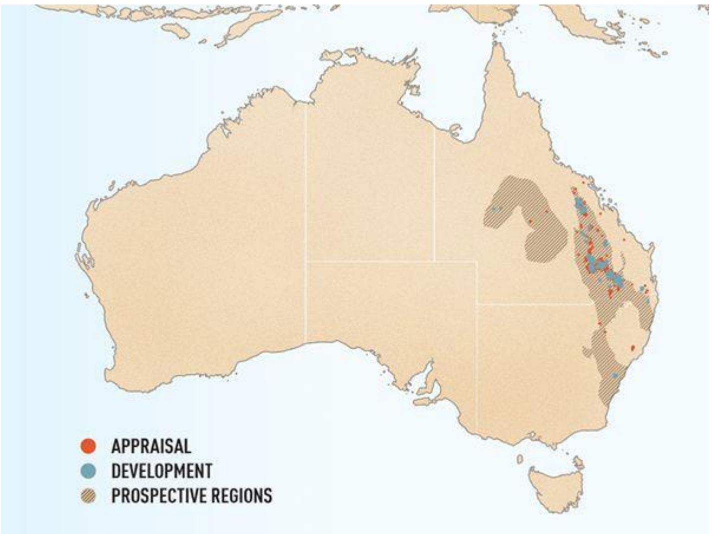


Figure 2.1 Coalbed methane regions in Australia

Source: natural coal seam gas

CBM is expected to remain the most important sector of the unconventional gas industry in Australia. It is already a significant source of domestic gas and LNG exports in eastern Australia. Australia's identified CBM reserves have grown substantially in recent years. In 2014, the CBM reserve in Australia was 1218 BCM (45 520 PJ), nearly three times the 2008 EDR estimate of 428 BCM (16 590 PJ) and accounted for about 38 percent of the total gas reserves. Reserve life is around 130 years at current rates of CBM production. More than 93 percent of the reported CBM reserves are in Queensland; the remainder is in New South Wales. In addition to reserves, Australia has substantial contingent resources (906 BCM, 33 920 PJ) of CBM. No reserves have been reported from deep coal gas exploration.

Table 2.2 Total Australia gas resources

Resource category	**Conventional gas**		**Coalbed methane**		**Tight gas**		**Shale gas**		**Total gas**	
	PJ	**BCM**	**PJ**	**BCM**	**PJ**	**BCM**	**PJ**	**BCM**	**PJ**	**BCM**
Reserves	77,253	1982	45,949	1218	39	0	0	0	123,241	3228
Contingent resources	108,982	2803	33,634	906	1,709	57	12,252	311	156,578	4049
All identified resources	186,235	4786	79,583	2124	1,748	57	12,252	311	279,819	7277
Prospective resources	235,913	6060	6,890	198	48,894	1246	681,273	17528	972,969	25060

Source: Geosicence Australia

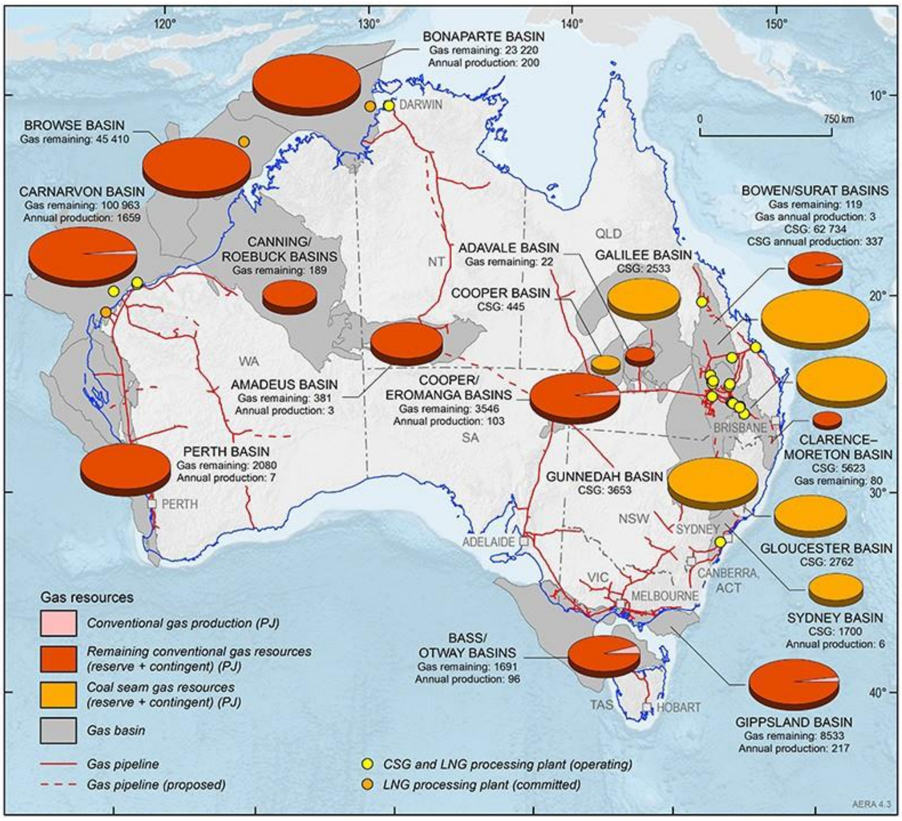


Figure 2.2 Australia's identified natural gas and CBM resources, and annual production (PJ)

CBM = Coalbed methane; LNG = liquefied natural gas

Note: For remaining resources, conventional gas values represent total demonstrated resources; CBM values show 2P reserves.

Source: Geoscience Australia

2.1.4.2 Main Coalbed Methane Basins in Australia

(1) Bowen Basin

The Bowen Basin is a large, intercontinental coal-bearing basin that developed in eastern Queensland during the Early Permian —Middle Triassic as the northern part of a much larger basin system that also includes the Gunnedah and Sydney Basins in New South Wales. The Bowen Basin has vast coal resources, with major open cut and underground coal mines in the north of the basin. Large volumes of methane gas are held at shallow depths within Permian coals in the north and have potential for coal seam methane developments. Up until 2014–15, the Bowen Basin had been the largest cumulative CBM producing basin. Certified proved and probable CBM reserves have remained steady. At June 2016, the proved and probable CBM reserves of Bowen Basin had been up to 268 BCM.

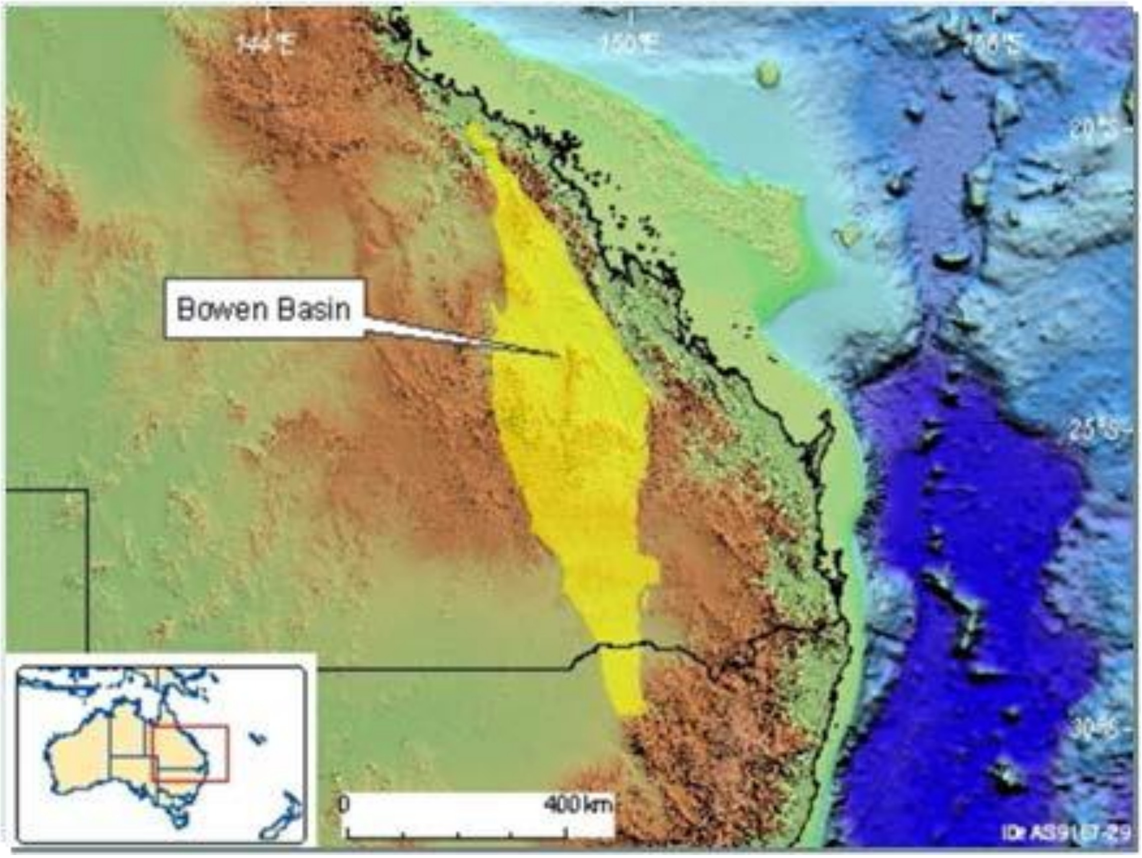


Figure 2.3 Location map of Bowen Basin

Source: Australian Government

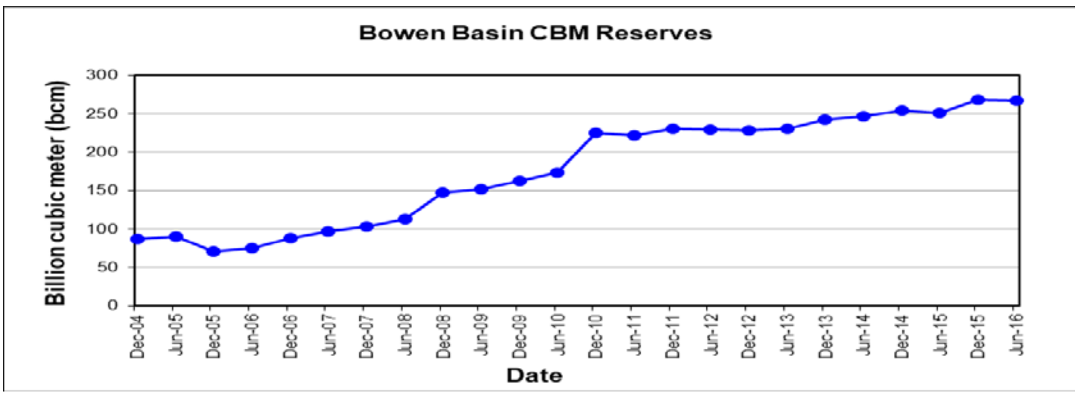


Figure 2.4 Bowen Basin CBM reserves

Resource: Queensland Government data

(2) Surat Basin

The Surat Basin is a geological basin in eastern Australia. It is part of the Great Artesian Basin drainage basin of Australia. The Surat Basin is the largest coalbed methane basin in Australia (AGRA, 2012). Most of the CBM resources present within the basin occur in the Middle Jurassic Walloon Subgroup that predominantly comprises the 'Walloon Coal Measures'. Coals in the Surat Basin were not as deeply buried as those in the Bowen Basin and therefore are less thermally mature, with generally lower gas contents.

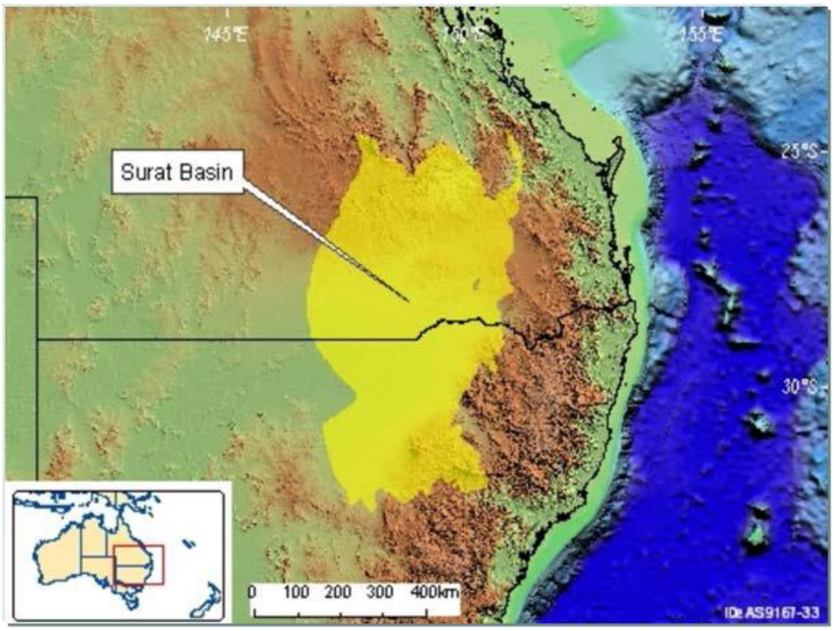


Figure 2.5 Location map of Surat Basin

Source: Australian Government

Certified proved and probable reserves in the Surat Basin have increased significantly since 2006. By 2008 more certified 2P CBM reserves had been reported for the Surat Basin than the Bowen Basin. From 2011–12 , CBM production from the Surat Basin has been higher than that from the Bowen Basin. In 2015–16, CBM production from the Surat Basin was more than four times that of the Bowen Basin.

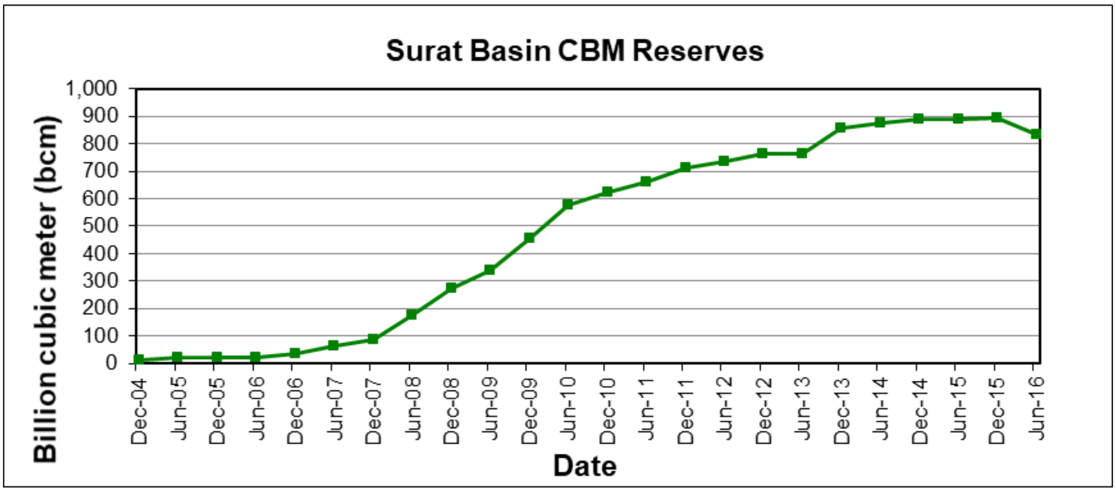


Figure 2.6 Surat Basin CBM reserve

Resource: Queensland Government data

2.1.3 Canada

2.1.3.1 Coalbed Methane Reserves in Canada

(1) Resources

Canada's gas in place from both conventional and unconventional resources is estimated to be almost 111 TCM (Petrel Robertson, 2010), a function of including the very large contribution unconventional resources make to the total resource estimate (CBM is about 23TCM), dramatically changing the picture of Canada's gas potential (Table 2.3).

Table 2.3 Canada's Gas in Place Resources

Conventional (Remaining GIP)	20
Coalbed Methane	23
Tight Gas	37
Shale Gas	31
TOTAL	111

Units: TCM

Source: Canadian Society for Unconventional Gas, 2010

(2)Marketable Resources

Canada's marketable natural gas resource potential is estimated to be between 20 and 37 TCM, after providing for considerations that constrain gas recovery and allowing for removal of impurities and fuel for surface facilities. This estimate is a significant increase from previous estimates which addressed conventional resources, while acknowledging that natural gas from unconventional sources could play a significant role in the future without quantifying the potential. This assessment includes both conventional and unconventional resources.

During the past several years the development and widespread deployment of a variety of horizontal drilling and companion reservoir stimulation technologies has demonstrated that vast additional natural gas resources within coal seams, tight gas reservoirs and shales will play a major role in shaping Canada's long term natural gas supply opportunity. The emerging nature of much of Canada's unconventional gas resource is reflected in the broad range of potential marketable gas.

Table 2.4 Canada's Estimated Marketable Gas Resources

Conventional (Remaining GIP)	10
Coalbed Methane	1-4
Tight Gas	6-13
Shale Gas	4-10
TOTAL	21-37

Units: TCM

Source: Canadian Society for Unconventional Gas, 2010

Most of the resource occurs in Alberta, and production has been established in areas of two of the three main coal-bearing formations (Horseshoe Canyon and Mannville). The Horseshoe Canyon Formation CBM resources lie in a multi-layered package of sedimentary rocks containing up to 30 coal seams. Production is from vertical wells and the coal seam gas production is essentially dry, with no (or very minor) water production. In contrast, the deeper Mannville CBM production involves producing salt water from the coals prior to gas production, although Encana has recently demonstrated that in places good production rates are possible in dry, deep Mannville coals seams.

Although there is a large CBM resources in British Columbia recoverable resources are currently estimated to be small, primarily due to the absence of demonstrated producibility and resource access limitations associated with community and environmental concerns. Stakeholder issues in the Groundhog coalfield in the Bowser Basin and the Fernie Basin in the southeast corner of the province have prevented exploration or development activities to this point in time. Should conditions change in the future, the estimates of recoverable resources for the province should be upgraded accordingly.

There is also a large CBM resources identified in the Maritimes region, primarily offshore Cape Breton Island. A low recovery factor has been assumed for this region to reflect only the onshore opportunities which exist in Nova Scotia.

Table 2.5 Canada's Marketable CBM Resources

Province	Low	High
Alberta	765	3313
British Columbia	113	227
Saskatchewan	<28	<28
Maritimes	85	113
Total	963	3653

Units: BCM

Source: Canadian Society for Unconventional Gas, 2010

The Saskatchewan government has identified a small CBM GIP resource in the province. Any prospect will be modest, and as such the resource has been assigned a low recovery factor, effectively zero potential.

Yukon, NWT, and Nunavut all are believed to have CBM gas in place; however, they have not been included due to the limited information as well as the small potential that they may represent.

(3) Reserves

The Canadian Gas Potential Committee places estimates of CBM in Canada between 5 and 16 TCM. This could potentially be more than conventional gas reserves, which are estimated to be 7 TCM. The Alberta Energy and Utilities Board (EUB) places British Columbia's probable economically recoverable reserves of CBM at 3 TCM, with Alberta being home to the largest share of the resource in Canada with an estimated 4 TCM.

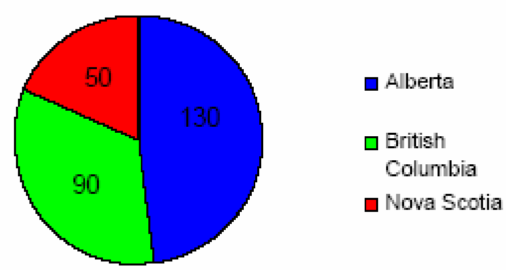


Figure 2.7 Canada's Major CBM Reserves

Source: Alberta Energy and Utilities Board, 2004.

The EUB reports established reserves of traditional natural gas in the Alberta to be 1 TCM. At current development and consumption rates, the province will require nontraditional gas sources by as early as 2008. The same agency reports the in situ amount of CBM resources in the province to be 12 TCM~17 TCM in the Foothills and 10 TCM in the Plains region. The economically recoverable numbers of this resource are estimated to be much lower, between 0 and 4 TCM.

British Columbia's reserves are clearly less voluminous than those of Alberta, however in some areas the government has been more progressive in addressing obstacles to CBM development. One particularly promising location for future development is the sparsely populated Northeast area of the province. There is little community opposition here, one reason why it has become home to the majority of BC's CBM pilots.

2.1.3.2 Main Coalbed Methane Basins in Canada

Coal basins in the conterminous United States and Alaska extend across their borders into Canada. There are 15 coal basins, which stretch from the Canadian west to east coasts and from the southern boundary with conterminous United States to the northwest boundary with Alaska (Figure 2.8). The largest coal basin is the Western Canada Sedimentary Basin (WCSB), which extends from west to east, in the Rocky Mountain Front Ranges and Foothills, and Interior Plains regions of Alberta, British Columbia, Saskatchewan, and Manitoba Provinces, respectively. Southward, the WCSB continues into the north central coal region and Williston Basin in Montana and North Dakota of the conterminous United States. The tectonic setting of the WCSB is similar to that of the Rocky Mountains regions of the United States in that during the Columbian and Laramide Orogenies, a series of thrust sheets buried Cretaceous coal-bearing sedimentary fills in the deep foreland basin resulting in distinct coal characteristics.

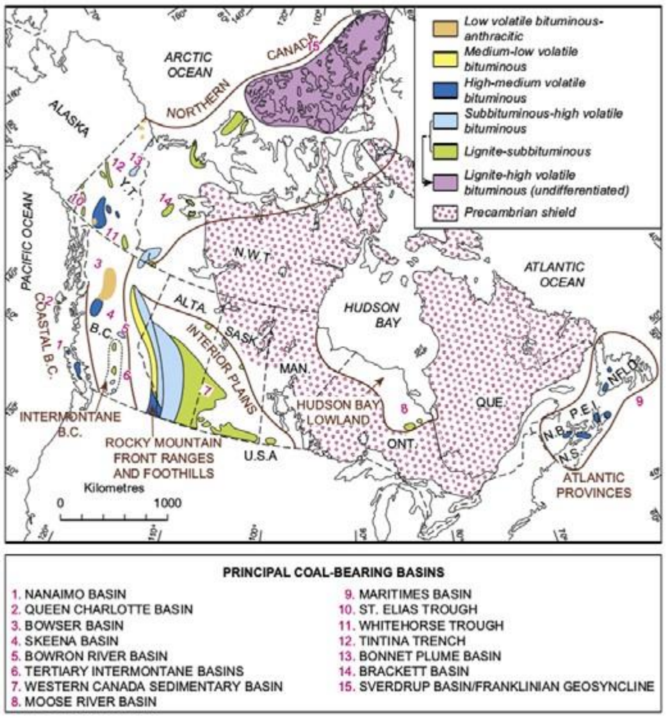


Figure 2.8 Areal distribution and coal rank in coal basins in Canada

Source: Romeo M. Flores, Chapter 9 - Worldwide Coalbed Gas Development, In Coal and Coalbed Gas

There are 13 other smaller coal basins, which extend along the regions of coastal and intermontane British Columbia, northern Canada, and the Hudson Bay Lowland. The northern Canada region extends into the northern and central coal provinces of Alaska. The Atlantic Provinces of New Brunswick, Nova Scotia, and Newfoundland include the Maritimes Basin, which is correlative to the northern Appalachian Basin in the conterminous United States. These Canadian coal basins have inconsequential coalbed methane developments compared to WCSB where commercial coalbed methane development commenced in 2000.

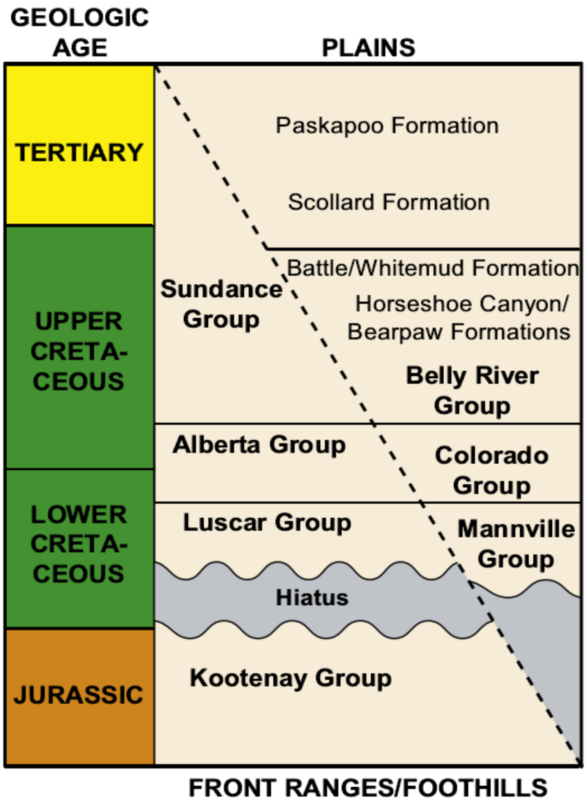


Figure 2.9 Generalized stratigraphic column showing geologic ages of rock units from the Rocky Mountain ranges and foothills to the plains in Western Canada Sedimentary Basin

Source: Romeo M. Flores, Chapter 9 - Worldwide Coalbed Gas Development, In Coal and Coalbed Gas

The coal deposits in the 15 Canadian coal basins occur in strata ranging in age from Devonian to Teriary (Smith, 1989; Smith et al., 1994; Taylor et al.,2008; Vogler, 2006). However, the major targets of exploration and development for coalbed methane are limited to the WCSB, which contains coal zones in the Jurassic to Tertiary (Paleocene) strata. The Jurassic coals in the southern Canadian Rocky Mountains and Foothills have ranks that are high- to low-volatile bituminous with sparse anthracites in the Kootenay Group (Smith et al., 1994). The Early Cretaceous coals in the Rocky Mountain Inner Foothills between the Front Ranges and Interior Plains range from medium- to low-volatile bituminous rank and from high-volatile bituminous to anthracite in the Gates Formation in the Luscar Group (Beaton, 2003; Smithet al, 1994). Early Cretaceous coals in the Mannville Group, which under lies the Interior Plains range from subbituminous to high-volatile bituminous rank in the north and east, and high-volatile bituminous C-A in the central Plains (Beaton, 2003). Coal ranks of

Mannville coals increase with depth westward and these range from medium- to low-volatile bituminous coals. Thus, the regional vertical and lateral variations in coal rank demonstrate the influence of sedimentary and tectonic burial as well as proximity to deformation where folding and faulting might have increased rank.

Also, in the Interior Plains, the Late Cretaceous and Tertiary coals range from high-volatile bituminous to subbituminous and lignite rank. The coal rank increases at depth and toward the Foothills typified by the coal zone in the Upper Cretaceous Horseshoe Canyon Formation, which ranges from subbituminous to high-volatile bituminous (Beaton, 2003; Smith et al., 1994). The Drumheller coal zone in the Horseshoe Canyon Formation ranges from subbituminous B-A at shallow depths to high-volatile bituminous C in the deeper Central Plains region. The coal zone in the Upper Cretaceous-Tertiary Scollard Formation ranges in rank from subbituminous at the outcrop to high-volatile bituminous B at depth in the western Plains.

The Western Canadian Sedimentary Basin (WCSB) is an intracratonic forelan basin, underlying 1,400,000 square kilometres of Western Canada including southwestern Manitoba, southern Saskatchewan, Alberta, northeastern British Columbia and the southwest corner of the Northwest Territories. It consists of a massive wedge of sedimentary rock extending from the Rocky Mountains in the west to the Canadian Shield in the east. This wedge is about 6 kilometres thick under the Rocky Mountains, but thins to zero at its eastern margins. The older part of this basin is an intracratonic basin, but the younger rocks (Cretaceous and younger) accumulated in a foreland basin.

Based on overarching controlling factors of basin depth and deformation, Dawson and Sloan (2001) divided the WCSB, from west to east, into four basin plays:(1) restricted basins (British Columbia), (2) foot-hills and mountain regions (British Columbia and Alberta), (3) deep foreland basin (Alberta and Saskatchewan), and (4) shallow foreland basin (British Columbia, Alberta, and Saskatchewan).

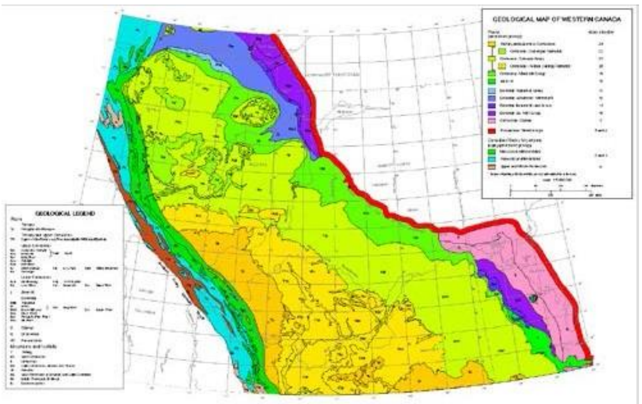


Figure 2.10 Geological map of Western Canada

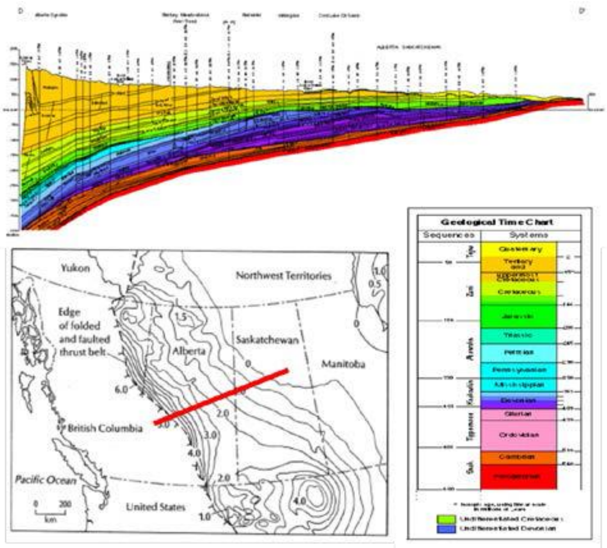


Figure 2.11 Western Canadian Sedimentary Basin section

Source: Alberta Geological Survey

A combination of the coal zone parameters is summarized in Table 2.6 to characterize selected coalbed methane plays in the WCSB. The Scollard, BellyRiver, and part Horseshoe plays are in what are termed by Dawson and Sloan (2001) as shallow foreland basins. Part of the Horseshow and Mannville plays are thought to be within a deep foreland basin (Dawson and Sloan 2001). In all the selected coalbed methane plays discussed in this chapter, coal rank increases with depth (vertical trend) and geographic areas (lateral trend). Mostly coal rank increases toward the west or to the Foothills or to-ward the direction of deformation where the coalbeds dip into the deeper part of the foreland basin. The increase of coal rank at depth and to the west is concomitant with increase of gas content. However, permeability, which conventionally decreases with depth due to overburden pressure, does not appear to be a major factor in the gas content (e.g. Mannville). The Horseshoe Canyon and Mannville coalbed methane plays have permeability up to 10 mD and the highest rate of gas production. However, Gentz is et al. (2008) reported that the Mannville has locally variable permeability ranging from 1 to 4 mD. According to Tayloret al. (2008), the daily production rate is 0.014Bcm mainly from the Horseshoe Canyon (13. MMm^3) and Mannville (2.52 MMm^3).

Table 2.6 Summary of Coal Reservoir Parameters in the WCSB

Coalbed methane Plays (Formation; Group)	**Scollard**	**Horseshoe Canyon**	**Belly River**	**Manville**
Coal Rank (Vertical and Lateral Trends)	Subbituminous to high-volatile bituminous C(lateral trend).Subbituminous to high-volatile bituminous B(vertical trend)	Subbituminous to high-volatile bituminous (lateral trend). Subbituminous B-A to high-volatile bituminous C (vertical trend)	Subbituminous C-B to high-volatile bituminous B(lateral trend).Subbituminous B-A to high-volatile bituminous C(vertical trend)	Subbituminous to high-volatile bituminous (lateral trend).High-volatile bituminous Ce A to medium and low bituminous, anthracite (vertical trend)
Coal Bed Thickness (m)	3-15	1-4	1-3	＜15
Gas Content (cc/g)	0.94-4.06	0.78-2.34		4.68-10.92
Coal Permeability (m D)	＜0.1-7	3-5	1-10	＜0.1-10
Depth (m)	＜750	200-1000	＜750	750-2000

Units: cc/g, cubic centimeter per gram; m D, millidarcy; MMm^3, million cubic meters.

Source: Romeo M. Flores, Chapter 9 - Worldwide Coalbed Gas Development, In Coal and Coalbed Methane

2.1.4 People's Republic of China

2.1.5.1 CBM Resources in China

According to the latest assessment of coalbed methane resources in People's Republic of China (Hereinafter to be referred as China), the coalbed methane in the depth of less than 2,000m is 36.8 trillion cubic meters of which 11 trillion m^3 are recoverable. (Liu Chenglin, Zhu Jie, Che Changbo, Yang Hulin and Fan Mingzhu, 2009).

2.1.5.2 Coalbed Methane Basins and Coalbed Methane Resources in China

According to the latest assessment of coalbed methane resources in China (Liu Chenglin, Zhu Jie, Che Changbo, Yang Hulin and Fan Mingzhu, 2009), there are five gas accumulation regions in Northeast China, North China, Southwest China, South China and Tibetan Plateau, of which the accumulation region of Northeast China includes 11 major basins (e.g. Hailaer Basin, Erlian Basin and Sanjiang-Muling River Basin); North China 11 (e.g. Ordos Basin, Qinshui Basin and Yinshan Basin); Northwest China 5 (e.g. Junggar Basin and Tarim Basin); South China 11 (e.g. Sichuan Basin, Southern Sichuan & Northern Guizhou and Eastern Yunnan & Western Guizhou); and Tibetan Plateau Zhaqu - Mangkang Basin. See Table2.7 for the specific distribution of coalbed methane resources in the major basins:

Table 2.7 Distribution of the Coalbed Methane Resources in Major Basins

Gas Accumulation Regions	**Gas-bearing Basins (Basin)**	**Resources (B m^3)**
Northeast China	Hailaer	1593.6
	Erlian	1964.8
	Sanjiang-MulingRiver	310.3
	Yanbian	2.3
	Dunhua-Fushun	7.7
	Hunjiang-Liaoyang	116.3
	Western Liaoning	14.6
	Jiaohe-Liaoyuan	2.9
	Yilan-Yitong	5.3
	Great Khingan	0.1
	Songliao	3.9
Subtotal		4021.7

North China	Yinshan	100.6
	Ordos	9819.7
	Datong-Ningwu	507.2
	Qinshui	3966.9
	Eastern Foot of Taihang Mountain	431.4
	Northern Hebei	9.1
	Central Hebei	173.3
	Jingtang	141.9
	Northern Henan-Southwestern Shandong	118.1
	Western Henan	674.4
	Xuhuai	578.5
Subtotal		16521
Northwest China	Junggar	3869.8
	Tuha-Santanghu	2714.0
	Tarim	1933.9
	Tianshan	1626.1
	Qaidam	141.2
	Hexi Corridor	117.1
Subtotal		10402.2
South China	Sichuan	604.2
	Central Yunnan	54.9
	Southern Sichuan & Northern Guizhou	952.1

	Eastern Yunnan & Western Guizhou	3472.4
	Central Guangxi	20.2
	Hubei-Jiangxi Border	0.0
	Central Hunan	78.1
	Pingle	36.8
	Lower Reaches of Yangtze River	8.5
	Jiangsu-Zhejiang-Anhui Border	22.1
	Zhejiang-Hubei Border	3.0
Subtotal		5252.3
Tibetan Plateau	Zhaqu - Mangkang	4.4
Subtotal		4.4
Total		36201.6

Source: Liu Chenglin, Zhu Jie, Che Changbo, Yang Hulin and Fan Mingzhu, 2009

2.1.5 Indonesia

Indonesia has abundant CBM resources. The Ministry of Energy and Mineral Resources estimates that the member economy government has CBM reserves of 574Tcf (approximate 12.82 trillion m^3) distributed in 11 basins, which is 2.7 times more than conventional natural gas. An 85% of these basins contain of lignite to subbituminous (low-rank coal) and 15% is bituminous to anthracite (low-rank coal). The Miocene coal deposits in Indonesia have a thicker, deeper, and higher rank of coal than the Powder River Basin has, and therefore Indonesia is expected to have a better resource. (Zhang, 2018)

2.1.6 Mexico

According to the Economic Ministry's mining division, Mexico’s CBM reserves are estimated at between 120 and 210 billion cubic meter and are concentrated in the northern states of Coahuila and Sonora,. It is apparent from the quality of coal that the basins of Coahuila are the most promising sources of CBM because of their relatively high gas contents, moderate permeability, and relatively shallow depth. (GMI, 2015d)

2.1.7 Russia

Russia is estimated to have significant CBM resources – more than 80 trillion m^3 in coal seams, with the Kuzbass basin providing possibly one of the largest CBM resource development opportunities in the world. Gazprom estimates more than 13 trillion m^3 of CBM in Kuzbass, accessible at 1,800~2,000m depth. Another source estimates Kuzbass CBM resources to be 94 billion m^3 in active degasification areas and 120 billion m^3 in areas where degasification is expected to be conducted in the future, for a total of 214 billion m^3. The Pechora basin’s CBM resource is estimated at 2.26~3.40 trillion m^3, but the area’s harsh climate may limit exploitation of this resource. Overall, CBM resource is estimated at 48 trillion m^3. It is estimated that if appropriate technology is deployed and if aneconomic environment favorable for CBM is created, Russia’s CBM production could increase to up to 2 billion m^3 per year. (GMI, 2015a)

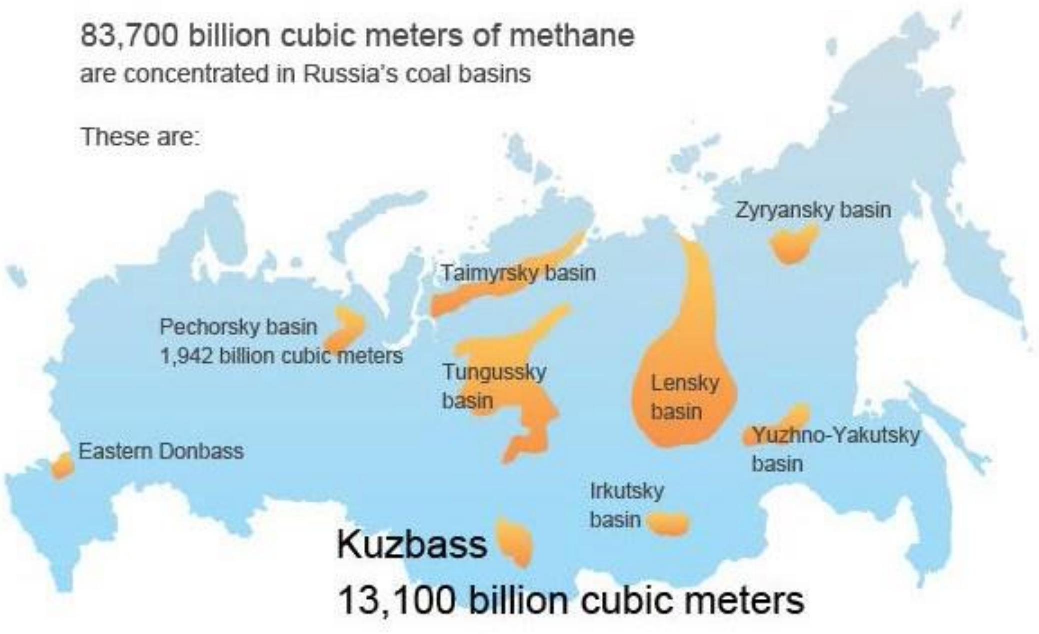


Figure 2.12 CBM Distribution in the Kuzbass Basin in Russia

Source: Gazprom (2014)

2.1.8 United States

2.1.2.1 Coalbed Methane Reserves in United States

According to the statistics of International Energy Agency (IEA) in 2010, CBM resources buried in 2000m underground is 21.4 Tm^3(See Figure 2.13). In the United States, BP and ConocoPhillips are two of the biggest CBM producers in the San Juan basin, where BP has over 1500 wells, while ConocoPhillips has over 800 producing wells (Palmer, 2008). For two comparisons: in the North Appalachian basin, CNX Gas has 2500 small wells in their Virginia plays, while in the Powder River basin (Figure2.14) there are now more than 17,000 producing wells(and 8000 shut-in wells), making a remarkable 1133MMcfd. Proven reserves and production figures reveal almost straight-line growth over the past 15 years (Palmer, 2008). Both reserves and production are almost 10% of total U.S. values, which is a rather significant threshold. One recent estimate is that there are now about 90,000 CBM wells in the U.S.[2]

2 Coal Bed methane completions: A world view

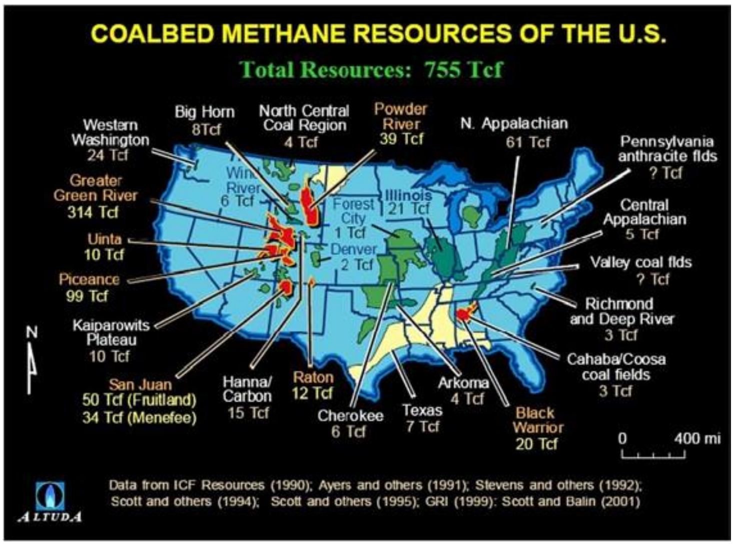


Figure 2.13 Map of U.S. CBM resources

Source: International Journal of Coal Geology, 2010.

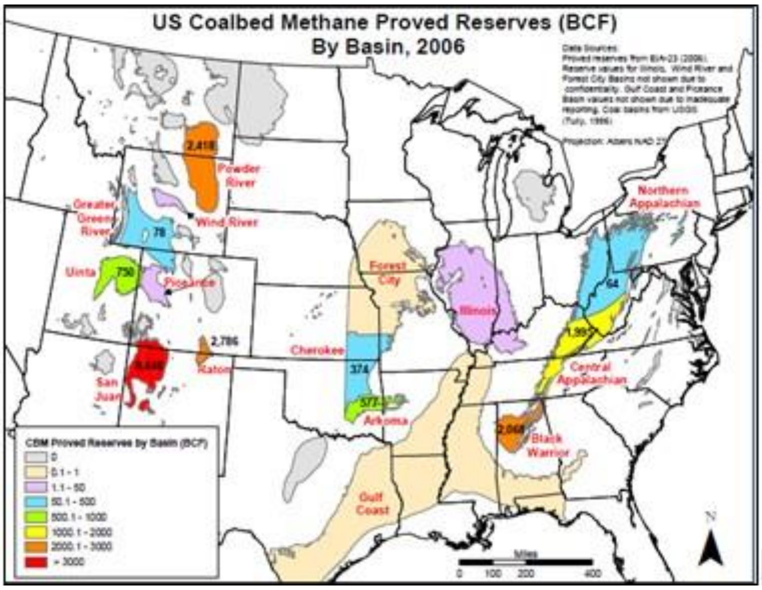


Figure 2.14 Map of U.S. CBM Methane Proved Reserves By Basin

Source: EIA, 2007.

(1)San Juan basin

Gas production is done by vertical, hydraulic fracturing wells. Introduction of a new technology, horizontal boreholes (BH) drilled from the surface with hydrofracking, can increase gas production dramatically. A part of this basin is over-pressurized (gas pressure higher than hydrostatic pressure) leading to very high gas productions.

(2)Piceance basin

The gas content of coal is 400～600 ft^3/t. The coal is of low grade. Permeability is generally low but there are areas where permeability of 15mD is indicated. Gas production is achieved by vertical drilling and hydrofracking. Gas production can be greatly increased by drilling horizontal BH from the surface and hydrofracking.

(3)Powder River basin

The depth of coal seams varies from outcrop to 2500 ft. The gas content of coal seam is low at about 70 ft^3/t. Current CBM production is from a shallow depth of 1000ft or less.

(4)Northern Appalachian Basin

The gas content of coal seams ranges from 100 to 250 ft^3/t.CBM productions is mainly realized by drilling horizontal BH in the coal seam from the surface and in-mine workings. This is the initial production from a freshly drilled BH. The total CBM reserve is 61TCF.

(5)Central and Southern Appalachian Basin

The gas content of coal seam varies from 300 to 700 ft^3/t. Specific CBM production from horizontal BH is 5-10 MCFD/100 ft. The main CBM production technique is vertical drilling with hydrofracking. For commercial gas production, multiple coal seams are hydraulic fractured in a single well. Gas production of 250-500 MCFD is quite common for a single well completed in 3-5 coal seams. The total gas reserve is estimated at 25-30 TCF.

The CBM industry in the United States is well established. Nearly 50,000 wells have been completed with a total annual production of 1.8TCF (about 10% of total US gas production). It can be easily doubled if the new technology of horizontal BH drilled from the surface and hydrofracking is applied to western thick coal seams.[3]

Table 2.8 resources and reserves (Proved reserves) of CBM basins

Main Basins	**Resources (BCM)**	**Reserves($\times 10^7$cubic meters)**
Black Warrior Basin	570	59

3 Global Reserves of Coal Bed Methane and Prominent Coal Basins

San Juan Basin	2380	239
Piceance Basin and Uinta Basin	3090	21
Raton Basin	340	79
Powder River Basin	1100	68
Central Appalachian Basin	140	56
Northern Appalachian Basin	1730	2
Total	9350	524

Source: EPA, 2011

2.1.2.2 Main Coalbed Methane Basins in the United States

(1)The Black Warrior Basin

a. Basin Geology

The Black Warrior Basin is the southernmost of the three basins that compose the Appalachian Coal Region of the eastern United States. The basin covers about 23,000 square miles in Alabama and Mississippi. It is approximately 230 miles long from west to east and approximately 188 miles wide from north to south (Figure 2.15). Basin CBM production is limited to the bituminous coalfields of west-central Alabama, primarily in Jefferson and Tuscaloosa Counties.

b. CBM development

CBM production in the Black Warrior Basin is confined to the Pennsylvanian-aged Pottsville Formation. The ancient coastline of prehistoric Alabama was characterized by 8 to 10“coal-deposition cycles” of rising and falling sea levels. Each cycle features mudstone at the base of the cycle (deeper water) and coal beds at the top (emergence). Most CBM wells tap the Black Creek/Mary Lee/Pratt cycles and range from 350 to 2,500 feet deep (Hold itch, 1990).

CBM production in the Black Warrior Basin is among the highest in the United States. In 1996, about 5,000 CBM wells were permitted in Alabama. In 2000, this number increased to over 5,800 wells (Alabama Oil and Gas Board, 2002). CBM wells have production rates that range from less than 20 to more than 1 million cubic feet per day per well (Alabama Oil and Gas Board, 2002). Between 1980 and 2000, CBM wells in Alabama produced roughly 1.2 trillion cubic feet of gas. According to GTI, annual gas production was 112Bcf in 2000 (GTI, 2002).

Some portions of the Pottsville Formation contain waters that meet the quality criterion of less than 10,000 mg/L TDS for a USDW. According to the Alabama Oil and Gas Board, some waters in the Pottsville Formation do not meet the definition of a USDW and have TDS levels considerably higher than 10,000 mg/L. Early literature indicates that most of the wells in production in the early 1990s have been hydraulically fractured an average of two to six times to achieve acceptable production rates (Hold itch et al., 1988 Hold itch, 1990; Palmer et al., 1993a and 1993b).

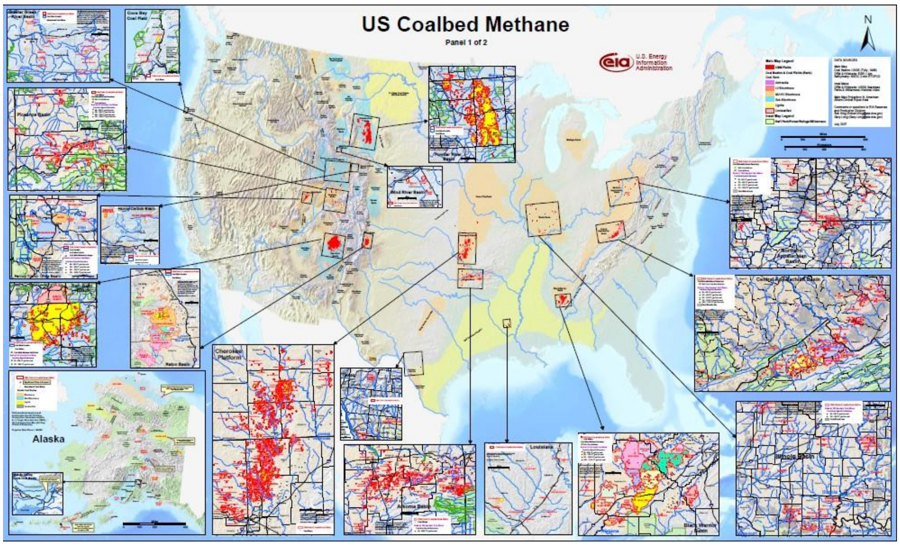


Figure 2.15 Map of CBM Basins with Location[4]

Source:EIA,2013.

[4]US Coal Bed Methane

Figure 2.16 Map of the Black Warrior basin

Source: S. Geology Survey,2015.

(2)The San Juan Basin

a. Basin Geology

The San Juan Basin covers an area of about 7,500 square miles straddling the Colorado-New Mexico state line in the Four Corners region (Figure 2.17). It measures roughly 100 miles long north to south and 90 miles wide. The Continental Divide trends north to south along the eastside of the basin.

b. CBM development

The major coal-bearing unit in the San Juan Basin is known as the Fruitland Formation. CBM production occurs primarily in coals of the Fruitland Formation, but some CBM is trapped in the underlying and adjacent Pictured Cliffs sandstone. Many wells are completed in both zones. The coals of the Fruitland Formation are very thick compared to coal beds in eastern basins: the thickest coals range from 20 to over 40 feet. Total net thickness of all coal beds ranges from 20 to over 80 feet throughout the San Juan Basin, compared to 5 to15 feet in eastern basins.

CBM wells in the San Juan Basin range from 550 to 4,000 feet in depth, and about2,550 wells were operating in 2001 (Colorado Oil and Gas Conservation Commission and New Mexico Oil Conservation Division, 2001). The San Juan Basin is the most productive CBM basin in North America. In 1996, CBM production there averaged about800 thousand cubic feet per day per well and totaled over 800 billion cubic feet for that year (Stevens et al., 1996). This total rose to 925Bcf in 2000 (GTI, 2002).

The majority of CBM development and hydraulic fracturing in the northern portion of the San Juan Basin takes place within a USDW. The waters in parts of the Fruitland Formation usually contain less than 10,000 mg/L TDS, which is the water quality criterion for a USDW. In the northern half of the formation, most waters contain less than 3,000 mg/L, and wells near the outcrop produce water that contains less than 500 mg/L TDS.

Fracturing fluids used in the San Juan Basin include hydrochloric acid; slick water (water mixed with solvent); linear and cross linked gels; and, since 1992, nitrogen- or carbon dioxide-based foams (Harper et al., 1985Jeu et al., 1988; Hold itch et al., 1988; Palmer et al., 1993b; Choate etal., 1993). Data are not readily available concerning fracture growth and height within the Fruit land Formation.

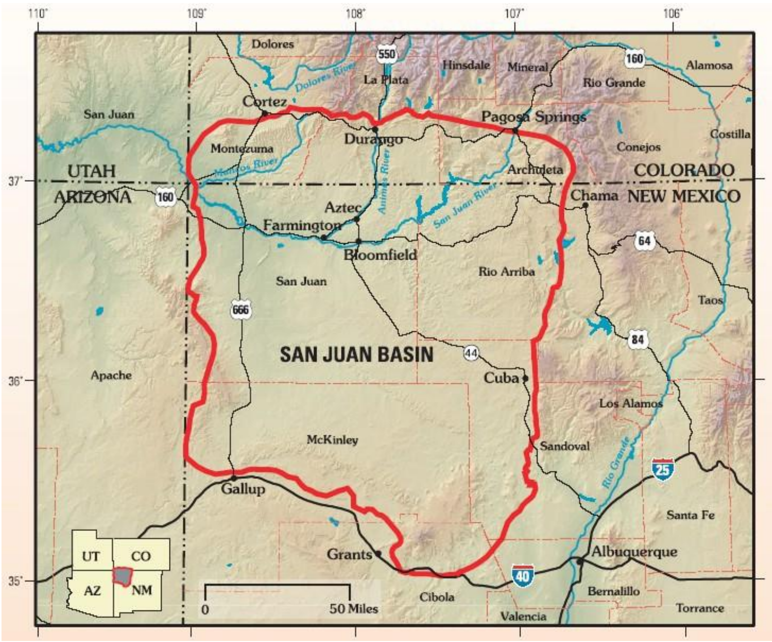


Figure 2.17 Map of the San Juan basin

Source: U.S. Geology Survey,2015.

(3)The Piceance Basin

a. Basin Geology

The Piceance Coal Basin is entirely within the northwest corner of the Colorado (Figure 2.18).The CBM reservoirs are found in the Upper Cretaceous Mesaverde Group, which covers about 7,225 square miles of the basin.

The Mesaverde Group ranges in thickness from about 2,000 feet on the west to about 6,500 feet on the east side of the basin (Johnson, 1989). The depth to the methane-bearing Cameo-Wheeler-Fairfield coal zone is about 6,000 feet. Two-thirds of the CBM occurs in coals deeper than 5,000 feet, and the Piceance Basin is one of the deepest CBM areas in the United States (Quarterly Review, August 1993).

b. CBM development

The depth of the coals in the Piceance Basin inhibits permeability, making it difficult to extract the CBM. This, in turn, has slowed CBM development in the basin. However, it is estimated that 80 trillion to 136Tcf of CBM are contained in the Cameo-Wheeler-Fairfield coal zone of the basin (Tyler et al., 1998). Total CBM production was 1.2Bcf in 2000 (GTI, 2002).The Piceance Basin contains both alluvial and bedrock aquifers. Unconsolidated all vial aquifers (narrow and thin deposits of sand and gravel formed primarily along stream courses) are the most productive aquifers in the Piceance Basin. The bedrock aquifers are known as the upper and lower Piceance Basin aquifer systems. The upper aquifer system is about 700 feet thick, and the lower aquifer system is about 900 feet thick. Water at depth in the Piceance Basin appears to be of poor quality, minimizing its chance of being designated a USDW. In general, the potable water wells in the Piceance Basin extend no further than 200 feet in depth, based on well records maintained by the Colorado Division of Water Resources. A composite water quality sample taken from 4,637 to 5,430 feet deep in the Cameo coal zone exhibited a TDS level of 15,500 mg/L (Graham, 2001).

Hydraulic fracturing is practiced in this basin. A variety of fluids are used for fracturing, including water with sand proppant and gelled water and sand. In some cases, hydraulic stimulations created multiple short (100-foot), fractures around the wells (Quarterly Review, August 1993).It is unlikely that any USDWs and coals targeted for methane production (generally currently located at great depth, such as 4,000 feet below the ground surface and deeper) would coincide in this basin. The thousands of feet of stratigraphic separation between the coal gas bearing Cameo Zone and the lower aquifer system in the Green River Formation should prevent any of the effects from the hydro fracturing of gas-bearing strata from reaching either the upper or the lower bedrock aquifers.

Research suggests that exploration may target areas where groundwater circulation may enhance gas accumulation in the coal and associated sandstones (Tyler et al., 1998). Under these exploration and development conditions, a USDW located in shallower Cretaceous rocks near the margins of the basin could be affected by hydraulic fracturing. The depth of methane bearing coals (about 6,000 feet) seems to indicate that, in the Piceance Basin, the chances of contaminating any overlying, shallower USDWs (no deeper than about 1,000 feet) from injection of hydraulic fracturing fluids and subsequent subsurface fluid transport are minimal. The CBM producing Cameo Zone and the deepest known aquifer, the lower bed rock aquifer, have a stratigraphic separation of over 6,000 feet.

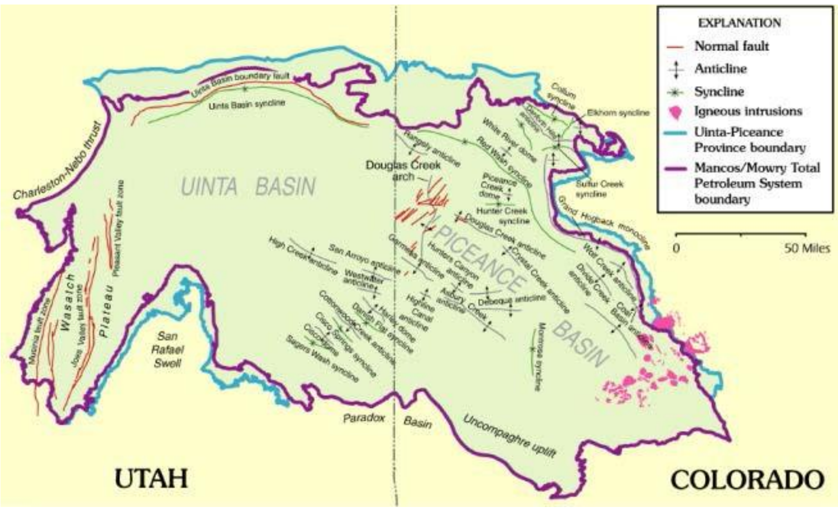


Figure 2.18 Map of the Piceance basin

Source: U.S. Geology Survey,2015.

(4)The Uinta Basin

a. Basin Geology

The Uinta Coal Basin is mostly within eastern Utah; a very small portion of the basin is in northwestern Colorado (Figure 2.19). The basin covers approximately 14,450 square miles (Quarterly Review, August 1993). The Uinta Basin is stratigraphically continuous with the Piceance Basin of Colorado, but is structurally separated from it by the Douglas Creek Arch, an up lift near the Utah–Colorado state line.

b. CBM development

Coal seams occur in the Cretaceous Mancos Shale and the Upper Cretaceous Mesaverde Group (Quarterly Review, 1993). Two major formations targeted for CBM exploration are the Mancos Shale's Ferron Sandstone Member, which include the coals most targeted(approximately 90 percent of the time) for exploration (Petzet, 1996) and the Mesaverde Group's Blackhawk Formation, which contains about 14 coal zones (Petzet, 1996). The Ferron Coals are inter bedded with sandstone and form a wedge of clastic sediment 150 to 750 feet thick. Depths to coal in the Ferron Sandstone range from 1,000 to over 7,000 feet below ground surface (Garrison et al., 1997). The Blackhawk Formation consists of coal seams inter bedded with sandstone and a combination of shale and siltstone. Coals tapped in the Blackhawk Formation are 4,200 to 4,400 feet below the surface (Gloyn and Sommer, 1993).

Full-scale exploration in the Uinta Basin began in the 1990s (Quarterly Review, 1993). The database covering the Uinta Basin indicates that there are about 1,255 CBM wells in production in the basin (Osborne, 2002). The CBM potential of the Uinta Basin, revised by the Utah Geological Survey in the early 1990s, has been estimated to be between 8trillion and more than 10Tcf (Gloyn and Sommer, 1993).

At some locations, the groundwater in the Ferron Coals and Blackhawk Formations would not qualify as USDWs. According to the Utah Department of Natural Resources (DNR), Division of Oil, Gas and Mining, the water there varies greatly by location, each location having some TDS levels below and some above 10,000 mg/L (Utah DNR, 2002). In general, the quality of Blackhawk water is higher than Ferron water. For example, the most recent UIC application noted the combined quality of input water to be approximately 31,000 mg/L TDS for the Drunkards Wash Field and 9,286 mg/L TDS for the Castle gate Field (Blackhawk).

Fracturing fluid use is documented in the literature pertaining to the Uinta Basin. One company reported performing hydraulic fracturing stimulations using cross-linked borate gel with 250,000pounds of proppant (Quarterly Review, 1993). Others report that they fractured wells with low residualfracturing fluids and foams (Quarterly Review, 1993). GTI places the annual CBM production in the Uinta Basin at 75.7Bcf in 2000 (GTI, 2002).

The Blackhawk Formation is underlain by 300 feet of shale and sandstone, which separate it from the Castle gate Sandstone aquifer. It is underlain by similar geologic strata, which separate it from the Star Point Sandstone. Only in highly faulted areas is there a reasonable possibility that hydraulic fracturing fluids could migrate down to the Star Point Sandstone.

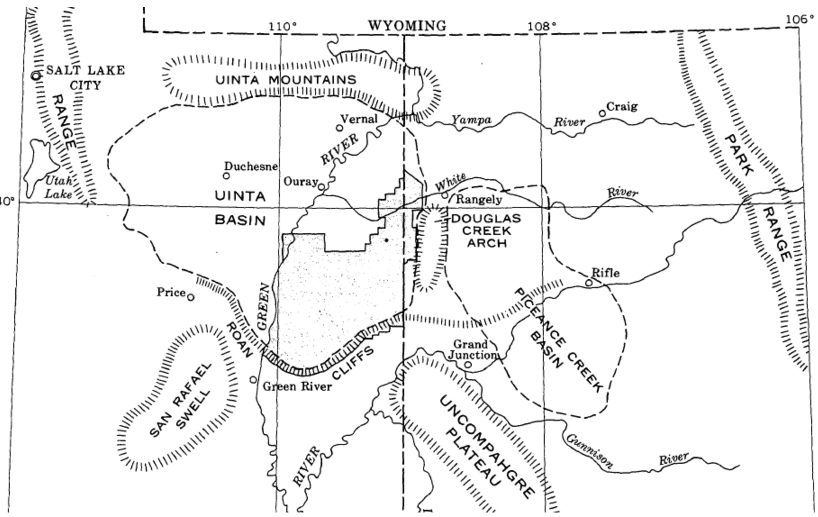


Figure 2.19 Map of the Uinta basin

Source: U.S. Geology Survey,2015.

(5)The Raton Basin

a. Basin Geology

The Raton Basin covers about 2,200 square miles in southeastern Colorado and northeastern New Mexico. It is the southernmost of several major coal-bearing basins along the eastern margin of the Rocky Mountains. The basin extends 80 miles north to south and as much as 50 miles east to west (Stevens et al., 1992). It is an elongate, asymmetric syncline, 20,000 to25,000 feet thick in the deepest part.

There are two major coal formations in the Raton Basin, the Vermejo and the Raton. The Vermejo coals range from 5 to 35 feet thick, while the Raton coal layers range from 10 to more than 140 feet thick. Although the Raton Formation is much thicker and contains more coal than the Vermejo Formation, individual coal seams in the Raton are less continuous and generally thinner.

b. CBM development

Methane resources for the basin have been estimated at approximately 10.2Tcf in the Vermejo and Raton Formations (Stevens et al., 1992). As of 1992, about 114 CBM exploration wells had been drilled in the basin (Quarterly Review, 1993). According to GTI, the average CBM production rate of wells in the Raton Basin was close to 300 thousand cubic feet per day, and annual production in 2000 was 30.8Bcf (GTI, 2002).

The coal seams of the Vermejo and Raton Formations developed for methane production also contain water that meets the criterion for a USDW. The underlying Trinidad Sandstone and other sandstone beds in the Vermejo and Raton Formations, as well as intrusive dikes and sills, also contain water of sufficient quality to be used as drinking water.

CBM well stimulation using hydraulic fracturing techniques is common in the Raton Basin. Records show that fracturing fluids used are typically gels and water with sand proppants. Hemborg (1998) showed that in most cases water yield decreased dramatically as methane production continued over time. However, some wells exhibited increased water production as methane production continued or increased. Two causal factors were suggested (Hemborg, 1998) for the rise in water production:

a). Well stimulation had increased the well’s zone of capture to include adjacent water bearings ills or sandstones that were hydraulically connected to recharge areas, or;

b). Well stimulation had created a connection between the coal seams and the underlying water-bearing Trinidad Sandstone.

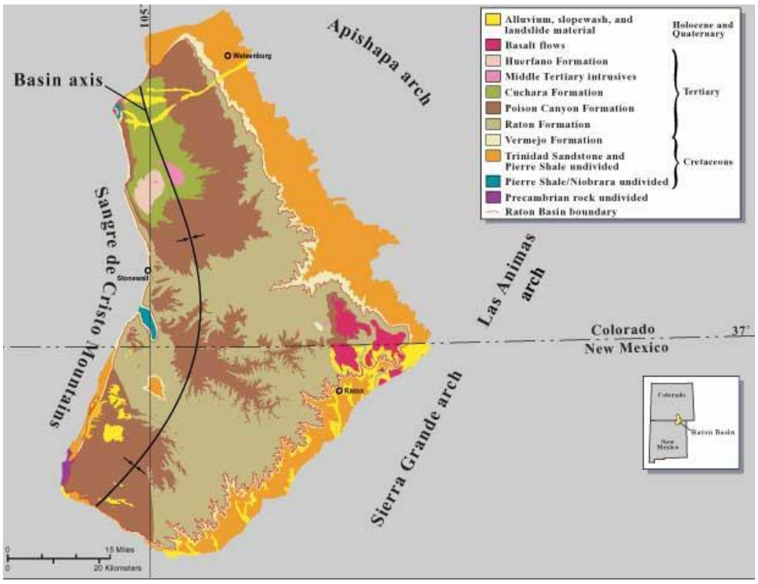


Figure 2.20 Map of the Raton basin

Source: U.S. Geology Survey,2015.

(6)The Powder River basin

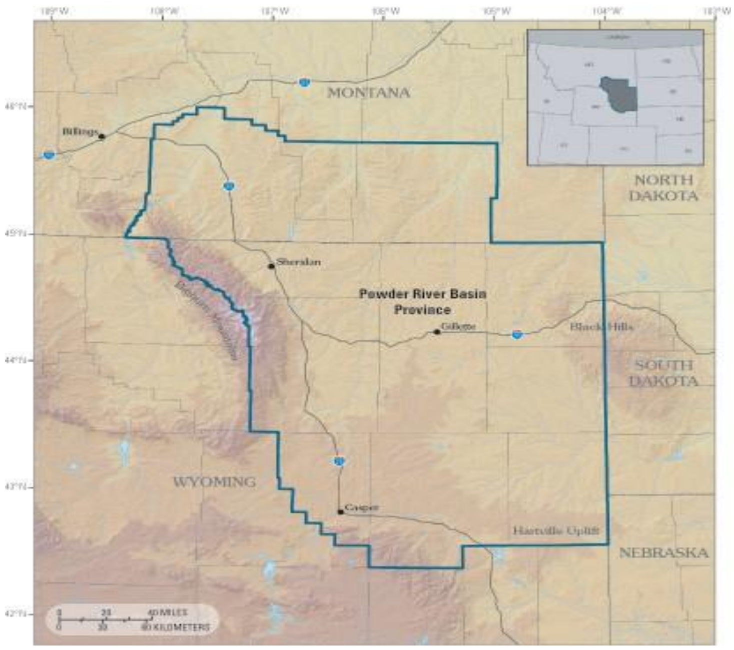


Figure 2.21 Map of the Raton basin

Source: U.S. Geology Survey,2015.

a. Basin Geology

The Powder River Basin is in northeastern Wyoming and southern Montana (Figure 2.21). The basin covers approximately 25,800 square miles (Larsen, 1989), approximately 75 percent of which is in Wyoming. Fifty percent of the Powder River Basin is believed to have the potential for CBM production (Powder River CBM Information Council, 2000).

b. CBM development

Annual production volume was estimated at 147Bcf in 2000 (GTI, 2002). In 2002, wells in the Powder River Basin produced about 823Mcf per day of CBM (DOE, 2002).Coal beds in this region are interspersed at varying depths with sandstones, mud stone, conglomerate, limestone, and shale. The majority of the potentially productive coal zones range from about 450 feet to over 6,500 feet below ground surface (Montgomery, 1999). The uppermost formation is the Wasatch Formation, extending from land surface to 1,000 feet deep.

Most coal seams in the Wasatch Formation are continuous and thin (6 feet or less). The Fort Union Formation lies directly below the Wasatch Formation and can be as much as 6,200 feet thick (Law et al., 1991). The coal beds in this formation are typically most abundant in the upper portion, called the Tongue River member. This member is typically 1,500 to 1,800 feet thick, of which up to a composite total of 350 feet of coal can be found in various beds. The thickest of the individual coal beds is over 200 feet (Flores and Bader, 1999). Recent estimates of CBM reserves in the Powder River Basin range from 7 trillion to 40Tcf (Montgomery, 1999;PRCMIC, 2000).

The Fort Union Formation that supplies municipal water to the City of Gillette is the same formation that contains the coals that are developed for CBM. The coal beds contain and transmit more water than the sandstones. The sandstones and coal beds have been used for the production of both water and CBM. The water produced from the coal beds meets the quality criterion for USDWs of less than 10,000 mg/L TDS.

EPA's understanding is that hydraulic fracturing currently is not widely used in this region due to concerns about the potential for increased groundwater flow into the CBM production wells (due to fracturing of impermeable formations adjacent to the coal, and the creation of a hydraulic connection to adjacent aquifers) and the collapse of open hole wells in coal upon dewatering. According to the available literature, where hydraulic fracturing has been used in this basin, it has not been an effective method for extracting methane. Hydraulic fracturing has been done primarily with water, or gelled water and sand, although recorded use of a solution of potassium chloride was identified in the literature.

(7)The Central Appalachian Basin

The Central Appalachian Coal Basin is the middle of three basins that compose the Appalachian Coal Region of the eastern United States. It includes parts of Kentucky, Tennessee, Virginia, and West Virginia (Figure 2.22) and covers approximately 23,000 square miles. The greatest potential for methane development is in a small, 3,000-square-mile area in southwest Virginia and south central West Virginia (Kelafant, et al., 1988).

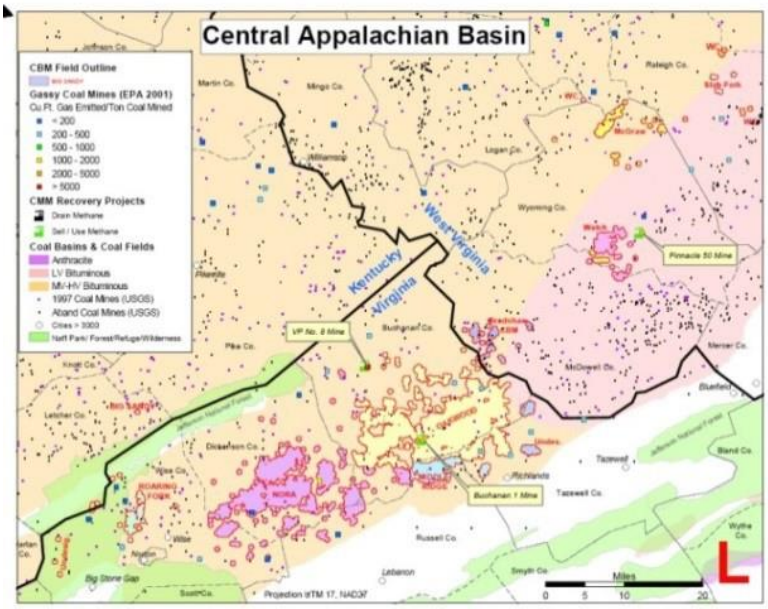


Figure 2.22 Map of the Central Appalachian basin

Source: U.S. Geology Survey,2015.

a. Basin Geology

The coal basin consists of six Pennsylvanian age coal seams (Zebrowitz et al., 1991, and Zuber, 1998). These coal seams typically occur as multiple coal beds or seams that are widely distributed (Zuber, 1998). The coal seams, from oldest to youngest (West Virginia/Virginia name), are the Pocahontas No.3, Pocahontas No.4, Fire Creek/Lower Horsepen, Beckley/War Creek, Sewell/Lower Seaboard, and Iager/Jawbone (Kelafant et al., 1988). The Pocahontas coal seams include the Squire Jim and Nos. 1 to 7; Nos. 3 and 4 are the thickest and cover the most area. Most of the CBM (2.7Tcf) occurs in the Pocahontas seams (Kelafant etal,1988). In southwest Virginia and south central West Virginia, target coal seams achieve their greatest thickness and occur at depths of about 1,000 to 2,000 feet (Kelafant et al., 1988).

The Nora Field in southwestern Virginia is one of the better-known CBM production fields. According to the Virginia Division of Gas and Oil, over 700 CBM wells were drilled in the Nora Field in 2002 (Virginia Division of Gas and Oil, 2002). The Virginia Division of Gas and Oil also indicated that, in 2002, more than 1,800 CBM wells were drilled in southwestern Virginia's Buchanan County (VA Division of Gas and Oil, 2002.)GTI reported that the entire basin produced 52.9Bcf of gas in 2000 (GTI, 2002).

b. CBM development

Because most of the coal strata dip, a CBM well's location in the basin may determine if hydraulic fracturing during the well's development will affect the water quality of surrounding USDW. For instance, on the northeastern side of the basin, the depth to the Pocahontas No. 3 coal bed is less than 500 feet. This depth gradually increases to over 2,000 feet farther westward across this portion of the basin, in the direction of the dip of the coal seam. Therefore, a well tapping this seam in the eastern portion of the basin may be within a USDW, but a well tapping the seam in the western portion of the basin may be below the base of a USDW. In addition, the base of the freshwater is not flat, but rather undulating. These factors indicate that the relationship between a coal bed and a USDW must be determined on a site specific basis.

Hydraulic fracturing is a common practice in this region. Foam and water are the fracturing fluids of choice, and sand serves as the proppant. Additives can include hydrochloric acid, scale inhibitors, and microbicides. Pocahontas Oil & Gas, a subsidiary of Consol Energy, Inc., invited EPA personnel to a well where a hydraulic fracturing treatment was being performed by Halliburton Energy Services, Inc. Halliburton staff said that typical fractures extend from 300 to600 feet from the well bore in either direction, but that fractures have been known to extend from as few as 150 feet to as many as 1,500 feet in length (Halliburton Inc., Virginia Site Visit, 2001).According to the fracturing engineer on-site, fracture widths range from one-eighth of an inch to almost one and one-half inches (Halliburton, Inc., Virginia Site Visit, 2001).

Since some CBM exploration has moved to shallower seams, the Commonwealth of Virginia has instituted a voluntary program concerning depths at which hydraulic fracturing maybe performed (Virginia Division of Oil and Gas, 2002). The program involves an operator’s determination of the elevation of the lowest topographic point and the elevation of the deepest water well within a 1,500-foot radius of any proposed extraction well (Wilson, 2001). Hydraulic fracturing should occur at least 500 feet beneath than the lower of these two points.

(8)The Northern Appalachian Basin

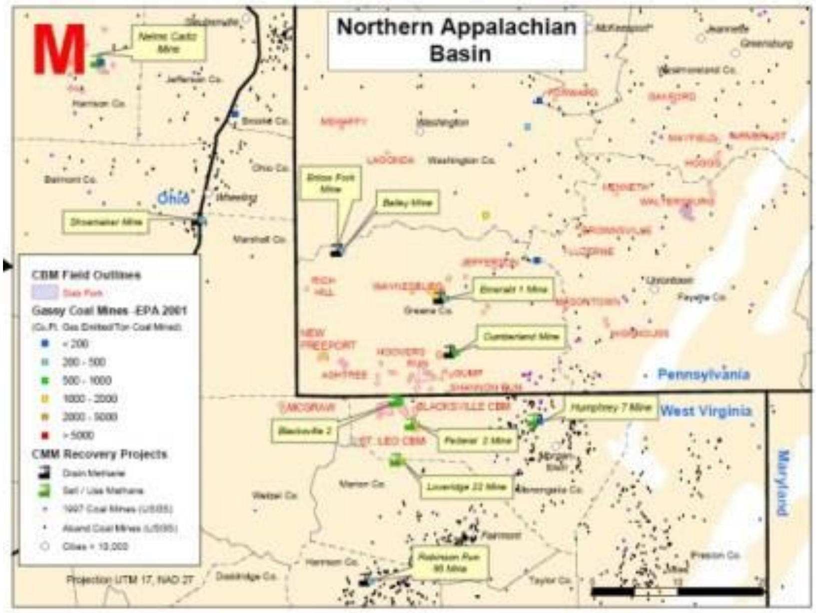


Figure 2.23 Map of the Central Appalachian basin

Source: U.S. Geology Survey,2015.

a. Basin Geology

The Northern Appalachian Coal Basin is the northernmost of the three basins that make up the Appalachian Coal Region of the eastern United States. It includes parts of Pennsylvania, West

Virginia, Ohio, Kentucky, and Maryland. The basin lies completely within the Appalachian Plateau geomorphic province and covers approximately 43,700 square miles (Adams et al., 1984, as cited by Pennsylvania Department of Conservation and Natural Resources, 2002). The Northern Appalachian basin trends northeast to southwest. The Rome Trough, a major graben structure, forms the southeastern and southern structural boundaries. The basin is bounded on the northeast, north, and west by outcropping Pennsylvanian-aged sediments (Kelafant et al., 1988).

The six Pennsylvanian-aged coal zones composing the Northern Appalachian Coal Basin are the Brookville-Clarion, Kittanning, Freeport, Pittsburgh, Sewickley, and Waynesburg. These coal units are within the Pottsville, Allegheny, and the Monongahela Groups (Kelafant et al., 1988).Coal seam depths range from surface outcrops to as much as 2,000 feet below ground surface, with most coal occurring at depths shallower than 1,000 feet (Quarterly Review, 1993). These depth differences arise due to the dip of the coal beds. The total thickness of the Pennsylvanian aged coal system averages 25 feet; however, better developed seams within the coal zones can increase in thickness by up to twice the average (Quarterly Review, 1993).

CBM has been produced in commercial quantities from the Pittsburgh coal bed of the Northern Appalachian Coal Basin since 1932 (Lyons, 1997), after the discovery of the Big Run Field in Wetzel County, West Virginia, in 1905 (Hunt and Steele, 1991). As of 1993, O'Brien Methane Production, Inc. had at least 20 wells in Pennsylvania's southern Indiana County (Quarterly Review, 1993). CBM production development in the Northern Appalachian Basin has lagged, however, due to insufficient reservoir knowledge, inadequate well-completion techniques, and CBM ownership issues revolving around whether the gas is owned by the mineral owner or the oil and gas owner (Zebrowitz et al., 1991).Discharge of produced waters has also proven to be problematic (Lyons, 1997) for CBM field operators in the Northern Appalachian Coal Basin. Total CBM production stood at 1.41Bcf in 2000 (GTI, 2002). As of October 2002, 185 CBM wells were producing CBM in Pennsylvania (Pennsylvania Department of Conservation and Natural Resources, 2002).

The Northern Appalachian Basin is situated in the Appalachian Plateau's physiographic province. The primary aquifer in this area is a Pennsylvanian sandstone aquifer underlain by limestone aquifers (USGS, 1984). Water quality data from eight historic Northern Appalachian Coal Basin projects show that estimated TDS levels ranged from 2,000 to 5,000 mg/L at depths of 500 to 1,025 feet below ground surface (Zebrowitz et al., 1991), well within EPA's water quality criterion of 10,000 mg/L TDS for a USDW (40 CFR §144.3). Depths to the bottoms of the USDWs vary greatly in the basin and are better determined on a site-specific basis.

b. CBM development

Hydraulic fracturing fluids used in the Northern Appalachian Basin have included water and sand, and nitrogen foam and sand (Hunt and Steele, 1991). The Christopher Coal Company/Spindler Wells Project, which took place from 1952 to 1959, stimulated 1 well with 12quarts of nitroglycerin (Hunt and Steele, 1991). In the Vesta Mines Project of Washington County, Pennsylvania, the United States Bureau of Mines used gelled water and sand to complete 5 wells in the Pittsburgh Seam (Hunt and Steele, 1991).

Because most of the coal strata dip, a well's location in a basin determines whether the well is coincident with a USDW. For example, in the Pittsburgh Coal Group in Pennsylvania, the depth to the top of the coal group varies from outcrop to about 1,200 feet in the very southwestern corner of the state (Kelafant et al., 1988). The approximate depth to the bottom of the USDW is 450 feet. Therefore, production wells operating down to approximately 450 feet could potentially be hydraulically connected to the USDW.[5]

2.1.9 Viet Nam

A number of potential areas for CBM development exist in Viet Nam. The Red River Basin is an economically important area of northern Viet Nam. The area has coal deposits lying at depths of 250 to 1,200 meters spread over a 3,500 square kilometer area. Gas content of the basin's sub-bituminous coal is estimated at 0.94~1.6 m3/tonne (30 to 50scf/ton), with

5 Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coal Bed Methane Reservoirs

conservative resource estimates ranging from 170 to 280 billion m^3 (6 to 10Tcf). Another area of interest is the Quang Yen Basin, which extends over 200km from east to west in northeast Viet Nam and covers approximately 5,000km^2. Though yet undetermined, CBM and CMM potential of this area is a target for study. (GMI, 2015b)

2.1.10 Other Economies

Chile's best defined unconventional gas resource is its coalbed methane deposits, which have been explored intermittently for two decades. There are two main CBM areas in Chile. One is the high-rank Arauco Coal Field in central coastal Chile, and the other is the low-rank Magallanes Basin in the Tierra del Fuego region of southern Chile. The Magallanes Basin in southern Chile appears to be Chile's most promising CBM prospect. (APEC, 2013)

Coalbed methane (called coal seam gas (CSG) in New Zealand) exploration began in the 1980s in the Ohai Coalfield and at Greymouth Coalfield on the South Island. Some limited initial appraisals have been conducted by the private sector on the size of New Zealand's CBM resources, estimated at 54 Bcm. Major reserve basins include Taranaki Basin, North Huntly Coalfield and Ohai Coalfield. (APEC, 2013)

2.2 The Status of Coalbed Methane Development

2.2.1 Australia

2.2.1.1 The Status of Coalbed Methane Development in Australia

Australia has sizeable known and inferred reserves of CBM, occurring mainly in the large coal basins of Queensland and New South Wales. Exploration for CBM in Australia has focused on two types: gas associated with shallow coal seams and gas in deep coal formations. Shallow coal seams contain the majority of identified CBM resources. Deep coal gas is being explored for in some basins for example, the Cooper and Galilee basins.

Over the last decade, CBM development in Australia has expanded rapidly, especially in Queensland. Queensland has sedimentary basins ranging in age from Precambrian to Tertiary with a variety of geological settings and histories. Queensland has experienced almost 20 years of CBM development. However, it is only within the last decade that the scale of the industry has increased substantially, due to the establishment of a major LNG industry based on CBM, with proven and probable reserves increasing more than tenfold over the last decade (Figure 2.24 & 2.25).

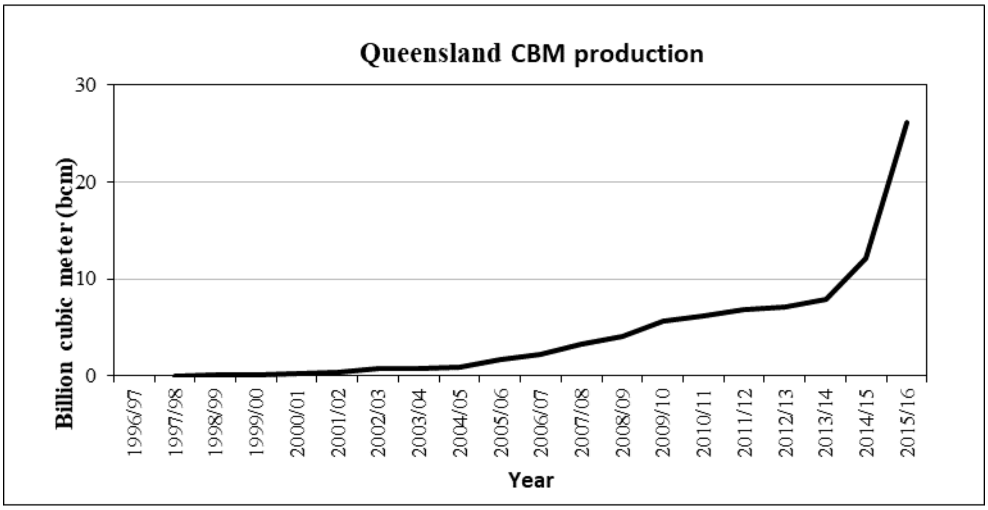


Figure 2.24 Queensland CBM annual production to 30 June 2016

Source: Queensland Government data

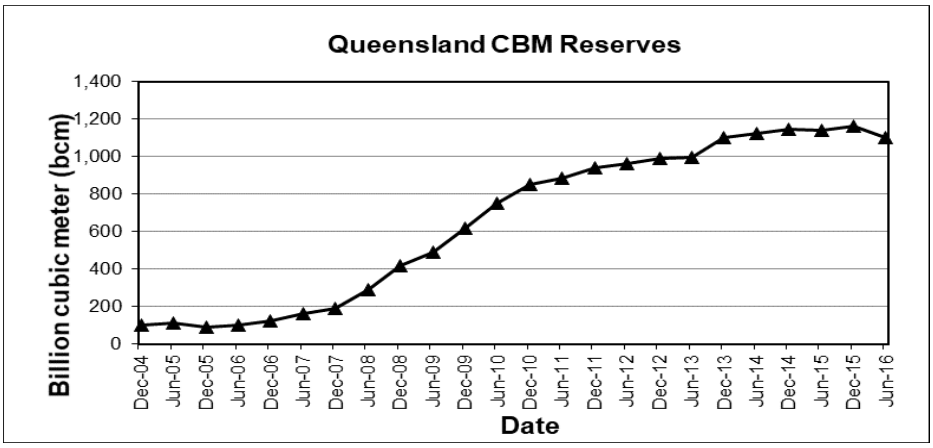


Figure 2.25 Queensland Coalbed methane reserve

Source: Queensland Government data

Queensland has two basins currently producing CBM, the Bowen and Surat basins (Section 2.1.4.2.) A number of other basins have potential and are currently being explored. The Permian to Triassic Bowen Basin is the birthplace of the CBM industry in Queensland. The first commercial production began in the Dawson River CBM area near Moura in 1996 and in the Fairview CBM area near Injune in 1998. Currently, commercial production occurs in the basin near Moranbah, Injune, Moura and Wandoan. The Permian coal measures are the main targets. The Surat Basin became the focus for emerging CSG companies from the early 2000s onwards, when it became clear that an analogue existed with the lower-ranked coals in the Powder River Basin in the United States of America, which were producing commercial quantities of gas.

The development of Australia's CBM reserves contributes to meeting household, commercial and industrial demand in eastern Australia, and supply export markets.

2.2.1.2 Coalbed Methane Production in Australia

In Australia, CBM production was 25.5 BCM (955.3 PJ) in 2015–16. Natural gas production grew by 27 per cent, underpinned by increased Coalbed methane production in Queensland. CBM accounted for almost 30 per cent of gas production and over 60 per cent of eastern market gas production in 2015–16.

Table 2.9 Gas production in Australia

	Conventional Gas	**CBM**	**Total Gas**
2009-10	49.027	6.032	55.643
2010-11	53.480	7.137	61.077
2011-12	50.426	7.116	58.113
2012-13	58.676	7.214	66.457
2013-14	59.968	8.149	68.739
2014-15	59.389	11.380	71.367
2015-16	65.183	25.507	90.690

Units: BCM

Source: Department of the Environment and Energy, Australian Energy Statistics, Table R, August 2017

Table 2.10 CBM production in Australia

	Queensland	**New South Wales**	**Australia**
2009-10	5.863	0.168	6.032
2010-11	6.990	0.147	7.137
2011-12	6.966	0.147	7.116
2012-13	7.076	0.139	7.214
2013-14	8.021	0.128	8.149
2014-15	11.267	0.112	11.380
2015-16	25.352	0.155	25.507

Units: BCM

Source: Department of the Environment and Energy, Australian Energy Statistics, Table R, August 2017

Currently, production of CBM is mainly from the Bowen and Surat basins in Queensland, with some production from the Sydney Basin in New South Wales. CBM production has increased dramatically during the past 15 years. At the end of 2016, CBM production amounted to 28 percent of the total gas production in Australia (Table 2.10). It is expected that CBM production will accelerate quickly with the commencement of three LNG projects: GLNG, APLNG and QCLNG.[6]

2.2.1.3 Coalbed Methane Wells in Australia

The number of CBM wells drilled per annum has increased rapidly over the period, from 10 in the early 1990s to around 200 wells in 2005–06, to over 1,634 wells in 2013–14 and 914 in 2014-15, as shown in Figure 2.26. This activity is expected to decrease once production has been ramped up for the three LNG projects, and plateau at a lower level.

[6] http://www.ga.gov.au/aera/gas

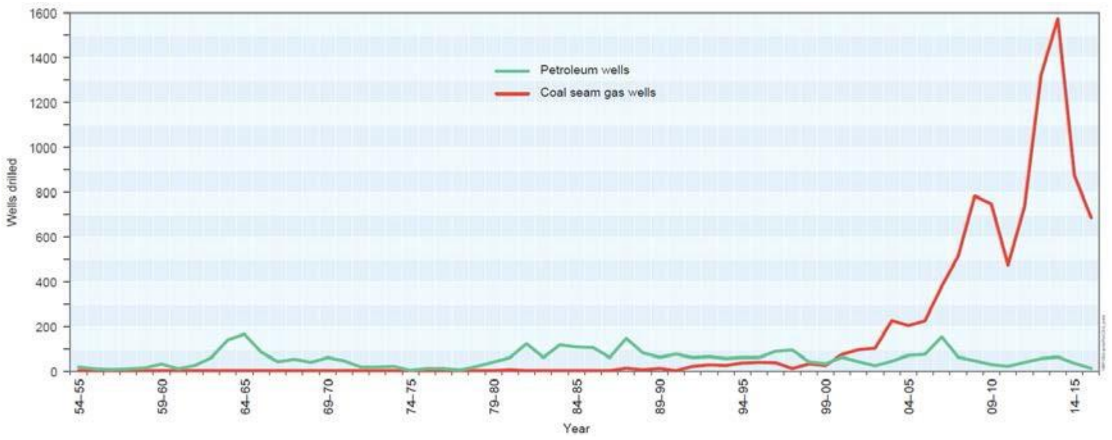


Figure 2.26 Annual Queensland conventional petroleum and CBM wells drilled, to 30 June 2016

Resource: Queensland Government data

2.2.2 Canada

2.2.2.1 The Status of Coalbed Methane Development in Canada

Coalbed methane development in Canada is mainly concentrated in Alberta, British Columbia, and a few in Nova Scotia, Saskatchewan, and Yukon.

Alberta's production for natural gas from coal reservoirs steadily increased, up to 1 billion cubic feet per day (Bcf/day) in 2009 as the new unconventional exploration technology was stimulated by favorable economic factors. Although Alberta's extensive development of CBM attracted numerous exploration companies in the past, in 2014 the production declined to 0.68 bcf/day (AER’s ST98-2015). Nevertheless, the CBM resources are far from exhausted and will remain a secure source of methane, with production depending on economic factors

British Columbia’s natural gas production is transitioning from the conventional natural gas resource base to an emerging unconventional resource base. Up to 60 per cent of B.C.’s gas production stream in 2011 came from unconventional sources such as tight gas and shale gas, according to estimates. By comparison, the province has seen no recent coalbed methane activity.

Nova Scotia, Saskatchewan and the Yukon each have one CBM project underway. The reserve base in these locations is comparatively small, and governments of the respective jurisdictions do not appear as motivated to encourage CBM development as are the governments of Alberta and British Columbia.

2.2.2.2 Coalbed Methane Production in Canada

The major CBM resources in Canada are located in the Mannville, Ardley and Horseshoe Canyon. Following the drilling of over 10500 CBM wells by early 2007, Canada's production exceeded 9 BCM in 2010 (8% of Canada's total gas production). CBM production declines since 2010, with increased production of tight gas and shale gas resulting in an increase in unconventional gas production (Table 2.11, Figure 2.27).

Table 2.11 Unconventional Gas production

Year	2010	2011	2012	2013	2014
CBM	8.906	8.578	8.141	7.705	7.18
Tight Gas	55.48	60.992	63.428	65.864	72.927
Shale gas	1.387	2.409	4.252	6.096	5.935
UG total	65.773	71.978	75.821	79.665	86.041

Units: BCM Source: EIA

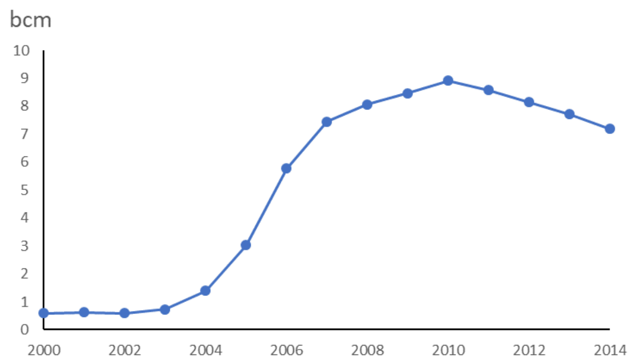


Figure 2.27 CBM Production

Source: EIA

2.2.2.3 Coalbed Methane Wells in Canada

CBM drilling in Canada is concentrated in Alberta. The first Canadian methane production began in 2000 in the Horseshoe Canyon region in Alberta. The Horseshoe Canyon coals are dry and relatively close to the surface, enabling easy gas recovery. Therefore, these fields accounted for 90 percent of the producing wells in Alberta in 2005 (Snyder, 2005), generating more than 2.8 million m^3 per day of methane. Alberta’s CBM production in 2005 totaled 2.5 bcm (Amazouz, 2006). By 2008, there were 6000 wells producing 5.2 bcm per year, all located in Alberta (International, 2008). By 2017, the cumulative number of wells has exceeded 20,000 in Alberta (Figure 2.28). The proportion of new CBM wells in total gas wells has deceased since 2010 (Figure 2.29).

Public data indicate that coal-bed methane wells in British Columbia had 131 wells in 2006.

Figure 2.28 Alberta Marketable CBM Producing Wells

Source: NEB

Figure 2.29 Alberta Marketable Gas Average Daily Production and Producing Wells

2.2.3 People's Republic of China

2.2.3.1 The Status of Coalbed Methane Development in China

By the end of 2016, China's CBM exploration and development had led to a production capacity of 9 billion m^3 as well as accumulative proven geological reserves of 692.8 billion m^3 (see Figure.2.30), including technically recoverable reserves of $3{,}485\times10^8$ m^3 and economically recoverable reserves of $2{,}836\times10^8$ m^3. Two industrial bases of coalbed methane are basically completed in the eastern margin of Qinshui basin and Ordos basin.

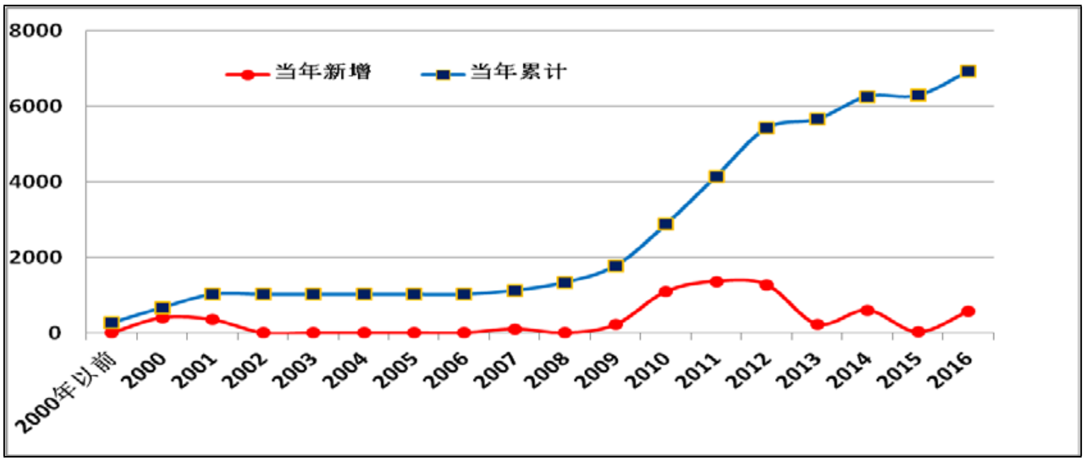


Figure.2.30 Statistical Graph of the Annual Proven Geological Reserves of Coalbed Methane in China

2.2.3.2 Coalbed Methane Production in China

The incomplete statistics shows that China boasts 9 completed coalbed methane development projects (including the commercial development projects in Fanzhuang, Pangani River, Fanzhuang-Zhengzhuang, Zaoyuan, Southern Shizhuang, Sihe-Chengzhuang, Southern Hancheng, Baode and Fuxin) with the production capacity of roughly $48\times10^8m^3/a$, as well as 12 projects under construction with the production capacity of roughly $74\times10^8m^3/a$ including those of PetroChina Huabei Oilfield Company with the production capacity of roughly $30\times10^8m/a^3$ in Zhengzhuang, Northern Zhengzhuang, Mabi and Qinnan-Xiadian; PetroChina Coalbed Methane Company Limited $12\times10^8m^3/a$ Western Hancheng, Linfen and Southern Baode; Petrochina (Zhejiang) Company $4\times10^8m^3/a$ Junlian; China United Coalbed Methane Company $22\times10^8m^3/a$ Southern Shizhuang, Zhangzi, Shouyang, Southern Yanzhu and Liulin; and Petrochina $5\times10^8m^3/a$ Southern Yanchuan.

CBM production was 4.5 billion m^3 and utilization volume was 3.8 billion m^3 in 2016. The annual CBM production and utilization from 2003 to 2016 were shown in the Figure.2.31.

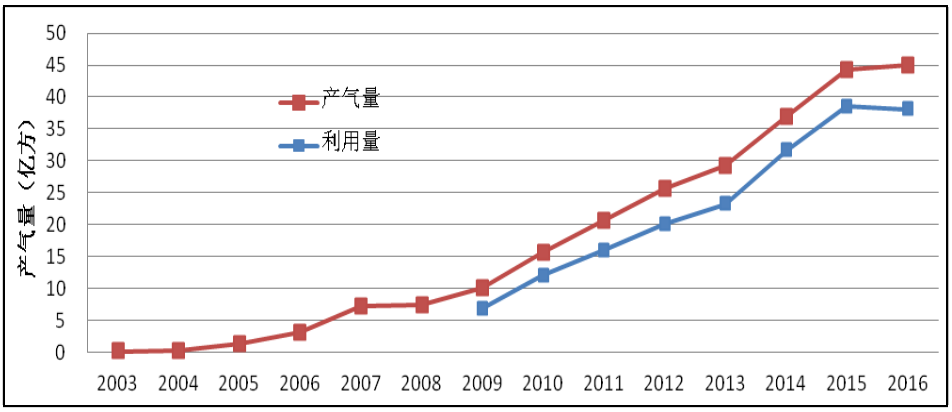


Figure.2.31 The Annual CBM Output and Utilization in China

2.2.3.3 Coalbed Methane Wells in China

During the “12th Fiver-Year” period, the investment ofCBM development increased significantly with roughly 2,530 new coalbed methane wells per year for four years of which 2012 witnessed the strongest annual increase by close to 4,000 new wells. The CBM production of year 2011, 2012, 2013, 2014 and 2015 were $23\times10^8m^3/a$, $25.8\times10^8m^3/a$, $29.8\times10^8m^3/a$, $37.3\times10^8m^3/a$ and $44.25\times10^8m^3/a$ respectively, which were 1.5, 1,8, 2.1, 2.6 and 3.1 times the value of 2010 (see the Figure.2.32).

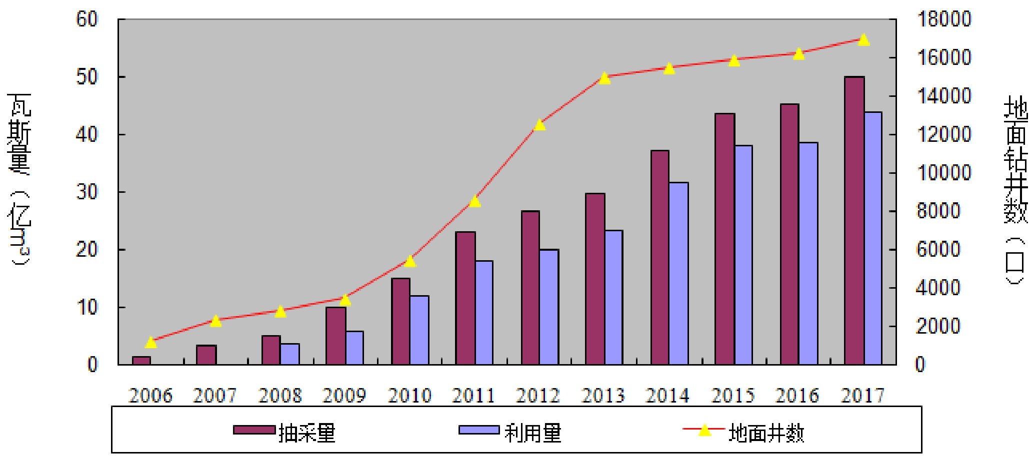


Figure.2.32 Drainage, Utilization and Boreholes of Ground Coalbed Methane from 2016 to 2017

2.2.4 Indonesia

Indonesia’s government promotes exploration of CBM and shale gas, alongside conventional crude oil and natural gas projects. In 2007, the Indonesian government started awarding CBM blocks in the South and Central Sumatra basins on Sumatra Island and the Kutei and Barito basins in East Kalimantan. Recently, there are is six basins, including the South Sumatra Basin, Barito Basin, Kutai Basin, Central Sumatra Basin, North Tarakan Basin and Berau Basin, which are being developed. The Minister of Energy and Mineral Resources authorized the Directorate General of Oil and Gas (MIGAS) to develop CBM in Indonesia.

The Sanga-Sanga CBM block in East Kalimantan was contracted to Virginia Indonesia Co., LLC(VICO), a subsidiary of BP plc., and ENI S.p.A. in November 2009, and commercial CBM production commenced in 2011. CBM from this block is used to generated power, providing electricity for 2,500 homes in Borneo.

Singapore-based Dart Energy and Indonesian PT Energi Pasir Hitam began CBM exploration activities in East Kalimantan in 2013, with the goal of supplying both power plants and the Bontang liquefied natural gas (LNG) facility.

As of 2013, 54 production sharing contracts (PSC) had been signed with the Indonesian government for CBM production. The government anticipates CBM production to reach over 5 billion m^3/a by 2020. (GMI, 2015c).

Figure.2.33 CBM Blocks in Indonesia

Source: CBM Asia (2012a)

2.2.5 Mexico

Until the change in the mining law in 2006, only the state owned oil and gas monopoly, Petróleos Mexicanos (PEMEX) had the right to exploit Mexico’s natural gas resources, including CBM. PEMEX has done several studies on the potential of CBM in the Sabinas Basin region, but their data are not publically available. They have invested little in CBM extraction, focusing on their core business of oil and conventional gas extraction (Barclay, 2006). The major coal companies had little incentive to research CBM drilling prior to 2006 focusing instead on CMM emissions. MINOSA has done significant research regarding the potential of CMM in the Sabinas Basin and appears, at this time, to be following up on potential CMM projects rather than ones involving CBM extraction. (GMI, 2015d)

The Mexican government has recently proposed new regulations for the oil and gas industry which are intended to further liberalize the sector and promote private investment and development. The passage of this new legislation should provide added incentives for CMM and CBM development. (GMI, 2015d)

2.2.6 Russia

Between 2008 and 2009, Gazprom initiated a pilot operation at eight exploratory wells in Taldinskoye field in the Kuzbaas basin and by 2010, and the recovered CBM was being supplied to gas filling stations. In 2011, the daily gas production from the Taldinskaya area totaled 20,000 m^3, and Gazprom aims to reach 4.0 billion m^3 of CBM production from expanded operations by 2021. Two CBM-fired reciprocating-engine power plants have also been commissioned at the Taldinskoye field, which make it possible to supply electricity to the Taldinsky coal strip mine. In February 2012, the Central Commission for Hydrocarbon Fields Development under the Federal Subsurface Use Agency approved the Development Plan by Gazprom Promgaz for the pilot commercial development of the southeastern part of the Taldinskoye CBM field.(GMI, 2015a)

2.2.7 United States

As can be seen from the below table 2.12 and Fig 2.34, the production of CBM in the United States from 1990 to 2016.

Table 2.12 The United States CBM production from 1990 to 2016

Year	**Production (Bcm)**
1990	5.6
1991	9.9
1992	15.3
1993	21.3
1994	24.1
1995	27.1
1996	28.4
1997	30.9
1998	33.8
1999	35.5
2000	39.0
2001	44.2
2002	45.7
2003	45.3
2004	48.7
2005	49.0
2006	49.8
2007	49.6
2008	55.7
2009	54.2
2010	53.4
2011	49.9
2012	46.9
2013	41.5
2014	39.8
2015	35.9
2016	28.9

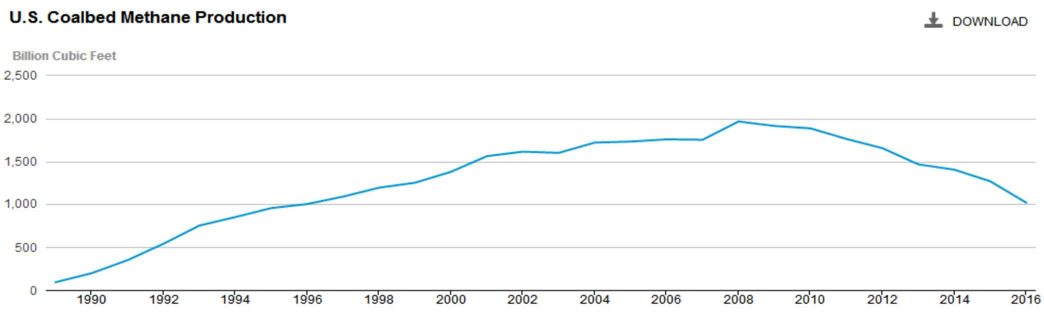


Figure 2.34 The United States CBM production from 1990 to 2016

2.2.8 Viet Nam

Most of Viet Nam's CBM activity to date has been confined to the Red River Basin. Keeper Resources worked on the first CBM exploration projects. A negotiated CBM concession with PetroViet Nam and PetroViet Nam Exploration Production Corporation (PVEP) covered approximately 3,600 km^2 of the Red River Basin to the southeast of Hanoi. Three years of negotiations were concluded with the signing of a CBM Production Sharing Contract (PSC) in early 2010. The preliminary field desorption testing results determined that the coals were under-saturated with no significant quantities of methane reported and further test wells were cancelled. The PSC was relinquished in April of 2012.

Arrow Energy signed a PSC with PVEP in a CBM concession block of 2,610 km^2 in the Red River Basin, referred to as the Hanoi Trough. Arrow, now Dart Energy Ltd., holds a 70 percent interest in the block with a subsidiary of PetroViet Nam holding the remaining 30 percent. The block is in the vicinity of the Tien Hai-Thai Binh industrial area and approximately 150km southeast of Hanoi. In 2009, Dart Energy completed Phase 1 of an initial eight-well exploration drilling campaign. Results from two wells indicated increasing gas volumes at depth. In 2010, Dart Energy commenced a second phase of exploration drilling. The Hanoi Trough block currently has 22.7 billion m^3 of gross original gas in place (OGIP) and 7.1 billion m^3 of gross 2C resource, as certified by Netherland, Sewell & Associates Inc.(GMI, 2015b)

2.2.9 Other Economies

Chile's coalbed methane deposits have been explored intermittently for two decades. Chile's oil and gas company ENAP, which has drilled several coalbed methane appraisal wells in the Magallanes Basin, has been the main explorer, along with several small operators based in North America. (APEC, 2013)

Coalbed methane production in New Zealand is relatively low. Currently, eight companies are active in CSG exploration, holding 17 petroleum permits. (APEC, 2013)

3. Advanced Technology CBM Development in APEC Economies

3.1 CBM Well Types

Drilling types in the ground CBM development pattern mainly include: vertical well, horizontal well, multi-branch horizontal well, U-shape well, L-shape well, etc.

3.1.1 Vertical Well

3.1.1.1 Characteristics

The vertical well technology is most extensively applied and the most mature technology currently, and selected by CBM exploration, development test and CBM development. Cluster well is a kind of drilling mode suitable to complex ground conditions. A group of different underground wells are drilled from the same well site or platform, i.e. inclined shafts are drilled on one well site along different directions. According to topographic conditions, 2~5 inclined shafts can be drilled on one well site. Like vertical well, the inclined shaft can be used to carry out fracturing transformation to reservoirs.

Vertical well and cluster well adopt secondary drilling well structure mode. In primary drilling, use Φ311.2mm drill bit to drill into bed rock, and put down Φ244.5mm casing cementing deep to 10~20m of hard base rock; in the secondary drilling, use Φ215.9mm drill bit to drill 50~60m below coal bed, and put down Φ139.7mm casing cementing after completion.

3.1.1.2 Advantages and disadvantages

(1) Advantages

Both vertical well and cluster well adopt water source drilling rig and light truck-mounted drilling rig. The equipment is simple and feasible, and meets requirements of drilling safety and development. The technical difficulty is small. The cluster well can effectively avoid sections such as buildings, high mountains, reservoir, villages and forest zone which are not allowed to construct on ground. It is superior in drilling multiple target strata, and meeting multi-layer development demands so as to reduce large amount pre-drilling expenses and handling fee, save land, protect environment and greatly reduce land acquisition expenses. It helps unified maintenance of fracturing and drainage, greatly reduces well site quantity, floor area, ground engineering investment and operating expenses, and realizes low cost.

(2) Disadvantages

Both vertical well and cluster well require higher for reservoir permeability. Single well output is always low in section with worse fracture development and low permeability. Meanwhile, single-well control area of vertical well is small, well density is large, and requirement for ground conditions is high. It is better to deploy vertical well in sections with flat surface, convenient traffic and shallow burial depth.

3.1.2 Horizontal Well

3.1.2.1 .1 Characteristics

Horizontal wells can cover more area in a laterally extensive formation than a vertical well can, as multiple horizontal legs can be drilled from one well pad. The well is drilled vertically and then deviates to horizontal at the kickoff point (KOP) into the target formation. The total well length can be up to 4000 meters.

3.1.2.2Advantages and disadvantages

Horizontal wells have been reported to produce gas rates up to 10 times more than vertical wells drilled in the same coal seams, with the average being 4~5 times. In spite of this great advantage, horizontal wells are 2~3 times more expensive to drill or more, depending on depth.

3.1.2.3 .3 Case Study

A vertical well was drilled in 2002 using a polycrystalline diamond compact bit in the Oberlin area (05-10-38-21W4), central Alberta Basin. The well intersected the thick Medicine River (MR) coal seam of the Lower cretaceous Manville Group. At this location, the MR seam was encountered at a true vertical depth of 1,315 m. A 2-m (6-ft) wide cavity was created around the vertical well with a specialty tool. A second well (referred to as the articulate well) was spud at a later date about 150 m away from the first well. The articulate well was drilled initially as a vertical well before becoming deviated and landing horizontally in the MR coal seam. The horizontal well intersected the previously cut 6-ft-wide cavity using directional drilling technology. In-seam drilling continued beyond the cavity intersection and every effort was made to remain in the seam with the use of a gamma-ray tool located behind the drill bit. Brine water (9% NaCl) having a density of 1,080–1,150 kg/m^3 was used to drill the horizontal well. The above mud density resulted in overbalanced drilling conditions at the reservoir depth. A centrifuge was used to remove the coal cuttings generated by drilling and maintaining the drilling fluid density at 1,080 kg/m^3.

Drilling horizontally beyond the cavity intersection proceeded smoothly and the best drilling rate achieved was 590 m per day. Up to this point, everything related to the drilling process was uneventful. In an effort to achieve underbalanced conditions in order to avoid damaging the coal's permeability, air was injected while drilling. Air injection was initiated through the vertical well while the drill bit in the horizontal well was at 2,181 m (total distance that includes the vertical part of the articulate well, the "turn" from vertical to horizontal plus the horizontal length itself). Problems started to appear almost as soon as air was injected. The well unloaded and a large gas flare was produced, in conjunction with lost circulation of the drilling fluid. After many hours of attempting to regain circulation through a combination of air and mud weight adjustments, the well was unloaded again. Massive gas surges and a large high-pressure flare were noticed.

3.1.3 Multi-lateral Horizontal Well

3.1.3.1 .1 Characteristics

Multi-lateral horizontal well is a kind of integrated technology, and can effectively enlarge connecting channel between borehole and coal cleat, and improve flow conductivity; effectively enlarge contact area between borehole and coal seam, increase differential pressure and gas desorption scope, and maximally break pressure balance status in coal reservoir so as o effectively improve CBM extraction rate and recovery efficiency.

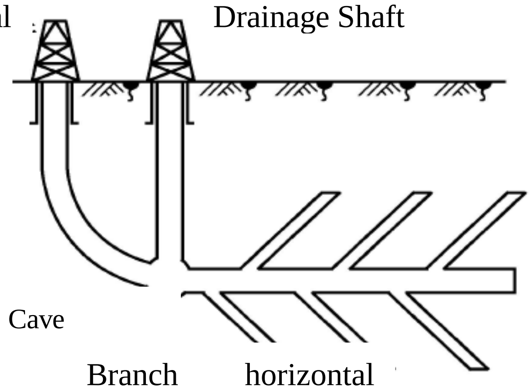


Figure 3.1 Sketch map of CBM multi-lateral horizontal well

3.1.3.2 Advantages and disadvantages

(1) Advantages

The cumulative gas production or recovery factors are determined by the drainage volume or control area of the wells. The control area of a single horizontal well (3280.84 ft. (1000 m) length) is 0.28 sq.mi (0.723 km^2), with its lateral drainage dimension up to 853.02ft. (260 m). For the multi-lateral horizontal well (with main horizontal section length of 3280.84ft(1000 m), branch length of 656.17 ft. (200 m) and angle of 45°) the drainage area increases to 0.38 sq.mi (0.992 km^2) and its lateral extension up to 1312.34ft(400 m).

The multi-lateral horizontal well is not restricted by topographic conditions. Since multi-lateral horizontal well extends longer underground, ground wells are few, and covering area is little, requirements for ground conditions are not high. Compared with conventional vertical well, the multi-lateral horizontal well has the following advantages: a) it improves flow conductivity and has small flow resistance in horizontal well; b) it enlarges coal seam analysis area, connects more cracks and cleats so as to enlarge supply scope of CBM; and c) it is with high single well output (usually as 20 times as that of vertical well), fast fund recover and better economic benefits. Although multi-lateral horizontal well has higher cost, it greatly reduces wells drilled and saves pre-drilling engineering expenses. The economic benefits are favorable.

(2) Disadvantages

The multi- lateral horizontal well can acquire higher single well CBM output. However, the construction process is complex, technical difficulty is large, and requirement for mechanical strength of coal is high so as to guarantee stability of well. In general, it is applicable to coal seam with perfect primary structure. Moreover, cost of multi- lateral horizontal well is far higher than that of vertical well.

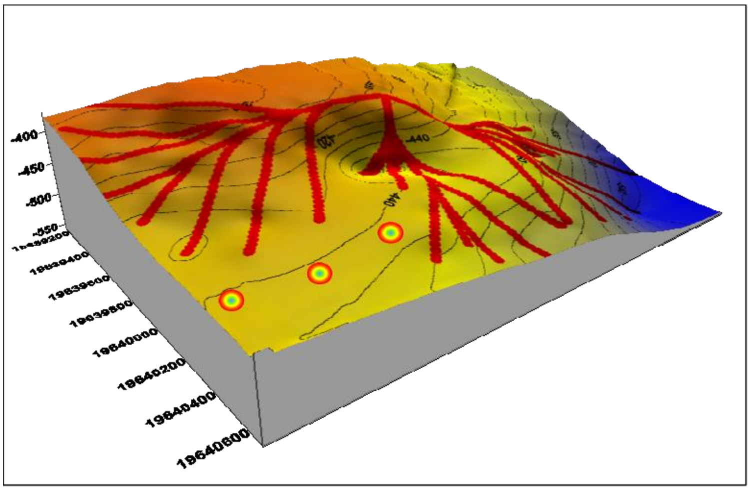


Figure 3.2 Development well pattern: horizontal well + vertical well

3.1.2.3 Successful case

In November 2004, China's (DNP02) CBM multi-lateral horizontal well designed and organized to be constructed by Orion Company was officially put into operation, total footage of horizontal borehole in the coal seam reached 8000m, with the daily single-well yield stabilized above $2\times10^4m^3$, realizing double breakthroughs in CBM development technology and production capacity. By the end of 2010, the construction of more than 60 multi- lateral horizontal wells in Qinshui Basin had been completed. Of them Asian American Coal Inc has finished 9 multi-lateral horizontal wells in Daning and Panzhuang well fields. It took half a year to complete drainage and commence production, and one of the wells broke through $9\times10^4m^3$ daily production. In Duanshi and Panhe demonstration projects of China United Coalbed Methane Corporation, 4 multi-lateral horizontal wells were successfully implemented in the coal No.3 and coal No.15. It was estimated that the single-well daily production capacity is over $2\times10^4m^3$, firstly creating the record of multi-lateral horizontal drilling with two main branches. The footage of PetroChina's M1-1 multi-lateral horizontal well is 6088m in the coal seam. Asian American Gas Incorporation firstly achieved the horizontal directed drilling record of total footage of 9000m in Daning PSC project. Far East Energy Company constructed 3 multi-lateral horizontal wells in Shouyang area. The successful application of multi-lateral horizontal well technology in the CBM development field in Qinshui Basin has provided a new technical way for the CBM development of such basin and coal beds of other area with low permeability.

3.1.4 U-shape well

U-shape well is the U-shape horizontal connected well as Figure 3.3. The CBM U-shape horizontal connected well technology has integrated such technologies of the connection of horizontal well and cave well, unbalanced drilling well and geo-steering, featuring complicated techniques and difficult construction. The gas production efficiency of the U-shape well technology is equivalent to that of the single-branch horizontal well and cave well, suitable for high gas-bearing areas featured with medium or low permeability, medium and high coal rank, large gas content, water-free surrounding rocks in the coal reservoir and stable structure. Such well type is especially applied to the two kinds of coal reservoirs: one is the reservoir with a relatively large water content, which can guarantee the synchronous implementation of horizontal well drainage and vertical cave well gas production; the other is the reservoir with one relative development in either face cleat or bull cleat, with the horizontal well vertical to the relatively developed cleat direction, playing the largest role in connection. At present, the U-shape well technology has been applied to 40-odd wells in China, with a poor effect. The daily gas yield in SJX-1 well through sectional fracturing reached the maximum $5015m^3$, accumulating the gas production of 1.5 million m^3. Technology of horizontal segment casing cementing, non-cementing and glass reinforced plastic pipe were successful. Gas production was related to permeability. In the area with high permeability ($1.0\text{-}3.6\times10^{-3}um^2$) gas production was high, such as daily single-well gas production in Binchang and Shihe could reach 15,000 to 23,000 m^3.

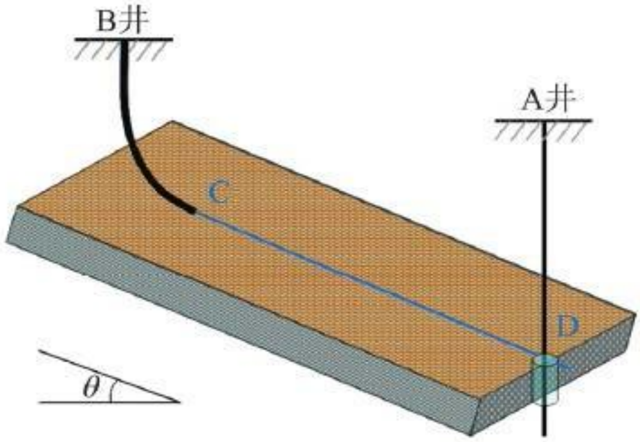


Figure 3.3 Schematic Diagram of U-Shape CBM Well

3.2 Drilling Technology of Coalbed Methane Well

3.2.1 Vertical Well

3.2.1.1 Characteristics

(1) Vertical well, open-hole and under-ream completion, single seam

This drilling and completion technology was pioneered in the Powder River Basin. The major steps for this drilling and completion technology are: a) drilling the production hole to the top of the coal seam; b) running and cementing casing; c) drilling a hole through the coal seam; and d) increasing the diameter of the hole by a technology known as under-reaming. This process is illustrated in Figure 3.4. The resulting hole diameter after under-reaming may be as large as 4 feet. From a reservoir engineering perspective, the stimulation effect is achieved because the resulting under-reamed hole diameter is larger than the original hole diameter. In addition to under-reaming, small high rate water injection into the coal seam may be utilized to open up and relax the surrounding coal cleat system providing additional stimulation.

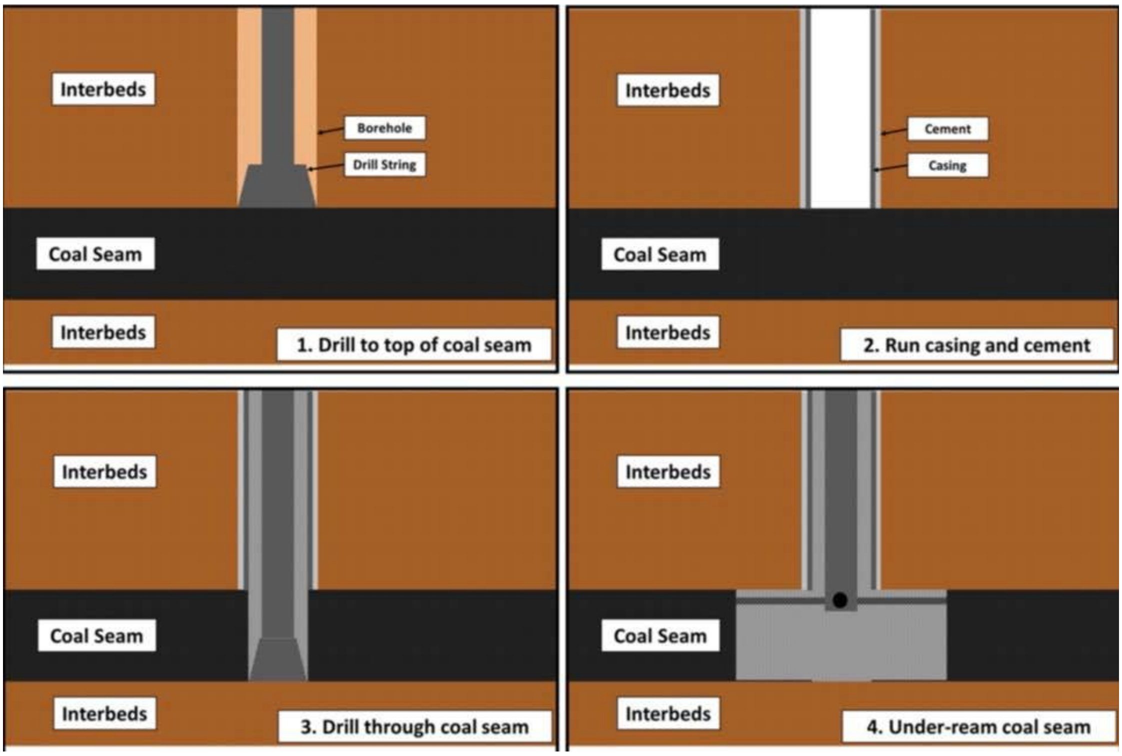


Figure 3.4 Vertical Open-hole Under-ream Completion

Source: J. Caballero. 2013

This type of drilling and completion technology has been used extensively in the Powder River Basin, the San Juan Basin, and has been attempted in other areas.

Figure 3.5 illustrates an example of a simple under-reaming tool. The under-reaming tool works by rotating the drill pipe. High rotation speed causes the “wings” of the tool to swing out by centrifugal force so they can cut into the coal formation. Fluid is circulated during the process in order to lift the coal cuttings as they form. There are many different varieties of under reaming tools and they all share the characteristic of a low cost low technology.

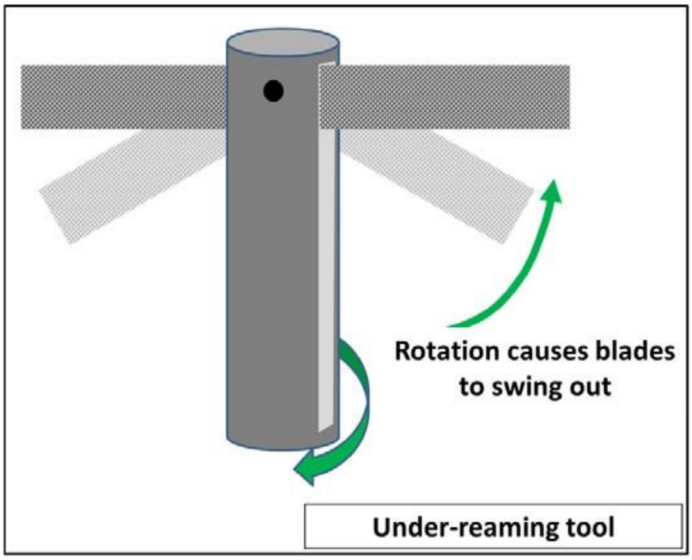


Figure 3.5 Illustration of an Under-reaming Tool

Source: J. Caballero. 2013

(2) Vertical well, open-hole cavity completion, single Seam

Open-hole completions in coal are not a new idea; in fact, the technique has been used in coal reservoirs for many years.(Logan, T. L., Clark, W. F., Mc Bane, R. A. 1989) For example, one of the first true attempts to complete Fruitland Formation coal seams in the San Juan Basin was in 1953, by Stanolind Oil and Gas Company (now Amoco Production Company). In this well, a 73.5 m (241 foot) interval was completed open-hole. The well produced gas at an initial rate of 129,000 m^3/day (4,500 Mscf/day).(Dugan, T. A., Williams, B. L. 1988) Numerous coal wells were completed open-hole by Stanolind, Phillips, and others during the early 1950's. However, little attention was paid to Fruitland coal gas production until Amoco completed the Cahn No. 1 well in 1977 with open-hole techniques. The open-hole interval in this well was under-reamed and the coals were allowed to slough into the wellbore resulting in an enlarged wellbore. After completion, the Cahn No.1 well produced gas at a rate of 57,000 m^3/day(2,000 Mscf/day). In 1986, Meridian Oil began using similar open-hole completion techniques in the San Juan Basin by allowing the coal seams to slough into the wellbore. Numerous operators now use the dynamic open-hole completion technique in lieu of hydraulic fracture stimulation. In some areas of the San Juan Basin, the average gas production rate from dynamic open-hole completed wells exceeds 143,000 seams to slough into the wellbore. Numerous operators now use the dynamic open-hole completion technique in lieu of hydraulic fracture stimulation. In some areas of the San Juan Basin, the average gas production rate from dynamic open-hole completed wells exceeds 143,000 m3/day (5,000 Mscf/day) /day (5,000 Mscf/day).

The open-hole cavity completion technology was first pioneered by Meridian Oil in 1986. (Matthew J. Mavor.1992) This drilling and completion technology is similar to the vertical well open-hole single seam under-ream completion in that a hole is drilled to the top of the coal seam where 7 in. casing is run and cemented (T.L. Logan 1989). After the coal seam is drilled, instead of performing the under-ream technology, air compressors are used to inject air (and sometimes water and air) into the coal seam at high rate and pressure. After injection, the well is opened to the atmosphere and the high pressure air is allowed to escape from the coal seam. This process causes individual pieces of coal to cave into the wellbore, after which they are circulated out of the well bore. This process is repeated many times (typically perhaps 15 times or more). The latter injection cycles cause less coal to cave than the earlier cycles, and cuttings returns are monitored to determine when injection cycles no longer yield adequate caving to warrant further cycles. At the completion of the cavity process, the well may be left open hole or a perforated liner may be installed (T.L. Logan 1989). Figure 3.6 is an illustration of a cavity completion.

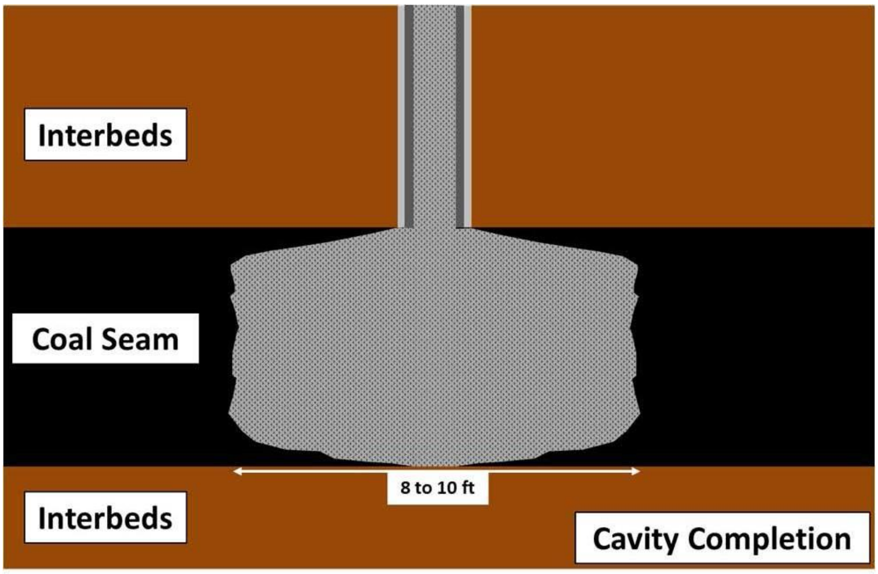


Figure 3.6 Vertical Open-hole Cavity Completion

Source: J. Caballero. 2013

The open-hole cavity completion technology is a process of repeatedly injecting air or an air-water mixture into an open-hole interval for one to six hours followed by a sudden release of the pressure during production. The increase and sudden decrease in well bore pressure during injection and rapid draw down can cause tensile failure extending in various orientations around the wellbore. It is also speculated that far field tensile fractures can be created which do not originate at the wellbore and may be oriented in any direction. As a by-product of the sudden decrease in pressure, the well bore enlarges due to sloughing in the friable, low strength coal due to superimposed hydrodynamic effects. (Logan, D. L., Mavor, M. J., & Khodaverdian, M. 1993)

Table 3.1 San Juan Basin Fruitland Coal Well Cost Comparison

Cased Hole*	**Drilling Cost (Less Stimulation) ($1,000)**	**Stimulation Costs ($1,000)**	**Total Well Cost ($1,000)**
Acidize	250 to 300	10 to 20	260 to 320
Crosslinked, gelled-water fracture	250 to 300	50 to 60	300 to 360
Slick-water fracture	250 to 300	25 to 30	275 to 330
Foam fracture (slick water)	250 to 300	75 to 85	325 to 385
Foam fracture (gelled-water)	250 to 300	100 to 110	350 to 410
Open hole Cavity	Drilling Cost Through Top Set Casing Point ($1,000)	Completion Costs ($1,000)	Total Well Cost ($1,000)
With predrilled liner	135 to 155	209 to 248	344 to 403
Without predrilled liner	135 to 155	175 to 198	310 to 353

Source: Palmer, I. D., Mavor, M. J., Seidle, J. P., Spitler, J. L., & Voiz, R. F. 1993

Total cost to drill and fracture stimulate a typical Fruitland coal well ranges from $260,000 to $410,000, depending on the type of stimulation planned (Table 3.1). For a slick-water fracture, the range is $275,000 to $330,000, only a little less than the cost of an open-hole cavity completion without a liner ($310,000 to $353,000). Where cavity completions work, they are worth the additional cost. The open-hole cavity completion has a greater risk of cost overrun because of wellbore instability and the possibility (along the fringes of the fairway) that commercial gas rates will not be established with this technique (hence, requiring fracture stimulation). (Palmer, I. D., Mavor, M. J., Seidle, J. P., Spitler, J. L., & Voiz, R. F. 1993)

（3）Vertical Well, Cased Perforated, Hydraulic Fracture Completion, Multi-seam

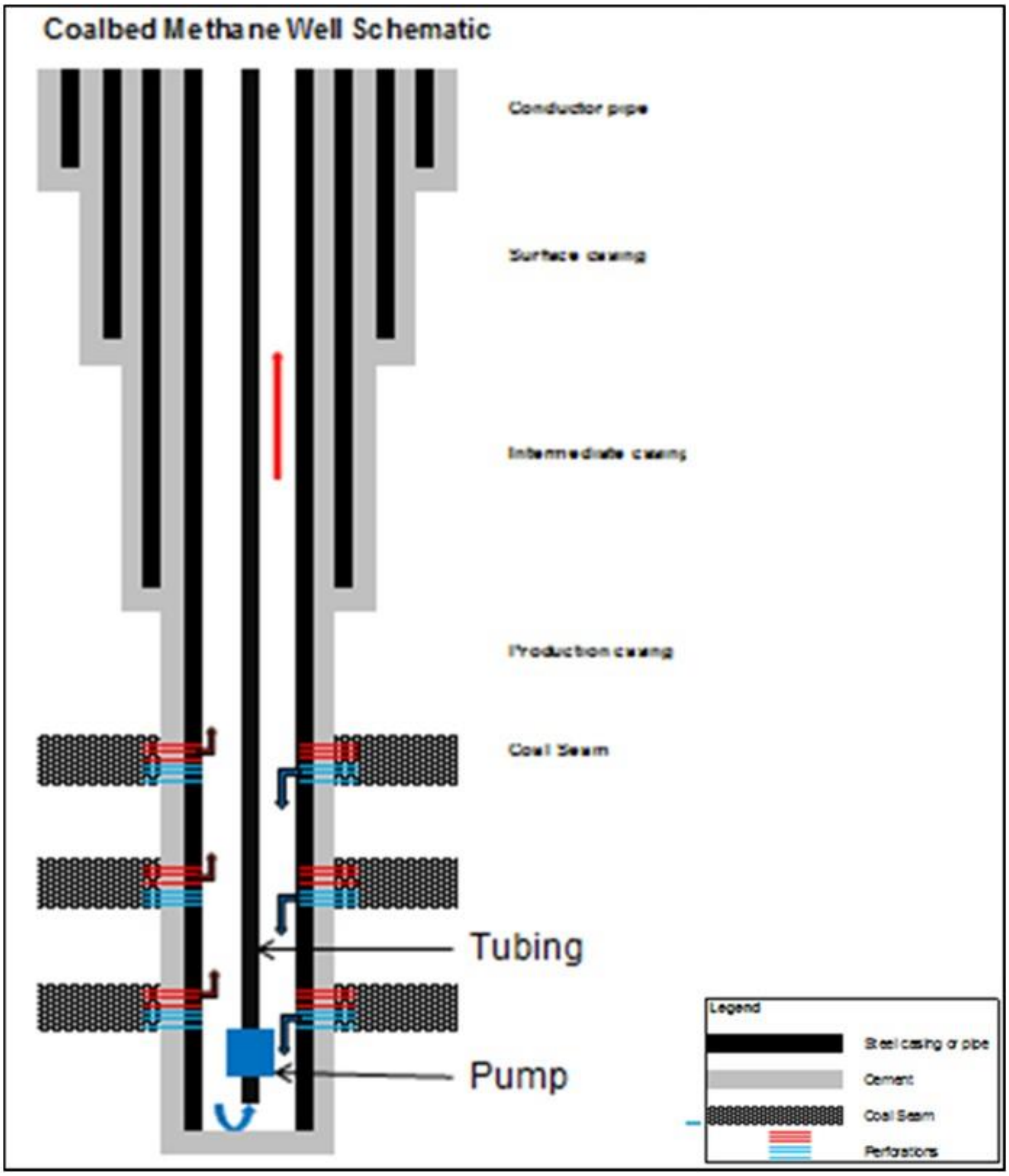
1. Plug and Perforate
2. Ball and Baffle
3. Multi Zone Stimulation Technology (MZST)

This technology is by far the most common technology for drilling and completing CBM fields, especially where multiple completable seams are encountered and many or most of them need to be hydraulically fractured in order to achieve economic flow rates and cumulative recoveries. This technology is typically used where the coal cleat system has permeability ranging from 0.1 to 100.0 md. Because hydraulic fracturing is utilized, a method of zone isolation must be used between hydraulic fracture stages. Three primary methods of zonal isolation will be discussed.

This technology is common in domestic US basins such as Central and Southern Appalachia, Black Warrior, Raton, and internationally in Australia, China, and India.

The technology involves drilling the production hole to a depth 50 to 100 ft below the lowest coal seam to be completed, and running and cementing production casing. Typical total depths may range down to 4000 ft. Zones are completed sequentially from bottom to top. The first zone to be completed is perforated (several individual coal seams may be included in each stage) and hydraulically fracture stimulated. The zone is then isolated and the next zone is perforated and hydraulically fractured. Zonal isolation can be accomplished by several technologies such as “perf and plug”, “ball and baffle”, Multi Zone Stimulation Technology (MZST), and others. Figure 3.7 is an illustration of this type of completion.

Figure 3.7 Schematic of a Vertical Cased Hole Multi-seam Hydraulic Fracture Completion



Source: J. Caballero. 2013

Perforating with explosive jet charges provides a more conventional approach to gaining access to the coals. Four to six perforations per foot will allow the client entry into the coal seam without heavy rubbiliza-tion of the coals, which has been seen at higher density perforating. The chances of placing perforations within a 30° angle of the induced hydraulic fracture direction are increased with the six Jet shots per foot (JSPF), 60° phased perforating, which reduces tortuosity and perforation friction during fracture stimulation treatments. Conventional perforat-ing is low cost and a routine operation by oil field workers. It allows selective opening of target zones and allows the stimulation engineer to design treatments for more complete coverage with the fracturing design. The completion design might need to include a small amount of hydrochloric acid for initial breakdown and cleanup of the perforations or as a spearhead to reduce entry pressures since the acid may remove cementing and perforating damage.(Rodvelt G 2014)

3.2.1.2 Advantages and disadvantages

(1) Vertical well, open-hole and under-ream completion, single seam

This type of technology is best suited for thick, vertically continuous, highly permeable coal seams. The primary advantage of this technology is that it is very inexpensive relative to other options discussed later. Disadvantages for this type of drilling and completion technology are that caving of the formation may cause fill which in turn may cause production problems, completion of deeper coal seams is nearly impossible, and completion of upper coal seams may be difficult and complicated. Also, because drilling stops at the base of the coal seam, there is no “sump” in which to place the pump, so part of the coal seam may remain under water.

(2) Vertical well, open-hole cavity completion, aingle aeam

Coal natural gas wells typically require stimulation resulting in effective wellbore to reservoir linkage to achieve economic gas production rates. The objective of a dynamic open-hole completion is to: a) effectively link the open-hole wellbore with the undamaged reservoir, b) create multi-directional self-propped fractures in the reservoir, and c) to intersect the natural fracture systems within the coal. A by-product of the dynamic open-hole completion procedure is an enlarged well bore caused by multiple pressure surges that encourage the friable and relatively low strength coal to slough into the wellbore. In this process, near wellbore damage is removed, multi-directional self propped fractures are created, and the enlarged wellbore may become linked to the natural fracture system within the reservoir.

During the open-hole completion process, it is hypothesized that failure occurs in the coal due to shear and tensile stresses creating numerous multi-directional tensile, shear and extension fractures. These fractures stimulate production by effectively linking the well bore to a large pre-existing natural fracture surface area within the coal gas reservoir.

Hydraulic fracturing can be an effective stimulation technique and is a commonly used to increase production rates from coal gas wells.(Palmer, I. D. 1992) However, in some areas, such as the northern San Juan Basin, hydraulic fracturing has not been as effective as dynamic open-hole completions. For example, Devon Energy Corporation replaced ten cased, hydraulic fracture stimulated wells with ten dynamically completed open-hole wells. The stabilized gas production from the open-hole wells exceeded the fractured wells by a factor of 6.1 to 1.5. Other operators have experienced similar improvements in the northern San Juan Basin where the coal is high volatile. A bituminous or greater rank, has an absolute permeability of 20mD (or greater), and is normally to over-hydrostatically pressured. We believe that the most important reservoir parameter influencing the success of an open-hole dynamic completion is absolute permeability. The coal reservoir must have adequate inherent natural fracture development and permeability for the completion technique to be successful in achieving commercial gas production rates.

A disadvantage of the open-hole cavity completion is the tendency for more coal-fines production into the wellbore than in cased-hole completions. This problem is magnified because the open-hole cavity completion does not have a rathole (or sump) below the lowest target coal seam to collect solid material, including coal fines. Another disadvantage is that individual coal seams cannot be selectively tested or stimulated as easily. Several cavity completions have been on production for more than 3 years without stability problems, but long-term hole stability still remains a question.(Palmer, I. D., Mavor, M. J., Seidle, J. P., Spitler, J. L., & Voiz, R. F. 1993)

(3) Vertical well, cased perforated, hydraulic fracture completion, multi-seam

Advantages of this technology are that all desired coal seams can be sequentially completed in stages leaving nothing behind pipe, coal particles and fines are generally well controlled behind pipe, minimizing formation caving and associated production problems such as pump and equipment plugging and hole fill-up.

Disadvantages may include somewhat higher cost and completion time depending on the number of hydraulic fracture stages, and wells may experience initial well clean up issues such as sand and coal fine production. Operators may control the initial rate of water level reduction in order to manage these problems.

Table 3.2 shows some advantages and disadvantages of the various completion techniques.(Osisanya, S. O., & Schaffitzel, R. F. 1996)

Table 3.2 Advantages and disadvantages of various completion techniques

Type of Completion	**Advantage**	**Disadvantage**
Open-hole completion	Reduce formation damage.	Frequent clean out due to wall sloughing Require fracturing due to low permeability, but this is difficult
Perforated Casing	Prevents sloughing hole and casing.	Difficulty in pumping fracture treatment through perforations. Requires high fracture treatment pressure unique to coalbeds (use strong casing; use fluid that will cause minimum damage) Expensive.
Stable Cavity	Useful in high permeability, high pressure and thick coalbed	Not understood May be costly

Source: Osisanya, S. O., & Schaffitzel, R. F. 1996

Vertical wells have been conventionally used for layers at shallow depths. Additional gas flow improvement is not compulsory as the assembly of the vertical and fracture wells are constant at these shallow depths because of high permeability and low pressure.

3.2.1.3 Successful case

(1) Open-hole cavity completion technology for vertical well

Surat basin

One of Arrow Energy's projects is located in the Surat basin in Queensland. The coals intersected in the Surat Basin are members of the Walloon Coal Measures (Walloon Subgroup) which are divided into the Juandah Coal Measure and the Taroom Coal Measure. The Walloon Coal Measure architecture is an inter-bedded coal, siltstone and sandstone sequence. The coals are generally thin with permeability ranging from 5-5000 mD. The Walloon subgroup coals are classified as high volatile bituminous. The Surat Basin has been developed using vertical and deviated wells penetrating the whole sequence. The Surat Basin coal reservoirs can be undersaturated or saturated. In the undersaturated case, single phase flow of water occurs during the early dewatering period. In the saturated case, two-phase flow of gas and water occurs at initial production.

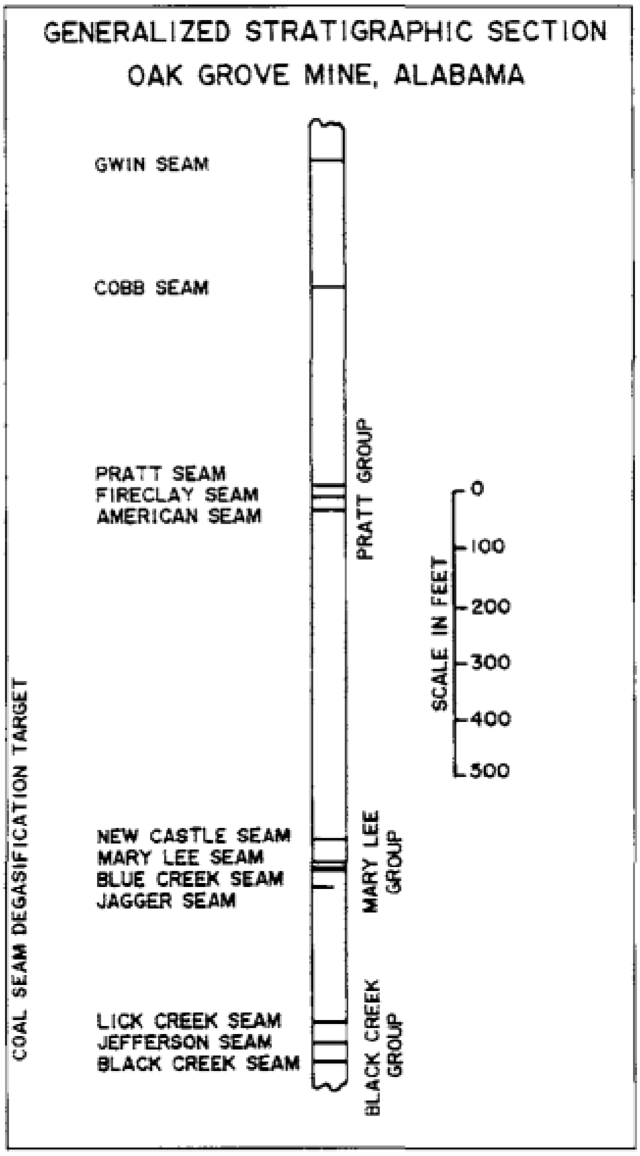
The Surat Basin in southern Queensland has become a primary focus area for CBM companies. First commercial production of CBM from the Jurassic Cretaceous Surat Basin coals began in early 2006 from the Kogan North field located west of the town of Dalby

Vertical wells allow access to multiple seams of the WCM and the high average permeability of coal results in a sustained, economic flow rate. Wells in the Surat Basin are normally completed in the Juandah or Taroom coal measures or commingled across both Juandah and Taroom coal measures. An open-hole completion technique with coal sections underreamed to a larger size is used. Casing is set immediately above the target coals and the well is then completed with a predrilled slotted liner. A Progressive Cavity Pump (PCP) is installed below the coal seam to produce water through tubing and gas is produced through the annulus. The water level is maintained below the coal layer in order to prevent water covering coal layers by adjusting the pump revolution per minutes (RPM). The water level is measured manually using airlines installed on the production tubing by injecting CO2 into the airline until the line pressure stabilizes and down hole water level can be established based on the airline depth and pressure differential.(I. Sugiarto,2013)

Black Warrior Basin

GRI, Taurus, and others have performed substantial research concerning the completion methods in the Black Warrior basin, Fig. 3.8 illustrates the coal stratigraphy in that area, The main producing horizon is the Mary Lee/Blue Creek coal seams. The completion method is to use air to drill the well through all coals, then cement casing with a lightweight cement. The formation may sustain some damage, but the long-term effects of the damage appear to be negligible.

Figure 3.8 Stratigraphic section showing the main coal groups of the Pennsylvania Age Pottsville formation,



Once the casing has been set, perforations are placed in the lower portion of the coal seam interval. Often, the perforations are in siltstones or shales near the coal seams rather than in the coal seams themselves. Perforations are placed outside the coal seam to minimize the failure of coals near the well bore and to minimize the chance of obtaining multiple vertical fractures at the wellbore.

From recent experience, if the well is perforated, then fracture-treated immediately, a single-planar, vertical fracture will be created that will grow several hundred feet vertically and connect many coal seams to the wellbore. Typically, downhole injection pressures during such treatments will range from 0.6 to 0.8 psi/ft.

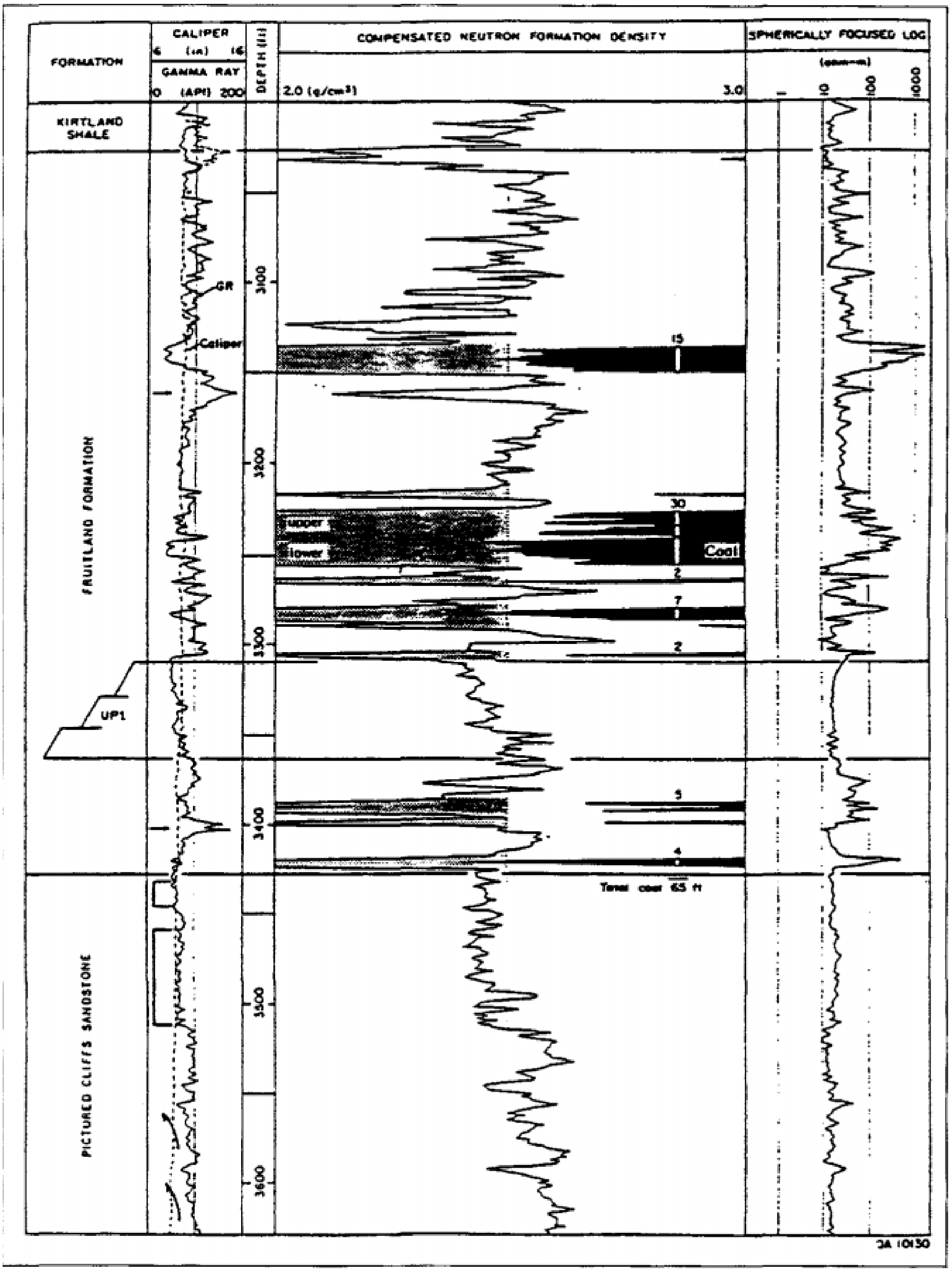
After the stimulation treatment, the well is produced back and eventually will be put on pump. The Mary Lee/Blue Creek coal seams can be dewatered in a reasonable time and gas desorption begins almost immediately. Over the first 1 to 2 years, gas production will increase gradually depending on the permeability of the coal seams that have been stimulated and the degree of regional depletion. Field data have shown clearly that when patterns or arrays of wells have been drilled to decrease reservoir pressure, gas desorption in the low-pressure area will increase and flow rates will improve with time.

San Juan Basin

Two primary completion methods are used in the San Juan basin, but the most prevalent is the perforated casing completion. For this area, the well is drilled to total depth with mud, then casing is set and cemented with a lightweight slurry.

Coal seams in the San Juan basin are different from those in many other basins because they are much more permeable and thicker than normally encountered. 28 Also, some coal seams in the San Juan basin are slightly geopressured. Fig. 3.9 illustrates the typical stratigraphic section for the Fruitland coals in the San Juan basin

Figure 3.9 Stratigraphic sequence for primary coals in the San Juan basin (after Ref. 28).



Because of the thickness of these coal seams, hydraulic fractures will be confined in the coal seams and multiple vertical, complex fractures will be created. When this occurs, the hydraulic fracture injection pressures are quite high, and obtaining a deep penetrating fracture is difficult. When the Fruitland coal is surrounded by shales, excessive fracture-height growth usually is not a problem. However, if the coal seam is immediately above or below a sandstone, fracture height can grow.

In some areas of the San Juan basin, the coal seams are highly fractured and contain permeabilities in excess of 25 md. In many of these areas, the stable cavity method appears to provide optimum gas flow rates. These wells are drilled with nondamaging fluids. Casing is set above the main coal target, then the coals are jetted from the well until a stable cavity is created. Normally, a slotted liner will be run in the well. Logan et al. have presented details of this completion method.

Regardless of the completion method, the coal seams in the San Juan basin must be dewatered. In some parts of the basin, free gas in the cleat system helps lift the water during the early stages of the well life. However, most wells eventually will be put on pump to lift water that is migrating through the coals.

Raton Basin

One operator has drilled about 20 wells in the Raton basin to test the Vermejo coals and determine the economic viability of those coal seams. During a pilot test program, some wells were drilled with air and some with mud and different perforating and stimulating practices were systematically investigated to determine optimum completion procedures.

Generally, drilling the wells with mud and cementing the casing did not damage the coal seams. Experimentation with pad volumes, pump rates, and proppant scheduling has led to an optimum stimulation design that includes two different-size proppants. A smaller (100 mesh) proppant is used during the early part of the treatment to help plug small fractures near the well bore and erode corners in the main fracture. The last portion of the treatment is pumped with larger-mesh proppants to pack the fracture and maximize fracture conductivity.

In the Raton basin, it appears that a singleplanar, vertical fracture is being created that cuts through multiple coal seams. In effect, the optimum completion methods in the Ra ton basin appear to be similar to the optimum completion methods in much of the Black Warrior basin. Additional production data are required to determine the economic viability of producing the Vermejo coal in the Raton basin.(Holditch, S. A. 1993, March 1)

3.2.2 Horizontal Well

3.2.2.1 Characteristics

(1) Short Radius (SRH)

Primary differences between short-radius drain hole drilling and conventional or extended reach directional drilling is the build angle, and is approximately 2 degrees per foot compared with build angles of 0.03 to 0.05 degrees per foot for conventional techniques. This means that the amount of drilling required before reaching horizontal is much less using the short-radius technique when compared to the conventional extended reach technique: 63 feet (19 m) as compared to 4400 feet (1341 m). In addition, the short-radius drain hole technique requires that the entire drill string is rotated from the surface rather than using downhole mud motors. (Logan, T. L., Schwoebel, J. J., & Horner, D. M. 1987)

(2) Long Radius (LRH)

LRH design is not suitable for CBM and many other unconventional horizontal drilling applications, because the kick-off point KOP above the desired lateral TVD is in excess of 950 feet, as is the distance from the surface location to the start of the lateral section in the desired reservoir zone (Figure 3.10). This excessive distance impacts the well’s ability to produce and limits the lateral footage able to be drilled because of additional geological zones exposed in the curve. In addition, the extra distance on the build portion of the well is much longer. This increases the section of high contact forces on the drilling assembly. 24 Ultra SRH wells have curve build rates greater than 60°/100’ (radius less than 95 feet) and are not used for CBM wells because of the limited lateral section achievable. Ultra SRH profiles are complex and are expensive to drill, requiring specialized equipment. (Lightfoot, J., 2007)

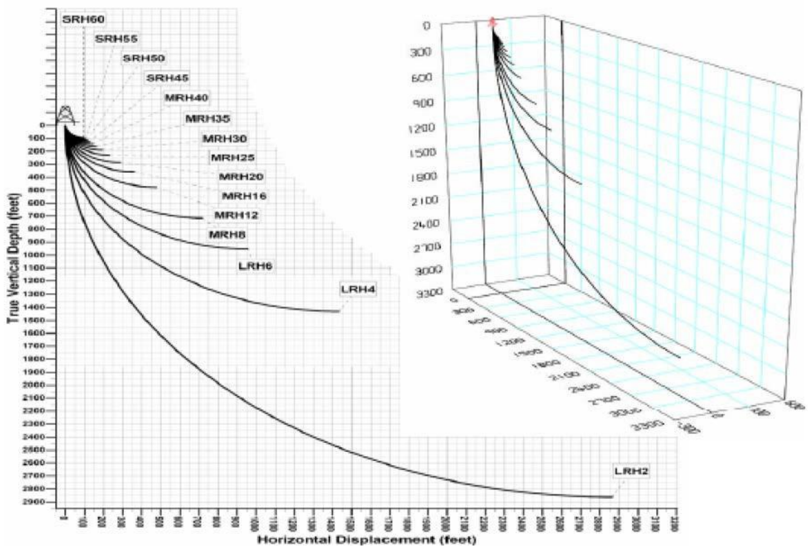


Figure 3.10 Horizontal well profiles

Source: Ramaswamy S. 2009

3.2.2.2 Advantages and disadvantages

Horizontal wellbores were considered to be very effective in reservoirs which were: a) relatively thin; b) naturally fractured; and c) known to have anisotropic permeability. Knowledge of just these properties can lead to the use of horizontal wellbores in coalbeds. Coalbeds were very seldom found that are greater than 100 ft in thickness and are closer to the 30 ft average. Natural factures are the basis of the coal matrix and offer an ideal opportunity for a horizontal borehole. Another consideration was the anisotropic permeability of the thin coalbeds.

Horizontal CBM wells have been used successfully in the Appalachian, Arkoma, and some parts of San Juan basin. Coal seam thickness varies from 3 to 20 ft in both the Appalachian and the Arkoma basin. Depth ranges from 500 to 4000 ft, and gas content exceeds 140 scf/t in both basins. From the industry response to the questionnaire, we conclude that coal should extend at least 1500 ft from a well, and coal seam dip should be less than 15 degrees. Thus, depth, thickness, areal extent, and dip of the coal seam are the main geologic factors that decide the selection of drilling horizontal wells. We conclude that a horizontal well completion is an option when the thickness of the coal ranges from 2 to 20 ft, the areal extent of the coal is more than 1500 ft, the depth ranges from 500 ft to 4000 ft, and the coal seam dip is less than 15 degrees.(Ramaswamy S. 2009)

Horizontal well production rates are 5 to 10 times greater than those of vertical wells. However, in cases where cases horizontal well are successful, vertical wells with cased holes and hydraulic fracture stimulation have been found to be successful also in San Juan basin, Arkoma basin and the Appalachian basins.

If the decision has been made to drill a horizontal well, then further decisions may be made concerning whether to drill a single lateral or multilateral well, based on the permeability of the coal. (Ramaswamy S. 2009)

Advantages of horizontal wells over vertical fracture stimulated wells that are they:

- can be drilled to a length of 8000 ft, whereas the effective CBM fracture lengths are usually less than 200 ft, tip-to-tip;
- can be oriented in the direction of maximum horizontal stress to intersect face cleats, to provide maximum wellbore stability;
- are better in reservoirs having high permeability anisotropy d) can be better controlled to stay in seam (to avoid wet zones) than can induced fractures;
- may provide accelerated cash flow and small foot-print; and
- can be expanded to various combinations (multilateral or pinnate designs, and multiple fracturing options). (Palmer 2007)

One of the advantages of in-seam horizontal drilling is the ability to orient boreholes perpendicular to the maximum permeability direction, or face cleat, thereby providing the most effective access to the coal reservoir. (Logan, T. L., Schwoebel, J. J., & Horner, D. M. 1987)

Some disadvantages of horizontal wells are that they are costly when there are many seams that require drilling multiple horizontals, and the chances of horizontals collapsing during drilling and production are high. A liner is highly recommended to prevent borehole collapse. In most cases, pre-perforated liner is used. (Palmer 2007)

3.2.2.3 Successful case

The 3 Deep Seam (3DS) horizontal drainhole drilling operations started on June 7, 1986. The initial drainhole (3DS-South) did not penetrate the target coal seam. The actual radius of the curve was 32 feet (9.7 m) which was 7 feet (2.1 m) less than the 39 feet (11.9 m) the curve drilling guide had been designed to drill. This put the end of the curve approximately 4 feet (1.2 m) above the top of the coal seam. The shorter-than-design radius curve may have been caused by the very competent, hard sandstone and shale drilled with the curved drilling guide (CDG) above the coal. An in-gauge hole was actually drilled with the CDG when the tool is designed to build the proper angle in a hole that is slightly oversized.

Several unsuccessful efforts were made to drop into the coal seam by modifying the horizontal drilling assembly. Drilling penetration rates were very slow (0.5 to 1 ft [15-30 em] per hour) during this operation due to excessive torque caused by the tight curve. Excessive drill pipe stress in the shorter-than-designed curve contributed to the eventual separation of the horizontal drilling assembly. The result left 112 feet (34 m) of flexible drill pipe in the horizontal hole. Other observed cracks in the drill pipe above the severed point indicated imminent tool failure. As shown in Figure 3.11, the 3DS-South drainhole had a horizontal displacement from the vertical wellbore of 114 feet (35 m); however, the drainhole did not intersect the target coal seam.

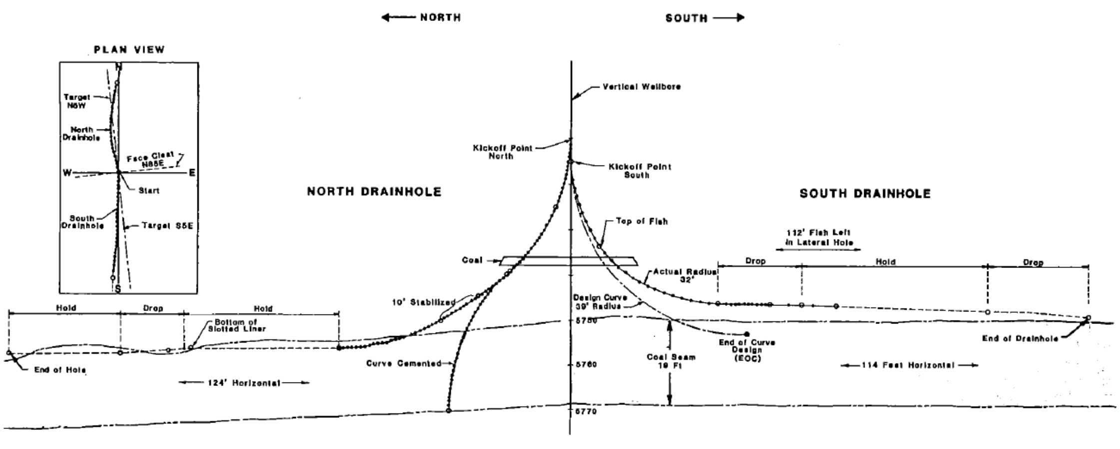


Figure 3.11 3 Deep Seam Drainhole Configuration

Source: Logan, T. L., Schwoebel, J. J., & Horner, D. M. 1987

Four options were available to correct the situation:

- Fishing the isolated horizontal assembly and flexible drill string out of the drainhole;
- Reset the whipstock below the first kick off point (KOP), and drill another drainhole in the same or opposite direction;
- Reset the whipstock above the first KOP and drill another drainhole in the same direction as before; and
- Reset the whipstock above the first KOP and drill another drainhole in the opposite direction as before.

In evaluating these options, it was believed, first, that fishing operations to retrieve the tools would be extremely difficult and costly due to minimal hole clearance. Second, in resetting the whipstock below the first KOP, drilling assemblies, particularly the bent curved drilling guide, and survey tools could hang up on the first drainhole when lowered past the drainhole. Third, in resetting the whipstock above the first KOP and drilling in the same direction, the chance existed included (a) the intersection of the first drainhole and fish, and (b) the inaccurate survey data due to interference by the metal in the nearby abandoned drainhole. Therefore, the whipstock was reset above the first KOP to drill a new drainhole in a direction 180 degrees opposite the first oriented downdip, and still perpendicular to the coal face cleat.

The curved drilling guide was redesigned to increase the radius to 43 feet (13.1 m) to assure intersection of the coal seam and account for raising the KOP 4 feet (1.2 m). Frequent surveys were planned to maintain the 43 feet (13.1 m) radius curve. The second survey indicated that penetration of the coal seam was imminent. When drilling resumed the coal seam was penetrated and 20 feet (6.1 m) of coal was drilled until the end of curve (EOC) was reached. However, a survey taken of the curve indicated that instead of drilling horizontally, the curve had actually turned downward caused by incorrect curved drilling guide installation. In order to proceed, the curve was partially cemented to allow initiation of another hole in the designed direction by kicking off the hard cement plug. After the cement had set, drilling operations resumed by drilling slowly at 0.5 ft/hr (15 cm/hr). Increasing amounts of shale and sandstone cuttings were observed which indicated the cement plug was kicked-off successfully.

After drilling approximately 2/3 of the curve, a rigid drilling mandrel (RDM) was used to extend the current angle. Utilization of the RDM before reaching the end of curve was conceived and first used in this drainhole to assure coal seam penetration. After 10 feet (3. 04 m) of the hole was drilled with this technique, the curved drilling guide was again used to finish the curve. Upon entering the coal, gas shows increased to levels almost twice those encountered in the other vertical wells at Red Mountain Site.

A total horizontal displacement of 124 feet (37 .8 m) was achieved in which a total of 73 feet (22.2 m) of coal was penetrated. The drainhole was targeted and placed in the top of the coal seam because previous horizontal drilling experience had shown that it is more difficult to build than to drop angle in a coal seam. While drilling horizontally in the down-dipping coal seam the top of the coal was penetrated due to an anomalous role or dip in the coal. Two different dropping assemblies were used to attempt to drop back into the coal seam. The first assembly was unsuccessful and consisted of a PDC bit and flexible articulated drill pipe without stabilizers. The second dropping assembly was based upon experience from inseam horizontal drilling at the Soldier Canyon Mine Project. The tool used was a modified flexible articulated drill pipe with carbide chips placed around the tool body to ream the bottom of the hole. This dropping assembly was successfully used to drop back into the coal seam and drill 25 additional feet (7 .6 m) of coal before hitting the top of the seam again. During the final reaming operation in the horizontal well, the tool parted near the end of the drainhole. The wellbore location of each horizontal drainhole is shown in Figure 3.8.(Logan, T. L., Schwoebel, J. J., & Horner, D. M. 1987)

3.2.3 Multi-lateral Horizontal Well

3.2.3.1 Characteristics

(1) Vertical well, open-hole under-ream with intercepting surface to in-seam open-hole

multi-lateral horizontal Wells

Originally developed as a coal mine methane (CMM) method for removing gas from coal seams prior to underground mining for safety reasons, this technology has been used in low permeability high rank coal seams. The technology has been successful in producing significant quantities of gas from low permeability coal seams, but high drilling cost has challenged viable economics.

Multi-lateral horizontal wells are drilled in cases where the ratio of horizontal well gas production rate and vertical well gas production rate is less than one.(Palmer 2007) In these cases, the total contact area for a vertical well is more than that for a single horizontal well. In cases where a number of thin coal seams are to be accessed, multiple lateral wells will provide greater production than a vertical well.

It can be subdivided into (Figure 3.12):

- Single lateral(one horizontal borehole)
- Multi-lateral (two or more laterals in a seam
- Multi-lateral stacked(two or more laterals in separate seams)

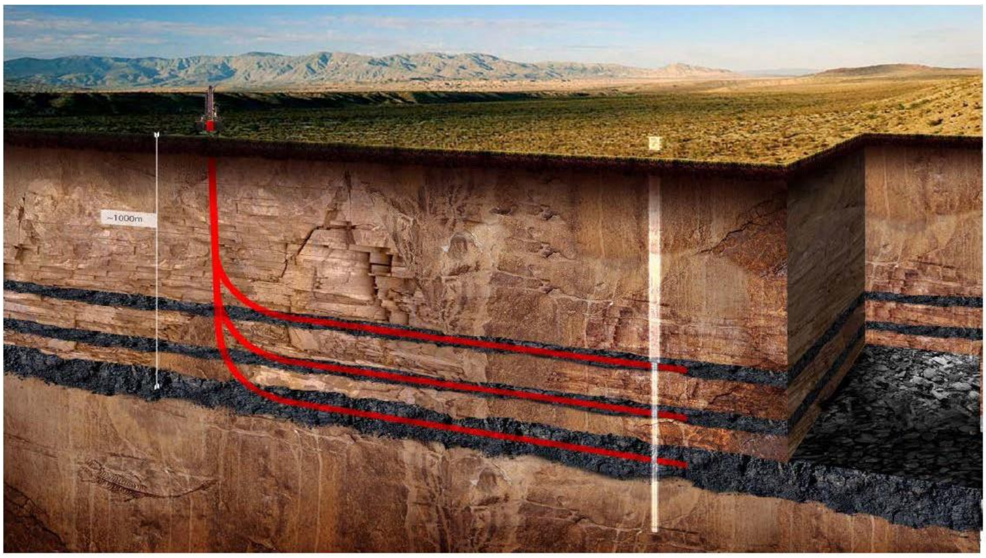


Figure 3.12 Multi-lateral pattern drilling

This technology is similar to the previous technology, in that a vertical well is drilled to the top of the coal seam and production casing is run and cemented. The coal seam is then drilled and under-reamed. At this point, a nearby surface to in-seam well is drilled to a depth near the top of the coal seam where a tight radius turn is made and a horizontal in-seam well intersects the under-reamed portion of the vertical well. This is illustrated in Figure 3.13. The in-seam well is drilled through the coal, typically for approximately 0.7 mile. The drill string is then retracted, and side lateral wells are drilled into the coal seam in a "pinnate" pattern as shown in Figure 3.14.

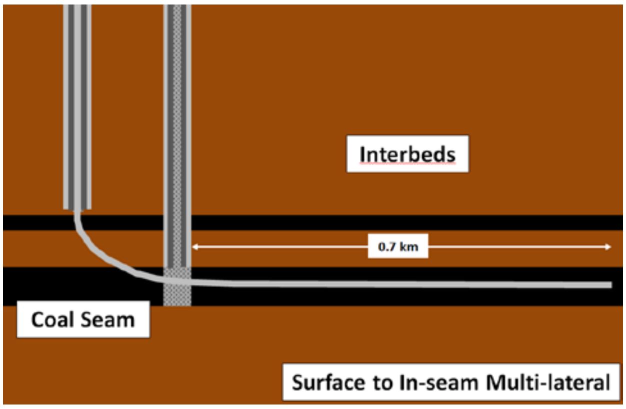


Figure 3.13 Surface to In-seam Multi-Lateral Well

Source: J. Caballero 2013

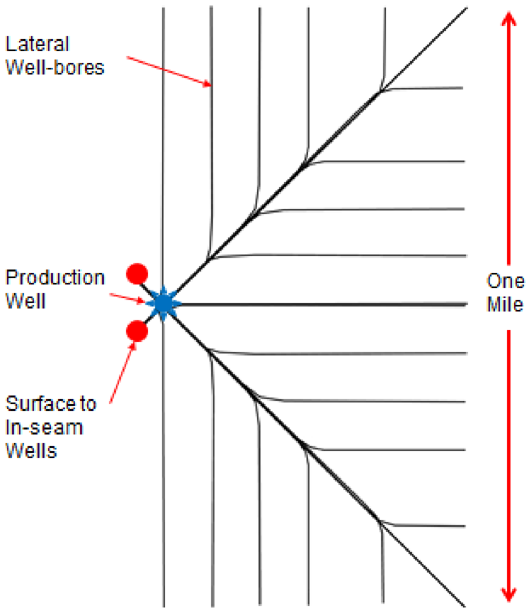


Figure 3.14 Schematic Plan View of Two Multi-lateral "Pinnate" Patterns

Source: J. Caballero 2013

(2) Pinnate Wells Pattern

Recent advances in drilling technologies have allowed some operators to re-evaluate the economic viability of developing unconventional low permeability reservoirs that had been previously discounted due to poor production performance. CDX Gas, LLC of Dallas, Texas has developed a patented drilling system that has dramatically enhanced production recoveries from tight coals and shales. The Z-Pinnate Drilling and Completion Technology™ (Pinnate Technology) employs horizontal drilling techniques in a multi-well pattern that create an efficient and environmentally friendly recovery method. CDX developed its Pinnate Technology during the mid-1990's as an extension of the underground horizontal drilling operations for coal seam degasification in advance of mining at the US Steel Company Pinnacle coal mine in Pineville, WV.(Schoenfeldt H V, Zupanik J. 2004)

Pinnate pattern, multilateral wells have proved very successful in producing coalbed gas from low-permeability coals (Figure 3.6). Pinnate wells may have a 20-fold increase in production rate, compared to fracture-stimulated vertical wells.(CDX Gas, http://www.cdxgas.com/Technology.htm, 18 May 2007)

The pinnate well pattern was developed by CDX drilling Inc. to produce CBM from low-permeability coals (Figure 3.15). This method is extensively used in the Arkoma basin. Some advantages of pinnate wells are that:

- wells can drain up to 2000 acres from a single drill pad;
- gas is produced immediately;
- peak gas production is reached quickly, unlike a vertical well in CBM reservoir;
- wells can drain a reservoir in 2 to 4 years;
- gas recovery is high (80 to 90%); and
- high gas flow rates (1 to 5 MMcfd) can be achieved.

These wells are not suitable in high permeability coals, as many cases of lateral collapses have occurred.(Schoenfeldt, H. et al., 2004)

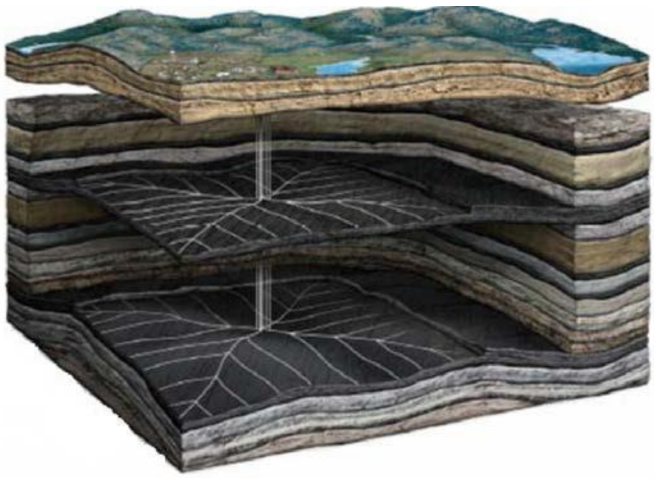


Figure 3.15 Pinnate pattern drilling

Source: CDX Gas, http://www.cdxgas.com/Technology.htm, 18 May 2007.

(3) Vertical well, open-hole under-ream with intercepting surface to in-seam open-hole multi-lateral horizontal wells

(4) Pinnate wells pattern

The Z-Pinnate Drilling and Completion Technology™ (pinnate technology) employs horizontal drilling technologies in a multi-well pattern that creates an efficient and environmentally friendly recovery method. CDX pinnate technology makes CBM production from challenging reservoirs viable. (CDX Gas)

In pinnate technology, first, a “cavity” well is drilled. That is, a conventional vertical well that is enlarged at the coal seam level to a diameter of 8 feet (Prime Western 2007). The second well is directionally drilled to intersect the cavity at a predetermined point and extended to a length of up to 1 mile in the seam. From this main lateral, numerous horizontal laterals are drilled to roughly cover a square area (Figure 3.16: single pinnate). The pinnate system is the multilateral horizontal drainage network confided in the shape of a leaf. A single pinnate can cover an area of up to 320 acres. A single pinnate pattern can be drilled in 4 directions offset by 90° each to cover an area of up to 1,200 acres over 360°. (Figure 3.17: quad pinnate). In the ongoing effort to reduce drilling cost, more advanced horizontal drilling patterns have also been developed. (Schoenfeldt, H. et al., 2004)

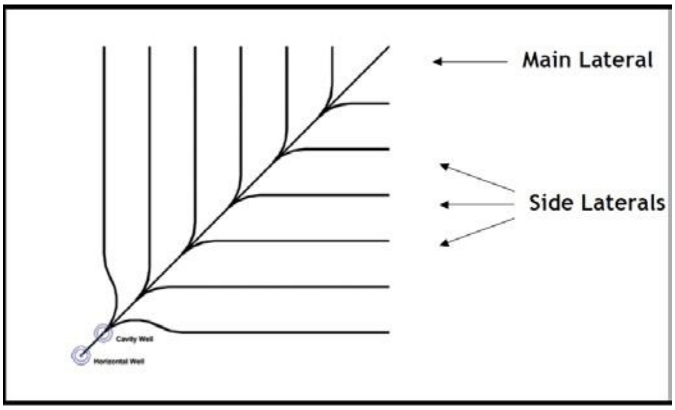


Figure 3.16 Single pinnate

Source: Schoenfeldt, H. et al., 2004

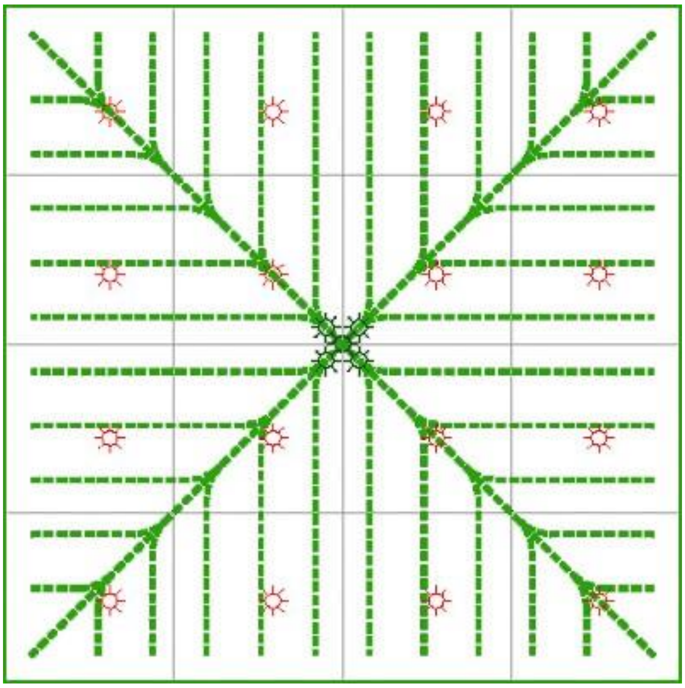


Figure 3.17 Quad pinnate

Source: Schoenfeldt, H. et al., 2004

In the CDX pinnate drilling system, the gas production is accelerated and increased ultimate resource recovery compared with conventionally completed wells. (Schoenfeldt, H. et al., 2004) Figure 3.18 shows production decline curves for a horizontal pinnate well and conventionally completed vertical wells in the Central Appalachian Basin. The decline curve for the vertical (conventional) well represents the total production from 15 wells drilled on 80-acre spacing needed to cover the 1,200- acre area.

An unusual characteristic of the CDX decline curve is its almost immediate gas production. This eliminates the typical lengthy dewatering period of conventional CBM wells prior to significant gas production. Furthermore, the production decline is steep; usually 75 per cent to 85 per cent of the recoverable gas is produced in only two to three years. CDX reports that with their drilling and completion system it is possible to accurately control direction and length of the horizontal laterals in the coal seam. (Schoenfeldt, H. et al., 2004)

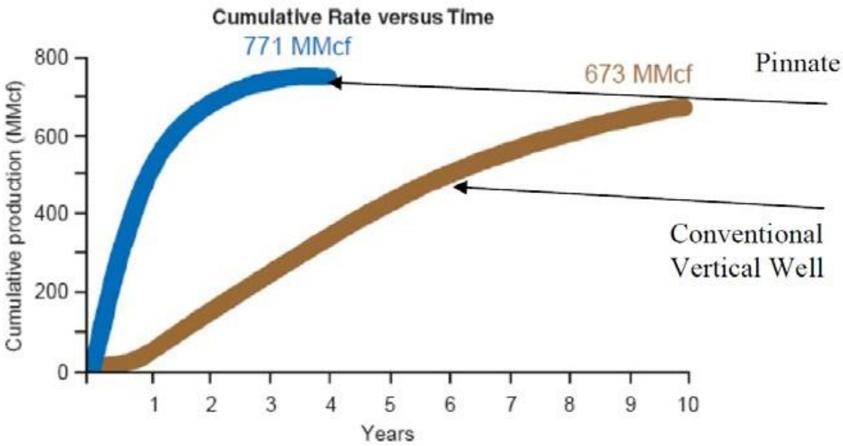


Figure 3.18 Comparison of production from a vertical well and a pinnate well in the North Appalachian Basin

Source: Ramaswamy 2009

3.2.3.2 Advantages and disadvantages

(1) Vertical well, open-hole under-ream with intercepting surface to in-seam open-hole multi-lateral horizontal wells

When drilling is completed, in one pinnate pattern covering 0.25 mi2, as much as 20,000 ft of hole may be drilled (Keim S A. 2011). Production is by pump in the vertical well as discussed previously. This type of drilling and completion technology has the same advantages and disadvantages as the previous surface to in-seam technology discussed, with the additional disadvantages; 1) it is not possible to install plastic liners in the multiple lateral wells sections; 2) in relatively thin coal seams and where geologic complexity exists, core hole drilling may be required to properly locate the in-seam well sections.

(2)Pinnate wells pattern

The Technology offers significant benefits over conventional drilling and completion technologies both for the environment and for project economics, as follows:

A. Environmental Benefits

a) The CDX drilling equipment has been reduced in size and leaves a "smaller foot print" on the surface that takes up considerably less space than conventional drilling and completion equipment (Figure 3.19). The reason for the reduced space needs lies in the fact that with the Pinnate Technology hydraulic fracture stimulation is not required eliminating the need for the large fracturing equipment and tankage.

Figure 3.19 CDX Drilling Rig on Location in Central Appalachian Basin

Source: Schoenfeldt, H. et al., 2004.

b) CDX Pinnate wells drilled from one location on a 1,200-acre drilling unit replace up to 16 conventional well sites that are drilled on 75-acre spacing (Figure 3.20). Not only does the Pinnate Technology require considerably fewer well locations for a given area, but each well site also needs less space than a conventional drill pad. As a result of fewer drill pads, fewer roads and pipelines need to be laid to drain the same area as conventionally developed CBM fields thus lessening the environmental impact of the drilling and production operation. The cumulative footprint of a pinnate development is roughly 10% as large as that required for conventional vertical CBM wells.

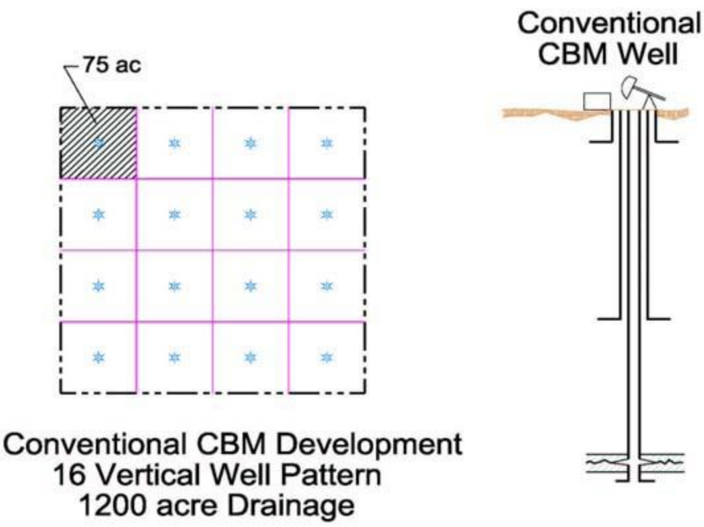


Figure 3.20 CDX Z-Pinnate Site Replaces 16 conventional Well Sites on 1,200 Acre Unit

Source: Schoenfeldt, H. et al., 2004.

c) CDX maximizes gas recovery from the coal as a result of the far reaching drainage pattern, and consequently minimizes emission of methane into the atmosphere. Methane is known to be a potent GHG, with 23 times the radiative forcing potential of carbon dioxide.

d) CDX has also developed a technology to dispose produced formation water underground without the need to lift it to the surface, assuming the water is unfit for surface disposal.

e) The Pinnate Technology is ideal for delicate terrain around environmentally sensitive areas such as forests, reservoirs, inaccessible canyons and mountains due to its ability to its ability to reach out in any direction for a mile or more.

f) Pinnate wells potentially could produce water for local irrigation needs of populations in remote areas with little infrastructure if the water is of sufficient quality. The technology typically produces copious amounts of water from the network of far reaching horizontal holes.

g) The depleted network of drainage holes is an ideal receptacle for CO_2 sequestration applications, when drilled in coal seams that are not suitable for mining.

B. Economic Benefits

Benefits of accelerated gas production rates, higher resource recovery and reduced construction cost include expedited return on investment and higher project net present value (NPV) as illustrated in the following table 3.3.

Table 3.3 Comparative Economics for a 1,200-acre CBM Project

	Vertical	**Horizontal**
Revenue-PV (10)	\$3,676,000	\$6,689,000
CAPEX	(\$2,420,000)	(\$1,635,000)
Lease Operating (\$0.55/mcf)	(\$751,000)	(\$934,000)
Interest	(\$746,000)	(\$66,000)
Severance Tax (3%)	(\$185,000)	(\$201,000)
G&A	(\$500,000)	(\$500,000)
Profit & (Loss)	(\$926,000)	(\$3,535,000)

Source: Schoenfeldt, H. et al., 2004.

These data were generated based on the following assumptions: Coal thickness – 6 ft. (single seam); overburden thickness - 1,000 ft.; gas content - 200 ft^3/ton; permeability - 5 mD; gas production was based on the decline curves indicated in Figure 3.18.

Technical advantages of the present invention include providing an improved method and system for accessing subterranean deposits from the surface. In particular, a horizontal drainage pattern is drilled in a target Zone from an articulated surface well to provide access to the Zone from the surface. The drainage pattern intersected by a vertical cavity well from which entrained water, hydrocarbons, and other fluids drained from the Zone can be efficiently removed and/or produced by a rod pumping unit. As a result, gas, oil, and other fluids can be efficiently produced at the surface from a low pressure or low porosity formation.

The second technical advantage of the present invention includes providing an improved method and system for drilling into low-pressure reservoirs. In particular, a down hole pump or gas lift is used to lighten hydrostatic pressure exerted by drilling fluids used to remove cuttings during drilling operations. As a result, reservoirs may be drilled at ultra-low pressures without loss of drilling fluids into the formation and plugging of the formation.

The third technical advantage of the present invention includes providing an improved horizontal drainage pattern for accessing a subterranean Zone. In particular, a pinnate structure with a main diagonal and opposed laterals is used to maximize access to a subterranean Zone from a single vertical Well bore. Length of the laterals is maximized proximate to the vertical Well bore and decreased toward the end of the main diagonal to provide uniform access to a quadrilateral or other grid area. This allows the drainage pattern to be aligned with long Wall panels and other sub surface structures for degasification of a mine coal seam or other deposit.

The fourth technical advantage of the present invention includes providing an improved method and system for preparing a coal seam or other subterranean deposit for mining. In particular, surface Wells are used to degasify a coal seam ahead of mining operations. This reduces underground equipment and activities and increases the time provided to degasify the seam which minimizes shutdowns due to high gas content. In addition, Water and additives may be pumped into the degasified coal seam prior to mining operations to minimize dust and other hazardous conditions, to improve efficiency of the mining process, and to improve the quality of the coal product.(Zupanick J A, Rial M H. 2013)

The fifth technical advantage of the present invention includes providing an improved method and system for producing methane gas from a mined coal seam. In particular, well bores used to initially degasify a coal seam prior to mining operations may be reused to collect gob gas from the seam after mining operation. As a result, costs associated with the collection of gob gas are minimized to facilitate or make feasible the collection of gob gas from previously mined seams.

The sixth technical advantage of the present invention includes providing a positioning device for automatically positioning down-hole pumps and other equipment in a cavity. In particular, a rotatable cavity positioning device is configured to retract for transport in a well bore and to extend within a down-hole cavity to optimally position the equipment within the cavity. This allows down-hole equipment to be easily positioned and secured within the cavity.

The last advantages of the present invention will be readily apparent to one skilled in the art from the following figures, description, and claims.(Zupanick J A. 2002)

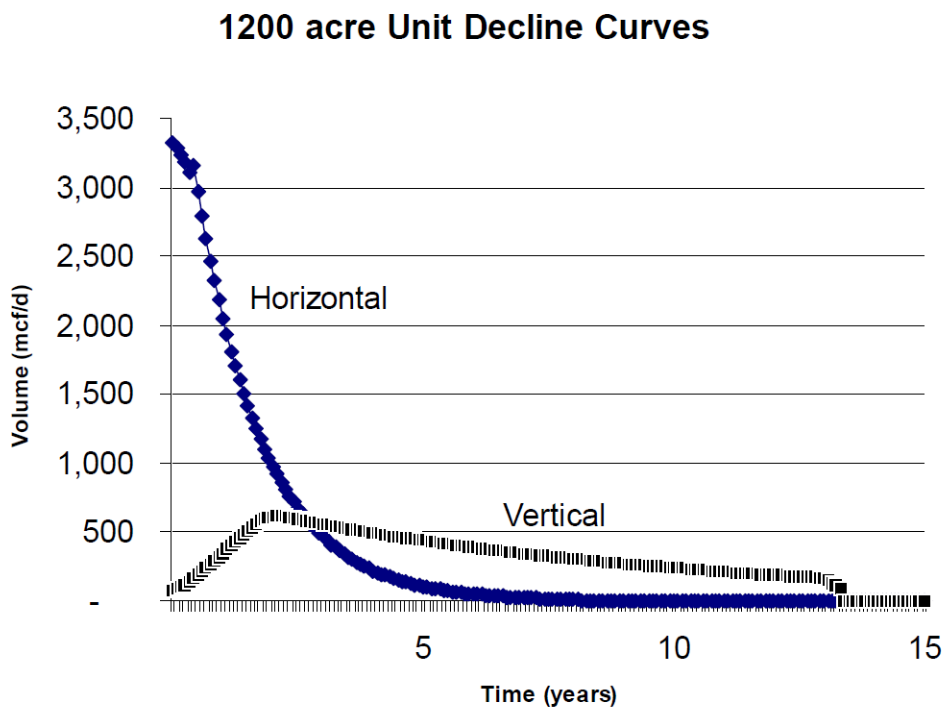


Figure 3.21 Production Decline Curve Comparison Horizontal Versus Vertical Wells For 1,200 Acre Unit

Source: Schoenfeldt H V, Zupanik J. 2004

It also requires fewer roads, pipelines, compressor stations and drill pads thereby reducing up-front expenditures.(Schoenfeldt H V, Zupanik J. 2004)

3.2.3.3 Successful case

CDX Gas report costs of $2.2 million for wells targeting coals 275–395 m (900–1000 ft) deep in their Hillman Field in West Virginia. Laterals are drilled in a pinnate pattern for a total drilled length over 6100 m (20,000 ft) and drain 2.4 km2 (600 acres). Wells have initial production of over 14 Mcmd (500 Mcfd).(Kravits S, Dubois G 2014) In 2008, 21 wells were producing in the Hillman Field at a rate of 595 Mcmd (21 MMcfd). The average estimated ultimate recovery (EUR) per well is about 28 MMcm (1 Bcf) per well. CDX Gas has used their pinnate drilling pattern to drain coal seams at the Pinnacle Mine in West Virginia reporting that 60–65% of all in situ gas was recovered in a 2–3 year period. In 2006, the Pinnacle Mine recovered and sold approximately 130 Mcmd (4.6 MMcfd) of gas from its premine drainage wells. CDX has drilled over 250 pinnate patterns totaling over 5 million feet as of the spring of 2008 in the Appalachian and Arkoma coal basins (Lusk and Jones, 2008).

3.3 Fracturing Technology of Coalbed Methane Well

3.3.1 Direct Fracturing Technology

3.3.1.1 Hydraulic fracturing technology

(1) Technical Principle

If fluid is pumped into a well faster than the fluid can escape into the formation, inevitably pressure rises, and at some point, something breaks. Because rock is generally weaker than steel, what breaks is usually the formation, resulting in the wellbore splitting along its axis as a result of tensile hoop stresses generated by the internal pressure. The simple idea of the wellbore splitting like a pipe (shown in Figure. 3.16) becomes more complex for cased and/or perforated wells and non-vertical wells. However, in general, the wellbore breaks—i.e., the rock fractures—owing to the action of the hydraulic fluid pressure, and a “hydraulic” fracture is created. Because most wells are vertical and the smallest stress is the minimum horizontal stress, the initial splitting (or breakdown) results in a vertical, planar parting in the earth.

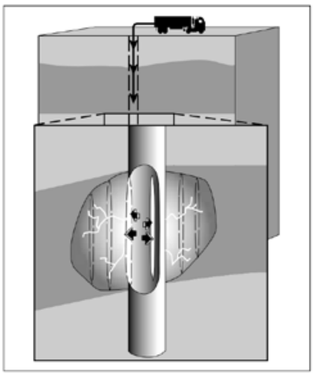


Figure 3.16 Internal pressure breaking a vertical wellbore

Source: Michael J. Economides，2000

The breakdown and early fracture growth expose new formation area to the injected fluid, and thus the rate of fluid leaking off into the formation starts to increase. However, if the pumping rate is maintained at a rate higher than the fluid-loss rate, then the newly created fracture must continue to propagate and grow (Figure. 3.17). This growth continues to open more formation area. However, although the hydraulic fracture tremendously increases the formation flow area while pumping, once pumping stops and the injected fluids leak off, the fracture will close and the new formation area will not be available for production. To prevent this, measures must be taken to maintain the conductive channel. This normally involves adding a propping agent to the hydraulic fluid to be transported into the fracture. When pumping stops and fluid flows back from the well, the propping agent remains in place to keep the fracture open and maintain a conductive flow path for the increased formation flow area during production. The propping agent is generally sand or a high strength, granular substitute for sand. Alternatively, for carbonate rocks, the hydraulic fluid may consist of acid that dissolves some of the formation, leaving behind acid-etched channels extending into the reservoir.

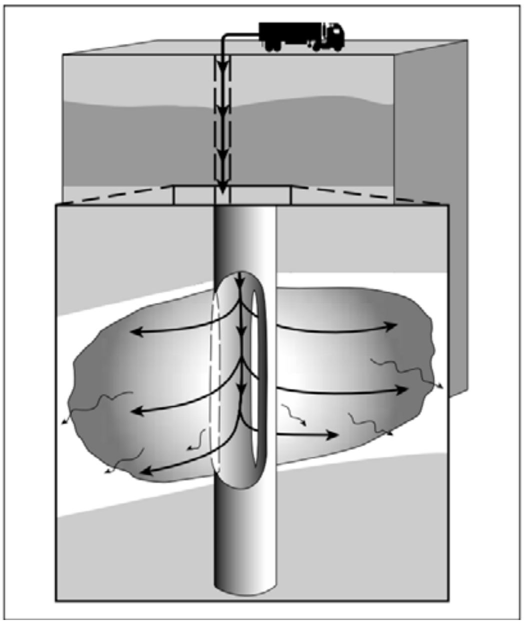


Figure 3.17 Cross-sectional view of a propagating fracture

Source: Michael J. Economides，2000

After the breakdown, the fracture propagation rate and fluid flow rate inside the fracture become important. They are dominated by fluid-loss behavior. As introduced by Carter (1957), the fluid-loss rate.

Initially, fracture penetration is limited, and hence fluid loss is high near the wellbore. This is termed the pad. The purpose of a pad is to break down the wellbore and initiate the fracture. Also, the pad provides fluid to produce sufficient penetration and width to allow proppant-laden fluid stages to later enter the fracture and thus avoid high fluid loss near the fracture tip. After the pad, proppant-laden stages are pumped to transport propping agent into the fracture.

However, because fluid loss to the formation is still occurring, even near the well, the first proppant is added to the fluid at low concentrations. The proppant-laden slurry enters the fracture at the well and flows toward the fracture tip (Figure. 3.18). At this point, two phenomena begin. First, because of the higher fluid loss at the fracture tip, slurry flows through the fracture faster than the tip propagates, and the proppant-laden slurry eventually overtakes the fracture tip. Next, because of fluid loss, the proppant-laden slurry stages lose fluid (but not proppant) to the formation.

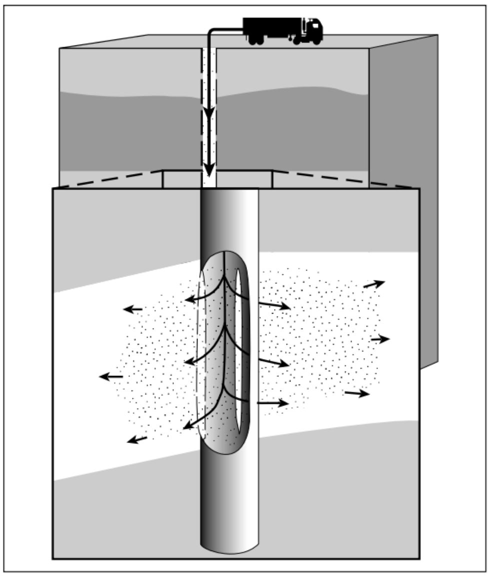


Figure 3.18 Introducing proppant into the fracture

Source: Michael J. Economides，2000

Thus, proppant concentration (i.e., volume fraction of solid proppant) increases as the slurry stages dehydrate. The pump schedule, or proppant addition schedule, must be engineered much like handicapping horse races, but with no single winner. Rather, all

stages should finish at the right place, at the right time, with the right final proppant concentration. The pad should be completely lost to the formation, and the first proppant stage should be right at the fracture tip (which should be at the design length).

As the proppant slurry stages move down the fracture, they dehydrate and concentrate. Slurry stages pumped later in the treatment are pumped at a higher concentration. These stages are not in the fracture for long prior to the treatment end (i.e., prior to shutdown) and are thus exposed to less fluid loss and less dehydration. Ideally, the first proppant stage pumped reaches the fracture tip just as the last of the pad fluid is lost into the formation (a correctly handicapped race), and this first stage has concentrated from its low concentration to some preselected, higher final design concentration. Meanwhile, the slurry concentration being pumped is steadily increased to the same final design concentration. At treatment end, the entire fracture is filled with the design concentration slurry.

The preceding description might be termed a “normal” design, where the entire fracture is filled with a uniform, preselected, design proppant concentration just as the treatment ends. If pumping continues past that point, there would be little additional fracture extension because the pad is 100% depleted. Continued pumping forces the fracture to become wider (and forces the pressure to increase) because the increased volume simply acts like blowing up a balloon. In some cases, the additional propped width that results may be desirable, and this procedure is used purposely. This is termed tip-screen out (TSO) fracturing.

At the conclusion of the treatment, the final flush stage is pumped. This segment of a treatment consists of one wellbore volume of fluid only and is intended to sweep the wellbore clean of proppant (Figure. 3.19). The well is generally then shut-in for some period to allow fluid to leak off such that the fracture closes on and stresses the proppant pack. Shut-in also allows temperature (and chemical breakers added to the fluid while pumping) to reduce the viscosity of the fracturing fluid. Ideally, this process leaves a proppant-filled fracture with a productive fracture length (or half-length xf), propped fracture height and propped fracture width (which determines the fracture conductivity kfw). Here, xf is the productive fracture half-length, which may be less than the created half-length L or less than the propped length.

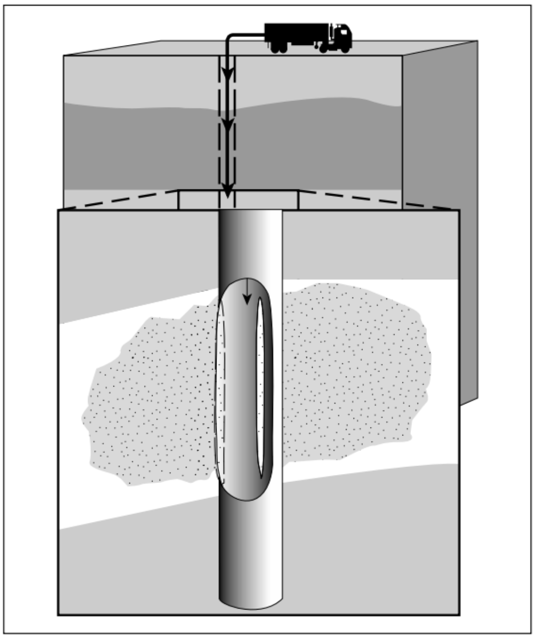


Figure 3.19 Flushing the wellbore to leave a propped fracture

Source: Michael J. Economides，2000

(2) Technical advantages and disadvantages

A. Advantages:

Hydraulic fracture operations may be performed on a well for one (or more) of three main reasons:

a) to bypass near-wellbore damage and return a well to its “natural” productivity.

Near-wellbore damage reduces well productivity. This damage can occur from several sources, including drilling-induced damage resulting from fines invasion into the formation while drilling and chemical incompatibility between drilling fluids and the formation. The damage can also be due to natural reservoir processes such as saturation changes resulting from low reservoir pressure near a well, formation fines movement or scale deposition. Whatever the cause, the result is undesirable. Matrix treatments are usually used to remove the damage chemically, restoring a well to its natural productivity. In some instances, chemical procedures may not be effective or appropriate, and hydraulic fracture operations are used to bypass the damage. This is achieved by producing a high conductivity path through the damage region to restore wellbore contact with undamaged rock

b) to extend a conductive path deep into a formation and thus increase productivity beyond the natural level.

Unlike matrix stimulation procedures, hydraulic fracturing operations can extend a conductive channel deep into the reservoir and actually stimulate productivity beyond the natural level.

c) to alter fluid flow in the formation.

B. Disadvantages:

a) Harmful to the Environment and the People.

Despite the apparent reduced carbon emissions brought about by fracking, setbacks are still present like water and noise pollution. Fracking itself might not be emitting carbon in the air but the 400 tankers that are on the roads, going to and from the site still burn fossil fuel and emit carbon. The people living in the perimeter of the site will be subjected to noise caused by the drilling and also the gas emissions coming from tankers. These tankers are also flammable and in case of accidents, explosions and deaths are possible.

b) Waste of Water.

Even if the supposedly benefit of fracking is reduced water consumption due to the replacement of fossil fuel with natural gas, this is not the case while the drilling is still on-going. Millions of gallons of water are needed in just a single fracking activity and this will definitely affect water supply. Moreover, some parts of the member economy goverment are experiencing drought and which is not a good thing.

c) Problems of Water Contamination.

Aside from the imminent hazards to the environment, demonstrators of anti-fracking are angry at the possibility that these fracking activities can contaminate drinking water and can cause health hazards as well to the people of the community. Accidents can happen, including the accidental seeping of the chemicals to water pipes and drain buried underground if the drilling equipment hits and breaks these pipes. There have already been reports that residents of certain communities are becoming sick due to the presence of drilling activities. Moreover, there have been reports from homeowners that there are traces of chemicals found in their water pipes.

(3) Case Study

A. Successful Cases in Australia

The Broadmeadow Pilot Project was initiated in August 1987 on the western edge of ATP 364P with the drilling of 3 single-seam completion wells. These were followed in February 1988 by an additional 5 single-seam wells. A core well was also drilled in January 1988. Testing for the project has included gas content, vitrinite reflectance, proximate analyses, and adsorption/desorption isotherms, slug tests, injection/fall-off tests, and fluid sample analyses. Results have indicated that the Broadmeadow area can be characterized as having an excellent reservoir storage capacity for methane, low percentages of contaminants in the gas, and a modest permeability. All eight wells are pumping, powered by electricity from a methane-fired generator. Production is being monitored from 6 of the wells, which the remaining two to be brought on-stream in the near future.

In August 1987 the Broadmeadow Pilot Project was initiated on the western edge of the basin near the Goonyella open-cut coal mine (Figure 3.20). Four single-seam wells were drilled (only three were completed) and stimulated. Dewatering commenced in November 1987. In December 1987 and January 1988. 2 core wells were drilled (only 1 successfully) to obtain coal samples for testing. Five additional single-seam wells were drilled, completed, and stimulated beginning in February 1988. The last wells commenced dewatering in November 1988.

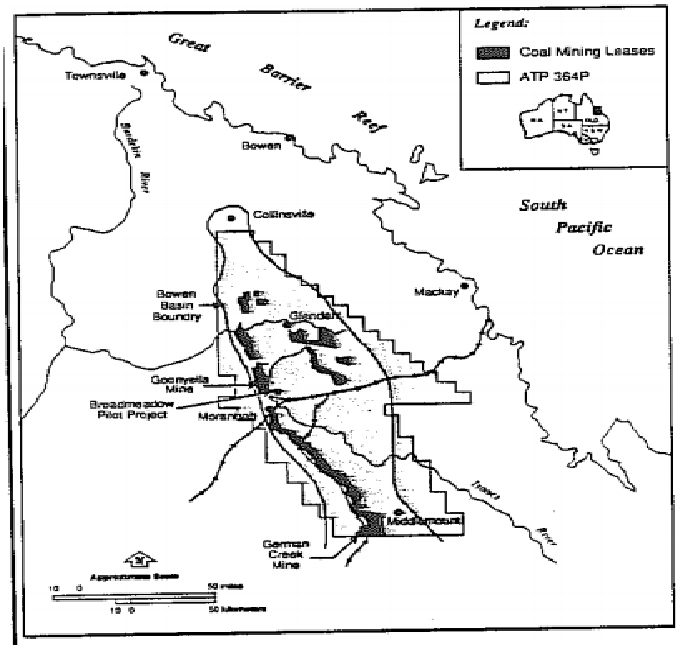


Figure 3.20 Location of ATP 364P in the Northern Bowen Basin

Source: Preliminary Renaults from the Broadmeadow Pilot, Project Bowen Basin, Australia

Efforts were also made at locating enhanced permeability regions of using techniques successfully applied in active U.S. basins, in particular, lineament studies. These techniques were proved ineffective however, because of thick Tertiary soil cover (an average of 268 ft. or 82m at Broadmeadow). A variety of new techniques are currently being investigated by CB Resources to assess their ability to detect enhanced permeability regions for coalbed methane production.

The resulting site selection was therefore a conservative one. Single-seam completions were chosen over multi-seam completions to reduce complexity.

The eight Broadmeadow production wells were completed in the Middle Goonyella seam (the same seam mined at the nearby Goonyella mine) which average 16.2 ft. in thickness and occurs at an average depth of 1640 ft. in the project area. The Middle Goonyella seam is a member of the Moranbah Coal Measure. Other members of the Moranbah sequence at Broadmeadow include the Upper Goonyella, the Goonyella Rider (or "P" seam) and the Lower Goonyella. Combined with the Middle Goonyella, these 4 coal beds range in thickness between 12.4 ft. and 16.2 ft. and have a combined total thickness of 557 ft. of clean coal over a gross interval of approximately 587 ft. Figures 3.21 illustrate the preliminary field structure map and total coal isopach maps respectively. There is a gentle dip (3.4°) to the ENE direction. An unforeseen fault on the eastern side of the pattern (presumably a reverse fault due to its orientation) with a displacement of nearly 200 ft. was inferred when the Middle Goonyella seam was encountered much shallower than expected in well no.7. This unexpected feature was the direct result of the lack of structural control and resulted in the miscompletion of well no.7 into the Lower Goonyella coal. Seismic studies have since been made prerequisites to drilling where a lack of structural controls exists. This is to avoid errors of a similar nature in the future. The coal isopach map for the Middle Goonyella coal shows a general thickening of coal to the ESE (Figure 3.22).

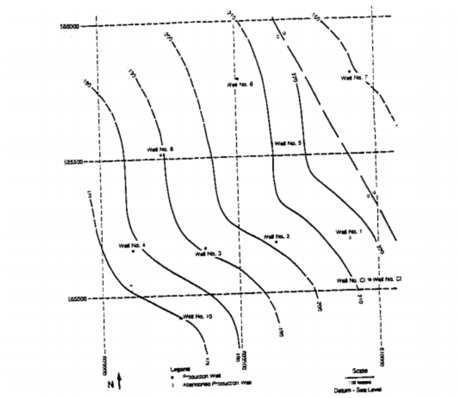


Figure 3.21 Preliminary Structure Contour Map-Middle Goonyella Seam

Source: Preliminary Renaults from the Broadmeadow Pilot, Project Bowen Basin, Australia

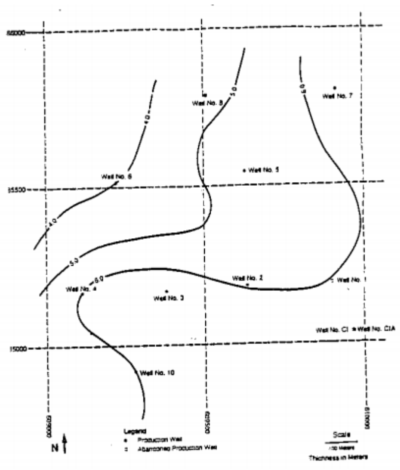


Figure 3.22 Preliminary Coal Isopach Map-Middle Goonyella Seam

Source: Preliminary Renaults from the Broadmeadow Pilot, Project Bowen Basin, Australia

Problem zones are known to exist in the Fort Cooper Coal Measures, which occur between 328 ft. and 1076 ft. in well no.1. The lower section of the interval below 689 ft. is where the re-entry problems began to occur. This area is comprised of a fine clastic sequence composed argillaceous siltstone, shales, coals and tuffs. It was thought at the time that using air as the drilling fluid was the cause of the hole instability and a decision was made to use only mud systems in the remaining wells. Obviously, with the loss of well no.1, 3 and 4 were the first 3 pilot wells.

These wells were hydraulically fractured in October 1987 using fresh water with volumes ranging between 141000 and 168000 U.S. gallons. The proppant used was 25/52 mesh Townsville sand and the columns ranged from 88000 to 110000 lbs.; the maximum sand concentrations achieved were either 1 ppg or 1 1/4 ppg. Conductivity testing of this proppant is currently underway to documented its properties so that it can be compared to other available propping agents.

The treatment rates varied between 34 and 37 BPM. No over flushes were used at any time during or at the end of these stimulations. Table 3.4 presents the fracture gradients observed as obtained from ISIP data. It is clear from these data that the Broadmeadow area (and presumably much of the basin as suggested earlier) is highly stressed. Furthermore, predominantly horizontal fractures appear to be the preferential geometry assuming that a vertical stress gradient of 1 psi/ft. exists. The coal seemed to accept the proppant readily, possibly indicating that the mechanisms sometimes used to explain high treatment pressure in coal (i.e., fracture tip plugging by coal fines/chips and parallel fracture effects), which are usually accompanied by a difficulty in pumping sand, may not have been a major factor in these treatments despite the high treating pressures.

Table 3.4 Fracture gradient information for well no. 2, 3, and 4

Well No.	**Initial Fracture Gradient(psi/ft)**	**Final Fracture Gradient(psi/ft)**
2	1.03	0.96
3	1.08	1.06
4	1.33	1.27

Source: Preliminary Renaults from the Broadmeadow Pilot, Project Bowen Basin, Australia

In February and March 1988, 5 additional wells were drilled at the Broadmeadow field. Well no.9 was never drilled because of exceptionally poor site conditions. With the addition of the 5 wells that actually were drilled, the average field spacing was raised to 36 acres/well.

Each well was prepared for fracturing by plugging back with sand to inside the bottom of the production casing. The annular area behind the uncemented casing could not be cost-effectively sealed, which left a total of 55 ft. of non-coal strata behind pipe exposed to the fracturing treatment. The wells were fracture stimulated in June 1988. Well no.6, 8, and 10 were fractured using water and well no. 5 was fractured using both 20 lb./1000 gal and 30 lb./1000 gal linear gels. Well no. 7 was not stimulated because it was isolated in another fault block and because it was completed into the Lower Goonyella seam. Each well was treated directly down the casing. Similar to the first 3 treatments, no overt lushes were used either during or at the end of the stimulations.

Well no. 5 was fractured using a 15000 gal 20 ln/1000 gal linear gel pad and 42000 gal of sand-laden 30 lb./1000 gal linear gel (Halliburton WG-11). The average pumping rate was 29

BPM and the average surface treating pressure was 1377 psig; the maximum sand concentration reached was 3 ppg. The proppant used was a 9/13 mesh Rockhamption sand, which similar to the Townsville sand, is mined and processed by CB Sand and Gravel Pty Ltd. Figure 3.23 compares the Rockhampton proppant to Ottawa 12/20 mesh sand at a concentration of 1.5 lbs./sq.-ft. and at closure pressure ranging from 500 to 2500 psig. Over this closure pressure range, the Rockhampton sand conductivity averages 78% of the conductivity average for the Ottawa sand.

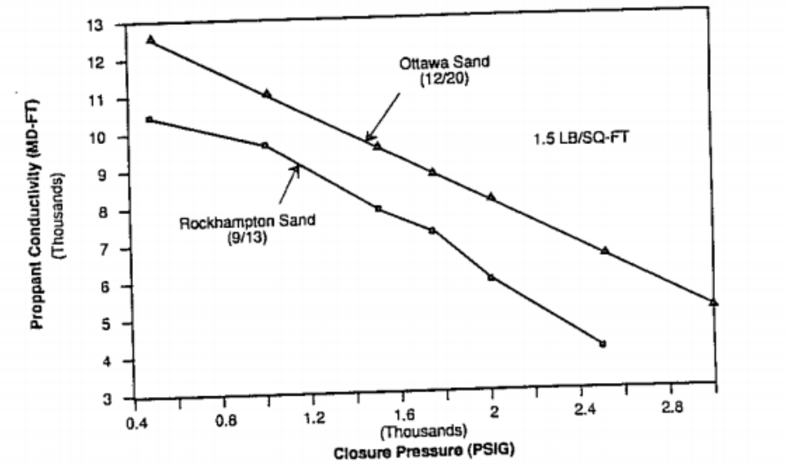


Figure 3.23 Proppant Conductivities foe 9/13 Rockhampton Sand and 12/20 Ottawa Sand

Source: Preliminary Renaults from the Broadmeadow Pilot, Project Bowen Basin, Australia

Well no. 6, 8, and 10 were fractured using water with volumes ranging from 169000 to 184000 gals and with 13/30 Rockhampton sand at volumes ranging from 97000 to 100000 lbs. The average treating rate varied between 37 and 41 BPM and the average surface treating pressure ranged from 1673 to 2329 psig. The maximum proppant concentration was either 1 or 1 1/4 ppg. The 13/30 Rockhampton proppant conductivities are compared to those of 12/20 mesh Ottawa sand at a concentration of 1.5 lbs./sq-ft. and at closure pressure ranging from 500 to 2500 psig (Figure 3.24). Over the entire closure pressure range, the Rockhampton sand conductivity averages 76% of the Ottawa sand value. This result is similar to that when comparing the coarser proppants.

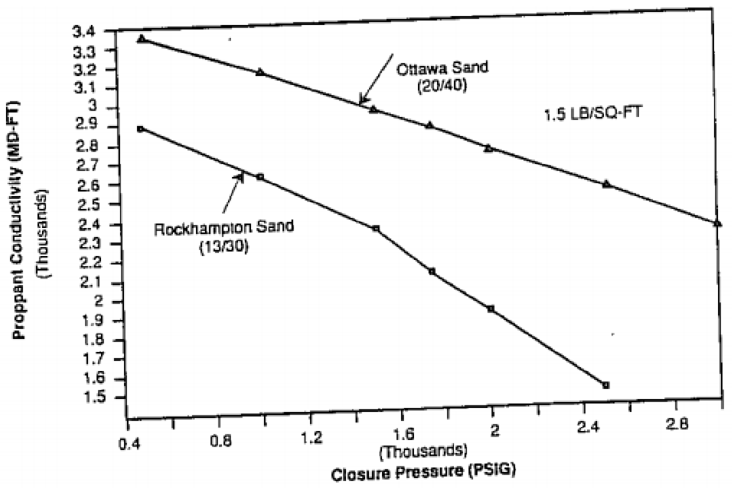


Figure 3.24 Proppant Conductivities foe 13/30 Rockhampton Sand and 20/40 Ottawa Sand

Source: Preliminary Renaults from the Broadmeadow Pilot, Project Bowen Basin, Australia

Fracture gradient information based on ISIP data for the four treatments are provided in Table 3.5. As expected, the fracture gradients consistently exceeded 1 psi/ft. The average initial fracture gradient was 1.17 psi/ft. and the average final gradient was 1.24 psi/ft.

Table 3.5 Fracture gradient information for well no. 5, 6, 8, and 10

Well No.	Volume Pumped(gals)	Fracture Gradient(psi/ft)
5	59000	1.15
6	184000	1.49
8	4000	1.21
8	176000	1.32
10	7000	1.13
10	169000	1.01

Source: Preliminary Renaults from the Broadmeadow Pilot, Project Bowen Basin, Australia

Production:

Two particular wells are reviewed in this section. Well no. 3 is reviewed because it is the middle, or interior, well from the first 3 wells and has a relatively long production history. Well no. 8 is also reviewed because it has the longest production history for any of the second 5 wells.

The production history for well no. 3 is given in Figure 3.25. The first six months of production was hampered by many problems, including stuck tubing, stocking rods and worn pumps. These occurrences in themselves do not normally create significant periods of downtime, but the effects were aggravated by a lack of workover rigs in the Bowen Basin area which resulted in downtimes of up to several weeks. Lack of proper well monitoring equipment also prevented regular well data collection. Only one gas meter was available for monitoring gas production and a well sounder to measure fluid levels was only available 3 months after pumping began. Even then data collection was intermittent. To worsen this, a cyclone rendered the field totally inaccessible for two weeks in March 1988. However, since May 1988, well production monitoring has greatly improved and non-pumping days have been substantially reduced. This is mainly a result of improved field procedures in terms of well maintenance and data recording. In late July/early August 1988, well no. 2, 3, and 4 were deepened by approximately 100 ft. to provide a more adequate rathole. This operation was successful in reducing the water-head on the Middle Goonyella seam by allowing deeper placement of the pumps in the wells. As of this time, however, no significant improvement in either gas or water production has been observed as a result of the operation.

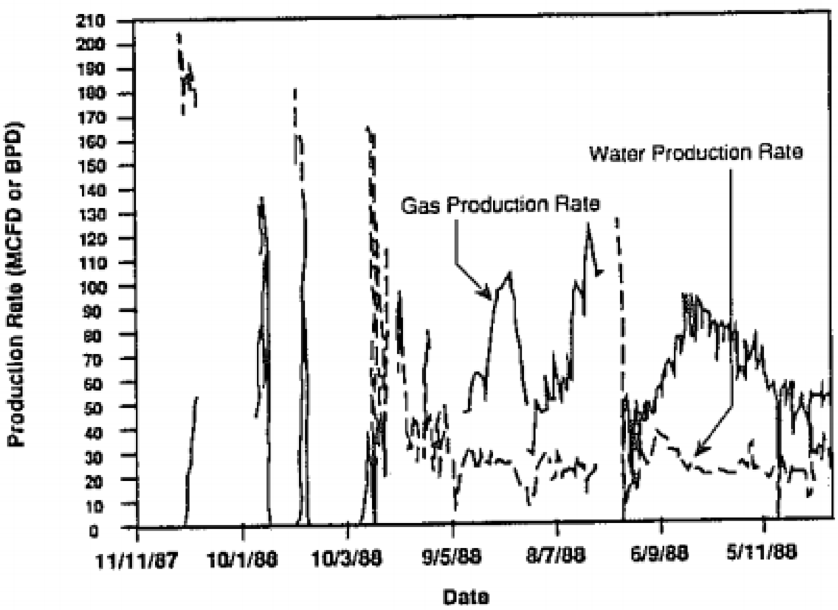


Figure 3.25 Production History for Well No.3

Source: Preliminary Renaults from the Broadmeadow Pilot, Project Bowen Basin, Australia

The production history for well no. 8 is given in Figure3.26. The methane production rate steadily improved from the initial well startup until a peak of approximately 50 Mcfd was reached. Both methane and water rates began declining primarily as a result of pumping problems which reduced water production volumes and hence allowed fluid level to rise. This in turn increased the bottom-hole pressure (due to water head), which combined with adverse relative permeability effects, reduced gas production. The pump problems ultimately resulted in a total loss of pumping capability for almost 3 weeks in November 1988. Pumping has since resumed with water rates exceeding 60 BPD.

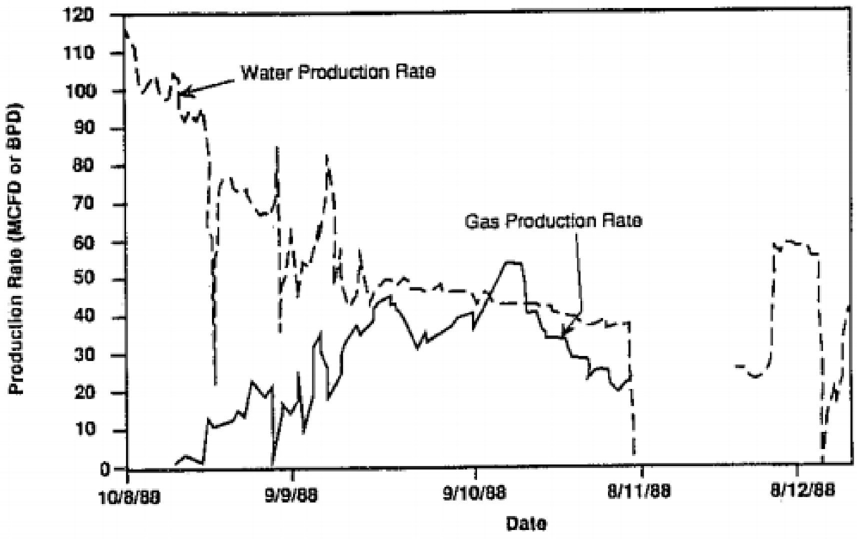


Figure 3.26 Production History for Well No.8

Source: Preliminary Renaults from the Broadmeadow Pilot, Project Bowen Basin, Australia

B. Successful Cases in US

In the process of fracturing treatment, the optimized total sand amount is divided into several stages. Each adding sand into fracturing fluids has a time interval. The most obvious difference between multistage sand fracturing and fracturing with slug sand is that fracturing with slug sand don't stop pumping during whole fracturing treatment. Figure 3.27 shows a well treated with proppant slug (Romero, J., Mack, M. G., & Elbel, J. L.,1995)

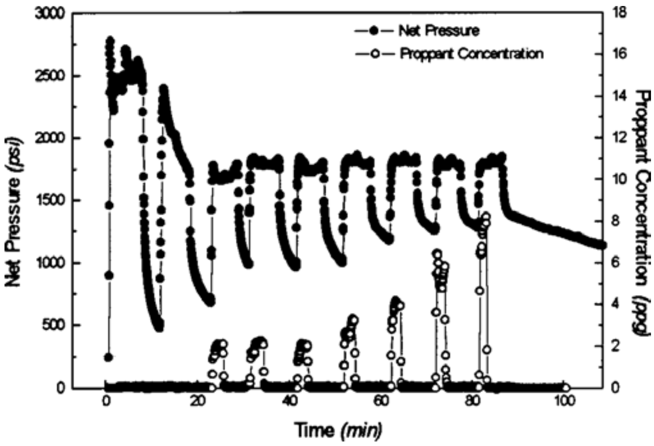


Figure 3.27 Well treated with proppant slug

Source: Romero, J., Mack, M. G., & Elbel, J. L.,199

3.3.1.2 Coiled Tubing Fracturing Technology

(1) Origin of the technology

The application of coiled tubing in fracturing operations first appeared in 1992. After more than ten years of research and field tests, the coiled tubing fracturing technology has developed rapidly. In addition to the conventional fracturing technology, it has also developed CT hydrajet fracturing technology and CT pinpoint fracturing technology, and the number of wells in operation has exceeded 10,000.

(2) Basic technique principle

The coiled tubing fracturing technology was developed to improve some of these processes after the success of the punctual perforating fracturing technology. The key to coiled tubing fracturing technology is the BHA (bottom hole assembly) (see Figure 3.28) that can perforate multiple layers of interest and seal effectively in a single wellbore.

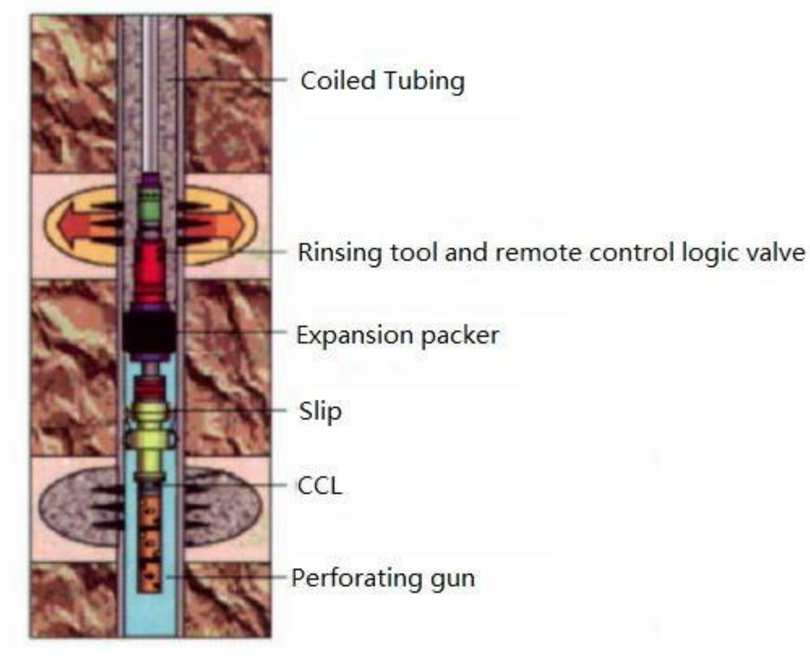


Figure 3.28 The key to coiled tubing fracturing technology

Source: New technology of coiled tubing fracturing, Yingsong Lin.

The general downhole tools are mainly placed on the coiled tubing. Inflatable packers are used to isolate the target layer and other target layers. Perforating equipment is a selective perforating gun. During operation, fracturing fluid is injected between the casing and the coiled tubing to provide energy for the hydraulic fracturing of the target layer.

Figure 3.29 shows a typical operating procedure for coiled tubing fracturing technology. The selective perforating gun in the coiled tubing fracture BHA is placed near the first target layer (the lowest layer in the layers to be stimulated, and the casing collar is used to control the depth), and then the perforating gun is detonated. Put the BHA under the target layer of the shot and place the slip and packer well. Fracturing fluid is injected into the formation through the annulus of coiled tubing and casing. When the stimulation operation is completed, the BHA is pulled up to a nearby layer adjacent to the next target layer. When the perforating gun is placed in the second target layer, the perforating gun is detonated, and after the perforating is completed, the BHA is lowered under the second layer, and place the slip and the packer well. Fracturing fluid is injected into the formation through the annulus of coiled tubing and casing.

The number of layers that can be operated in a single well depends on the perforating gun installed in the BHA. If the number of target layers to be operated is greater than the maximum number of layers for the perforating gun, remove the BHA from the wellhead, replace the perforating gun, and then enter to the next target layer immediately above the previous target layer to perform the operation. After all layers have been operated, working fluids can be produced by using downhole tools without requiring any special working fluid returning equipment. And then this well can start its production stage.

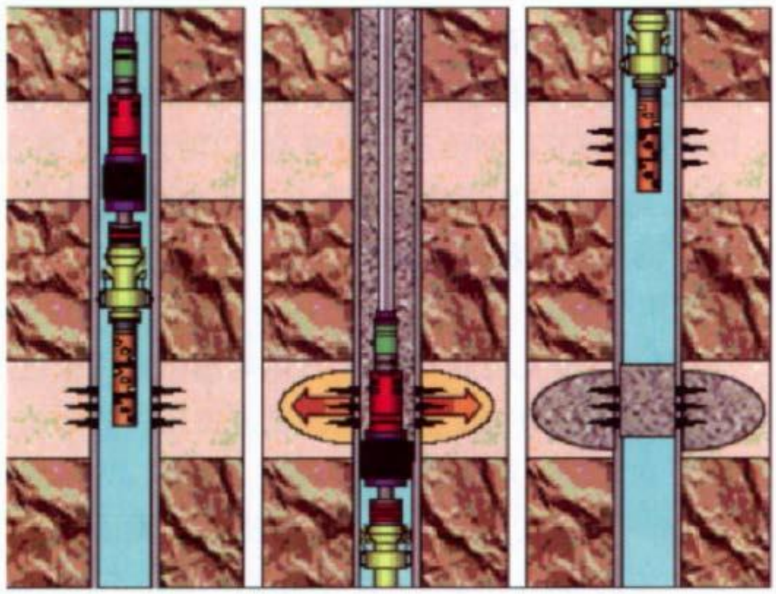


Figure 3.29 A typical operating procedure for coiled tubing fracturing technology

Source: New technology of coiled tubing fracturing, Yingsong Lin.

The coiled tubing fracturing process can achieve the non-permeability isolation of the operated layers and the operating layers. During the operation process, the technology uses a special packer at the target layer to allow the fracturing fluid to be continuously injected into the target layer. Thus, This can ensure that the layers previously operated are not contaminated, and the order of operations will not change.

3.3.1.2.1 CT Hydrajet fracturing technology

(1) Technique Principle

A multistage fracture stimulation method, Hydrajet fracturing, has been proven to be very successful for fracture stimulating horizontal wells. The process has been applied to open hole horizontals, horizontal slotted liners, and cemented-cased horizontal wellbores. The technique is essentially a combination of three processes: (1) hydrajetting to perforate; (2) through-tubing hydraulic fracturing while jetting, and (3) a separate fluid injection system down the annulus.

The process of quickly and efficiently fracturing multiple stages, begins with the coiled tubing and the BHA placed at the bottom of the well. A mechanical collar locator, contained in the bottom hole assembly (BHA), is used to correlate coiled tubing measured depth with previously recorded tally depth. The BHA is pulled up the well and positioned in the lower most CT Frac Sleeve assembly. Next the anchor and packer of the BHA are set and the pressure in the well above the packer is increased. This creates a pressure differential across the packer. This pressure differential also acts on the valve contained in the CT Frac Sleeve assembly. Once the pressure differential reaches a predetermined value, typically 20 MPa, the valve in the CT Frac Sleeve assembly opens. Once the valve is open, the BHA remains set in position, and fracture stimulation operations begin. The stimulation fluid is pumped down the well bore annulus, exiting the completion through the fracture ports, located above the packer. Once the fracture fluids are pumped, the BHA is unset, moved up the well to the next CT Frac Sleeve assembly and the process is repeated as required to stimulate all the stages in the well.

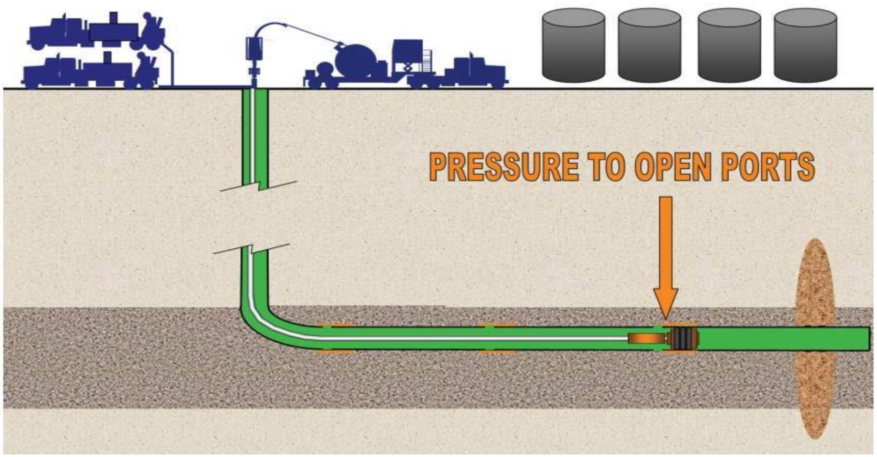


Figure 3.30 The process of CT Fracturing

This patented method uses dynamic sealing methods using the Bernoulli principle. In the hydrajet fracturing process, the term “dynamic sealing” is, as a seal was never placed or used in the process. In reality, the “seal” represents prevention of the fluid of the jet from flowing outwards away from the jet. In other words, it does not prevent fluids to flow inwards towards the jet area. This technology is defined by Daniel Bernoulli in his book, Hydrodynamical, in 1738. (Bernoulli, al 1738) (A similar publication with a similar title was published about the same time by Johann Bernoulli, Daniel’s father). In essence, the Bernoulli equation can be simplified as:

$$V2/2 + P/\rho = \text{Constant} \quad (1)$$

Where V is the fluid velocity, P is pressure, and ρ is density.

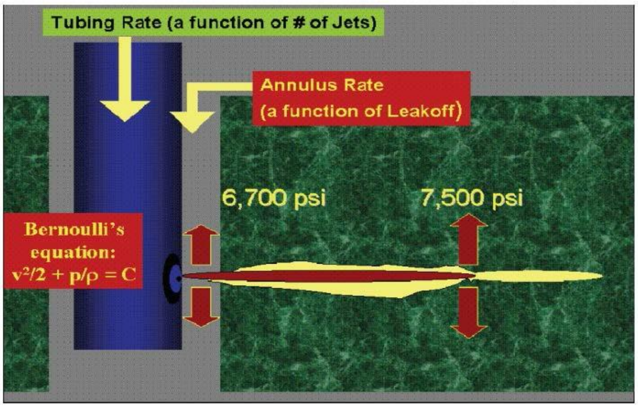


Figure 3.31 Hydrajet fracturing concept explained

(2). Advantages and disadvantages

Advantages: Compared with conventional tubing conveyed hydraulic fracturing, CT hydraulic fracturing has a number of advantages. In particular, CT provides the ability to quickly move in and out of the hole (or be quickly repositioned) when fracturing multiple zones in a single well. CT also provides the ability to fracture or accurately spot the treatment fluid to ensure complete coverage of the zones of interest when used in conjunction with appropriate bottom hole assembly tools such as straddle packers. This is particularly important for stimulation of multiple zones or bypassed zones or horizontal wellbores. At the end of the formation treating operation, CT can be used to remove any sand plugs used in the treating process, and to lift the well to be placed on production.

Stimulation techniques involving coiled tubing (CT) deliver improved efficiencies in horizontal completions because of the ability to instantly address contingencies by having CT in the hole throughout the operation. This method enables accurate fracture and proppant placement, as these operations typically focus on placing one fracture at a time. Isolation is commonly achieved using sand plugs, which have demonstrated to be especially effective; however, when fracture intensity is applied, sand plugs might not achieve the spacing required. This is because of the length of sand plugs often necessary to achieve isolation. Also, the time to set sand plugs can be considerable if they do not properly set the first time.

Disadvantages: Pump speed is limited. CT strings have small tubing diameter - small enough so that adequate tubing length can be spooled onto the coiled tubing reel. This limits the cross-sectional area open to flow. Furthermore, the tubing curvature causes secondary flow and hence results in extra flow resistance (Zhou et. al 2004). Therefore, fluid frictional pressure losses in CT hydraulic fracturing are much higher than those associated with conventional tubing fracturing (Gavin al 2000).

Hydraulic nozzles have a short life. In the conventional HJ-Frac operation process, a set of 9 nozzle injection tools pump about 250t of proppant and have to be replaced; if the injection rate is considered to increase and the number of BHA nozzles is reduced, the corresponding processing volume will be lower, during the injection process. The degree of erosion of the nozzle will be more severe and its life will be shorter.

Fracturing fluid concentration ratio is limited. Due to the need to ensure that a certain amount of low-velocity fluid reaches the bottom of the well during the filling process, the fracturing fluid concentration in the operating string must be designed to be twice the downhole concentration and mixed with part of the annulus fluid to reach the required concentration for sand carrying. However, when the ratio of pump fracturing fluid concentration is too high, the corresponding proppant concentration design is limited, resulting in a lower concentration of proppant into the fracture than the proppant concentration required to achieve effective fracturing (Haitao Wang,2010).

(3). Case study

Case in Canada. It is difficult to ascertain when the first coiled tubing fracture treatment took place but a job was carried out in south-eastern Alberta (McMehan et. al 1994) in February, 1993 where a 25 tonne treatment was pumped through 73.0 mm (2-7/8 inch) coiled tubing at 3.0 m^3/minute (18.9 bbl./min). The procedure was similar to that performed today with the exception that the coiled tubing was stung into a permanent packer.

As of year, end 1999 approximately 700 wells have been fractured industry wide using coiled tubing as a conduit. The number of zones per well varies from 1 to 8 and the total number of fracture treatments performed on these 700 wells is over 5,100. This technology has been predominantly limited to the shallow gas fields of southeastern Alberta.

3.3.1.2.2 CT PinPoint Fracturing Technology

(1) Technique Principle

The PPF technology refers to the use of special tools for coiled tubing, combined with well logging data, to accurately determine the horizon to be fractured, and to operate it efficiently. When the logging section of the coiled tubing fracture is completed, the depth measured by the coiled tubing depth gauge is corrected. The tool is changed from logging mode to fracturing mode, and the fracturing operation can be performed. First, create perforations by pumping abrasive slurry down the coil tubing through a jetting nozzle while the main treatment is then pumped down the annulus around the coil tubing. Isolation between fracture treatments is accomplished using sand plugs (preferred method) or composite bridge plugs.

(2) Technical advantages and disadvantages

Advantages: Pinpoint fracturing technology allows multiple precisely-targeted fracs to be economically treated, which can increase flow rates and reserves, reduce incremental per-frac costs and significantly shorten cycle time compared to multi-stage conventional treatments. And this technology can effectively stimulate multiple intervals in a wellbore quickly and economically. Similar experience has been observed in other areas, in which PPF technology has improved fracture coverage and field performance. By controlling the initiation point, the fracture height and length can be better predicted. This in turn causes improved productively from each wellbore through more effective stimulation of all target intervals.

Disadvantages: Current Challenges No Breakdown. It is clear that the inability to breakdown intervals using the PPF technique is a major concern. Currently breakdown problems have been observed in 6% of PPF attempts, however extremely few of these intervals have shown production following conventional post-frac perforating. Perforating the intervals using conventional guns has enabled successful breakdown and treatment placement when point source jetting has been unsuccessful. This is due to differences between point source fracture initiations with the PPF technique as compared to breakdown through larger (5-10 ft) conventionally perforated intervals. With this in mind some future developments are underway to overcome these PPF breakdown limitations. These involve using larger coil to enable higher jetting rates facilitating more jets staggered over a larger interval.

(3). Case Study

The first case:

Eight wells in the Cooper Basin of Australia have been Pin-Point stimulated using coiled tubing. Cooper Basin reservoirs commonly contain low-permeability reservoirs that require stimulation to flow. However, conventional multi-layer stimulation techniques have been shown to leave some sands untreated and not contributing, leaving potential to further increase flow rate and reserves through the use of new technology.

Fracturing step:

Minifrac Injections.

For each of the zones, a minfrac injection was performed prior to fracture stimulation. The initial injection breakdown sequence used 3000 gals of 35# linear gel. The zone broke down at 8600 psi with the acid and cutting sand being injected into the formation at 15 bpm.

Main Fracture Treatment

The main fracture treatment of stage 1 was pumped with a 35# cross linked borate system based on a BHT of 250 to 270 °F and 20/40 Bauxite. The job design was not modified after the minifrac results. The design called for 31000 lbs. of 20/40 Bauxite in stages up to a maximum of 6 ppg with 21500 gals of fluid. The treatment pumped to completion with a net pressure rise of 300 psi. The treatment for stage 2 utilized the same fluid and proppant systems. The design called for 40000 lbs. of 20/40 Bauxite which was unchanged.

MPL

Following coiled tubing clean out and extended clean-up flow, a post-stimulation Memory Production Logging Tool (MPLT) was run (Figure 3.32). Track 1 shows GR and caliper, track 2 depth, track 3 porosity and water saturation, track 4 lithology, track 5 temperature and track 6 spinner. The log was run before any additional post fracturing perforations were added or the final completion was run.

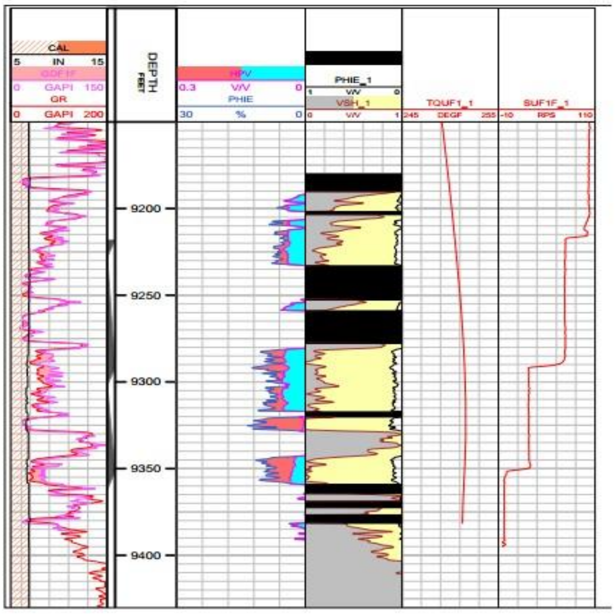


Figure 3.32 Case History 1 MPLT Results-Well 3

Source: Applications of Pinpoint Fracturing in the Cooper Basin, Australia

Fracturing effect of PPF Treatments:

Eight wells in the Cooper Basin of Australia have been Pin-Point stimulated using coiled tubing producing a 30% increase in well productivity compared with AFE expectations. Production logs run over the fractured zones show markedly improved completion efficiency with production from the majority of Pin-Point fractured zones.

Table 3.6 Well Summary

Well	Isolation Technique	Zone Depth	Pin Point Zones
1	Packer	9384-9756ft	4
2	Packer	7869-9579ft	6
3*	Packer	9218-9350ft	3
4	Packer	9275-9851ft	4
5	Sandplug	7770-8370ft	3
6	Sandplug	7185-7842ft	5
7*	Sandplug	8807-9561ft	4
8	Sandplug	8786-9930ft	5

Source: Applications of Pinpoint Fracturing in the Cooper Basin, Australia.

The second case:

Over 145 pin-point fracturing (PPF) treatments have been performed in Australia's Cooper Basin since the introduction of the technology in mid-2004.

Prior to the introduction of PPF, single treatments were commonly performed through multiple perforated intervals (hereafter termed "blanket fracturing"). Analysis of post-frac production logging tests (PLT) suggest this technique does not effectively stimulate multiple intervals, bypassing significant reserves.

Fracturing step:

Following the initial eight wells slight procedure modifications have been trialed to optimize PPF operations. This has built a strong database of information which has led to the process utilized today. The present PPF procedure sequence for each zone - including the jetting, formation break down, main treatment stimulation and isolation pressure test - is outlined below.

- Run coiled tubing (coil) and correlate on depth using marker joints and collars for the first fracturing target.
- Pump down coil a 1 lb./gal 20/40 sand slurry and displace to provide at least 10 minutes of abrasive jetting to cut perforations.
- Pump down coil a volume of 15% HCL and displace leaving acid spotted partially into the annulus.
- While maintaining the coil rate, shut in the annulus and squeeze the remaining acid into the formation until breakdown is achieved.
- Once breakdown is observed, begin injection down the annulus to desired treatment rate. Simultaneously reduce the coil rate to a minimum to provide a dead string and maintain a positive pressure during injection.
- Complete diagnostic fracture injection test (DFIT), displacing all remaining acid and cutting sand into the formation. Perform step-down test at the end of the injection to evaluate the near wellbore pressure loss (NWBPL).
- Monitor decline to determine the closure stress, leak-off behavior, reservoir pressure and formation permeability, if cycle times permit.

- Pull coil up to next jetting depth and pump the main treatment. Continue breaker but drop crosslinkers and commence a 6-10 lb./gal proppant ramp.
- Drop breaker and completely flush with linear gel, dropping rate to induce a screen-out as the final proppant ramp reaches formation.
- Should a screen-out occur, reverse out excess proppant with the coil still at the next cutting depth. If a screen-out does not occur, the final flush includes a slight under-displacement to provide a sand plug.
- Pressure test sand plug to 10,000 psi. Should test fail reverse down and spot a secondary sand plug for isolation. Note: if plug fails a second time the wellbore is cleaned out and a mechanical plug set.
- Once isolation of lower zones is achieved the process is repeated.

Fracturing effect of PPF Treatments:

Thirty wells have been completed using PPF technology since its introduction in Mid-2004, comprising approximately 50% of all the wells stimulated (see Figure 3.33) during this time period. For the full review of the Cooper Basin fracturing activity, refer to Mc Gowen et al. PPF technology has been used in almost all instances when more than 2 treatments have been performed per well and are otherwise not economically justified when performing 1 or 2 fractures per well.

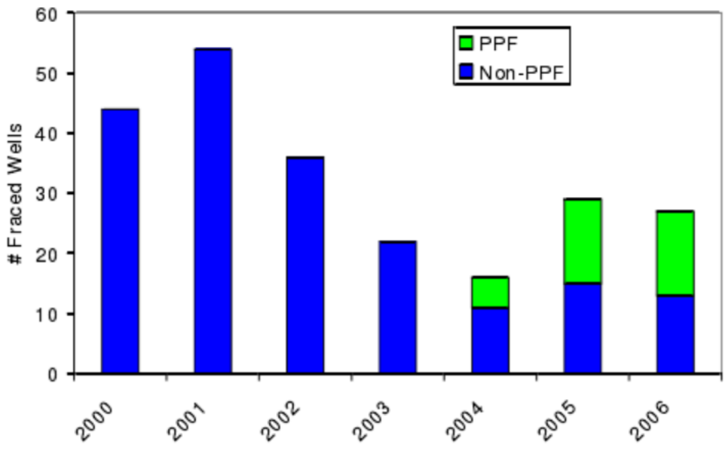


Figure 3.33 History of fracturing wells

Source: Pin-Point Fracturing (PPF) in Challenging Formations

The trend of individual fracturing stages in presented in Figure 3.34. A total of 149 treatments have been completed in the 30 wells, giving an average of ~5 PPF treatments per well. A total of 61 treatments were completed during 2004-2006 in the 36 Non-PPF wells, giving an average of ~2 fractures per well.

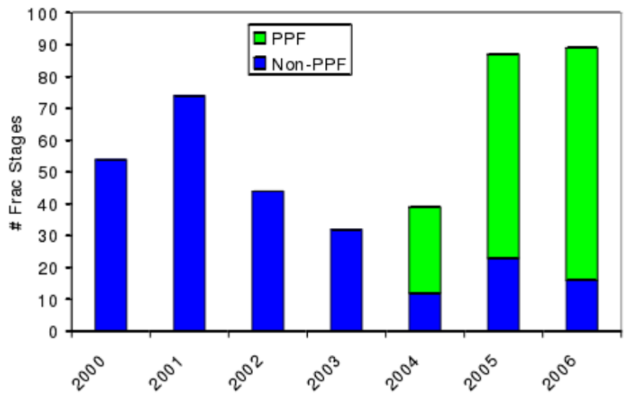


Figure 3.34 History of fracturing stages

Source: Pin-Point Fracturing (PPF) in Challenging Formations

Post-frac production results from the PPF and Non-PPF wells are presented shows the average post-frac production rate on a yearly basis from 2000 to 2006. This post-frac rate is determined after the well has been cleaned up and produced in-line for at least 1 month after running production tubing (typically 2 3/8" for the PPF wells). The Non-PPF wells have produced at a post-frac rate of ~2-4 MMscf/day (on average), while the PPF wells are producing at a rate of ~5-6 MMsf/day. The only exception is the 2004 Non-PPF value of ~6 MMscf/day which was due to two exceptional producers in this low activity year.

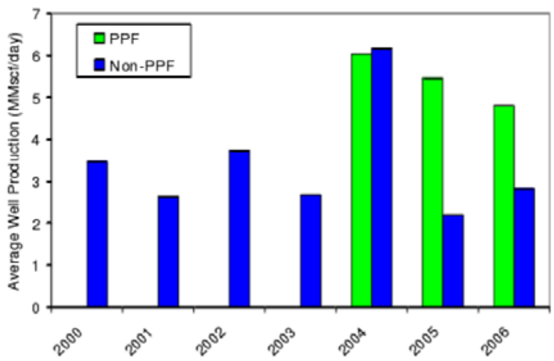


Figure 3.35 Average production response

Source: Pin-Point Fracturing (PPF) in Challenging Formations

The recoverable reserves estimate presented in Figure 3.36 are approximations due to present limited production history from many of the PPF wells. Non-PPF experience has indicated recoverable reserves per well ranging from 2-6 bcf, with high variability. Although uncertain at this time, the recoverable reserves of the PPF wells are predicted to range from 4-8 bcf, with similar variability. It is hopeful that the PPF predictions are conservative and that larger reserves will be observed due to continued performance of the lower permeability intervals.

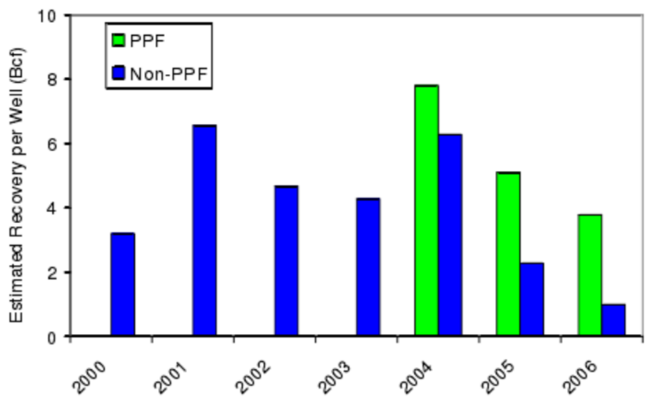


Figure 3.36 Average Estimated Recovery

Source: Pin-Point Fracturing (PPF) in Challenging Formations

3.3.1.3 N_2 Fracturing Technology

(1) Technical Principle

Because N_2 is the least strongly adsorbing component, CH_4 desorption is achieved through the reduction of the partial pressure of CH_4 in the mobile-gas phase. A bank of CH_4 is created at the leading edge of the displacement. As the displacement proceeds, CH_4 desorbs, adding volume to the flowing vapor phase (Seto et al., 2009). This results in an increase in local flow velocity and an accelerated production of CH_4. Because N_2 is the least strongly adsorbing component and also the least soluble in the water phase, N_2 propagates quickly through the system and is produced simultaneously with CH_4 for an extended period. Hence, for spreading wave displacements, the composition of the produced gas is a mixture of N_2 and CH_4.

As nitrogen is injected into a coal reservoir, it's lowering the partial pressure of methane, accelerating desorption and recovers the methane gas. Through this process the majority of nitrogen would be produced along with recovery of CMB and needed gas processing (Luca Gandossi., 2013).

(2) Advantages and disadvantages

A. Advantages:

- No dewatering or artificial lift needed, since some formations (like the Horseshoe Canyon coals in Alberta) are dry, dewatering are unnecessary.
- Reduce formation damage, Self-propping fractures can be created by the thermal shock, hence need for proppant reduced or eliminated.
- Due to no proppant being used, these treatments never “sand off” eliminating the risk of an expensive well bore clean out.
- All of these factors make CBM well much more economic.

B. Disadvantages:

- There is, however, one major drawback associated with injecting N_2—it tends to lead to early breakthrough at the production wells, which would cause deterioration in the quality of the produced gas.
- Nitrogen is a very common component of the atmosphere. But, the need to use special pumping and handling equipment will increase costs.

(3) Case Study

A. Case Study 1 Canada:

In Alberta, Canada, the Horseshoe Canyon coals are very different from the coals of a typical CBM basin like the Powder River, and have several unique and important characteristics, including:

- 10 to 30 or more thin seams, rather than one, or a few, very thick seams
- Broad depth (and completion) interval
- Dry coals (no water in the cleats)
- Severe under-pressuring

Without water or some other viscous fluid, it could not transport proppant into the coal seams to stimulate the wells. Finally, it was difficult to effectively stimulate (conventionally) the large number of open coal intervals in a typical Horseshoe Canyon well.

Recognizing the damaging effects of liquids on these coals and the practical limitations of conventional stimulations, it turned to a technique that had been used previously in the Appalachian Basin: high-rate, dry nitrogen injection stimulations. By using coiled tubing units equipped with a down hole fracturing isolation tool, we could individually treat each of the open coal seam intervals in a well, ensuring that every completion interval received some amount of stimulation.

This figure shows that the initial “breakdown” treatment resulted in some gas flow from the coals in the well, but that the subsequent high-volume, high-rate treatment resulted in a 250% productivity increase. We applied this two-step stimulation technique to most of the wells in our initial exploration program and saw productivity gains of 200% to 400% as a result of the second stimulation treatment. Eventually, we dropped the “breakdown” treatments from our completion program, and currently perform only the high-volume, high-rate nitrogen stimulations to complete our wells.

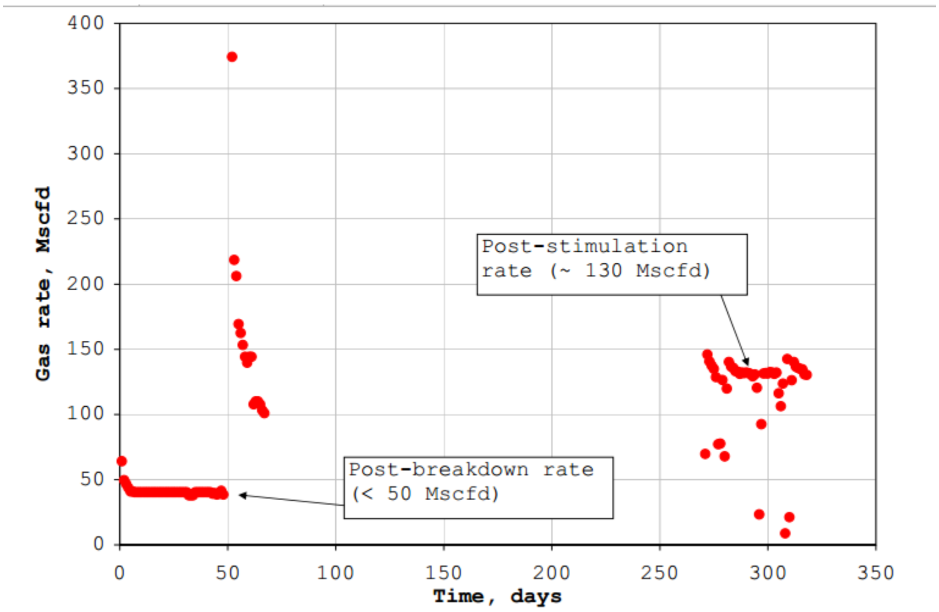


Figure 3.37 Example comparison of production performance after “breakdown” and stimulation

B. Case Study 2 in Australia:

An example of Nitrogen foam fracturing [M. Badri, 2000]

Fracture Fluid Selection In coal reservoirs, the interaction of the coal with stimulation fluids is a critical design factor which is often under-emphasized. Bowen basin coals10 in general, exhibit a unique set of microlithotype, tectonic, cleat and mineralization characteristics which require specific design consideration. A well-engineered stimulation treatment requires the chemical optimization of the fracture fluid based on coal characteristics and settings.

Given the location of the gas saturated target coal intervals in the gas cap of the subject Peat wells, procedures were planned to minimize the introduction of liquids into the coal cleats. This objective could be accomplished by the use of a nitrogen foamed fracture fluid.

Nitrogen foam with minimal surfactant loading and gel content could achieve the required foam rheology under downhole treating conditions. Because of the high free gas content of these coals, the higher gas content of a nitrogen foam treatment fluid could help minimize potential detrimental aqueous fluid saturation and relative permeability effects in addition to enhancing methane desorption. An additional incentive for a foamed system resulted from the fluid efficiency afforded by a foam fluid. The high efficiency fluid was strongly recommended based on the estimated moderate permeability coupled with the pressure dependent leak-off of the coal intervals considered for stimulation. The lower leak-off of the nitrogen foam fluid helped ensure that the minimum fluid requirement needed to create the fracture geometry to improve the gas production. Treated water with a base salt concentration of 2% potassium chloride (KCl) was used to minimize clay dispersion related to ionic depletion. The 2% KCl treated water was used to determine injection pressures, and stress magnitude, as well as estimate the tortuosity effects through the use of Stepdown Rate Tests23 (SDRT). This fluid was also used to carry the proppant during the sand slug stage3,5 which preceded the main fracture treatments. The p H of the pumped fluids was buffered to the range of the 4 to 5 to reduce precipitation of potential carbonate scales and to assist in gel clean-up10. To minimize fluid retention, and contact with the coal over time, well clean up of all the treated intervals was conducted at night time following the treatment under controlled flow-back until the pressure was dissipated prior to running the composite bridge plug to isolate each well.

C. Conclusion:

The use of composite plugs resulted in a safe, more efficient and cost-effective way to carry out staged nitrogen foam treatments and complete and produce the wells in record time. Up to two foam fracture treatments were carried out per day despite the limited nitrogen supply through the use of this stimulation approach thus minimizing the service delivery and workover time, and hence lowering the cost of each well completion.

Past experience in the Peat area coupled with the proper fracturing fluids selection, the use of real time fracture analysis and process improvement led to a very successful stimulation campaign in achieving good gas production rates at a reduced cost. Analysis of the pre-fracture injection/breakdown tests using the G-function derivative approach helped identify the leak-off mechanism and estimate the closure pressure of each coal interval. The net pressure history match of the treatment data is achieved through the use of multiple fractures in a 3D fracture simulator for most cases based on evidence from mine back experiments though "tip effects" may contribute to the increased net pressures to a certain extent.

The decrease in treating pressures past a "critical" sand concentration when pumping sand laden fluids is believed to be due to "screen-out" of secondary fracture branches and to certain extent caused by the erosion of perforation tunnels with time.

More importantly this approach has resulted in a technique that more than competes with the cavity completion that was carried out on earlier wells in this field either in terms of production enhancement or completion cost.

The high rate nitrogen foam fractures also resulted in the successful creation of efficient propped fractures that gave rise to the excellent production for the different wells treated. Moreover, the success of the stimulation treatments was confirmed by the post-fracture production tests carried out on the selected Peat wells that showed a high negative skin.

The high rate nitrogen foam fracturing of the Peat Wells resulted in methane production rates of up to 5 MMscfd.

3.3.1.4 CO_2 Fracturing Technology

(1) Technical Principle

Because CO_2 is preferentially adsorbed relative to CH_4, as the more strongly adsorbing CO_2 propagates through the coalbed, it is removed from the mobile phase, creating a self-sharpening displacement (Seto et al., 2009). Replacement of CH_4 by CO_2 on the coal surface creates a fast-moving bank of CH_4 and H_2O that propagates downstream, followed by a slow-moving CO_2 bank (in which H_2O is also flowing). The ratio of the volume of CH_4 desorbed to the volume of CO_2 adsorbed is less than unity, resulting in a net decrease in flow velocity (Furqan Hussain and Yildiray Cinar., 2013). Because of the unfavorable mobility ratio between water and the injection gas, breakthrough occurs at low gas saturation. A slow-moving, trailing evaporation shock occurs at the upstream end of the displacement to connect the solution to the injection composition. The low volatility of H_2O in the gas phase requires that a large amount of gas be injected to evaporate all the H_2O.

During fracturing operations, CO_2 is injected into the water phase of the fracturing fluid (usually gelled) below the critical temperature as liquid and creates an emulsion type fluid after this mixing. The entirety of the proppant will be mixed into the gelled water phase, which typically is only 30–40% of the surface blend, so surface mixing equipment will need to handle high proppant concentrations. After it heats beyond its critical temperature it becomes a highly compressed gas and converts from an emulsion to a foam. However, at the pressures of most fracturing operations it is in a super compressed gas form and its density and volume do not drastically change at high pressures such as the bottom hole treating pressure (BHTP) present during pumping time. Due to cool-down of the treatment tubulars this normally will occur after the emulsion enters the fracture. After the treatment, when pressure is lowered to induce fluid returns CO_2 flows back as and expanding gas, together with the formation and fracturing fluids. These stages are depicted by the numbered descriptions in Figure 3.38.

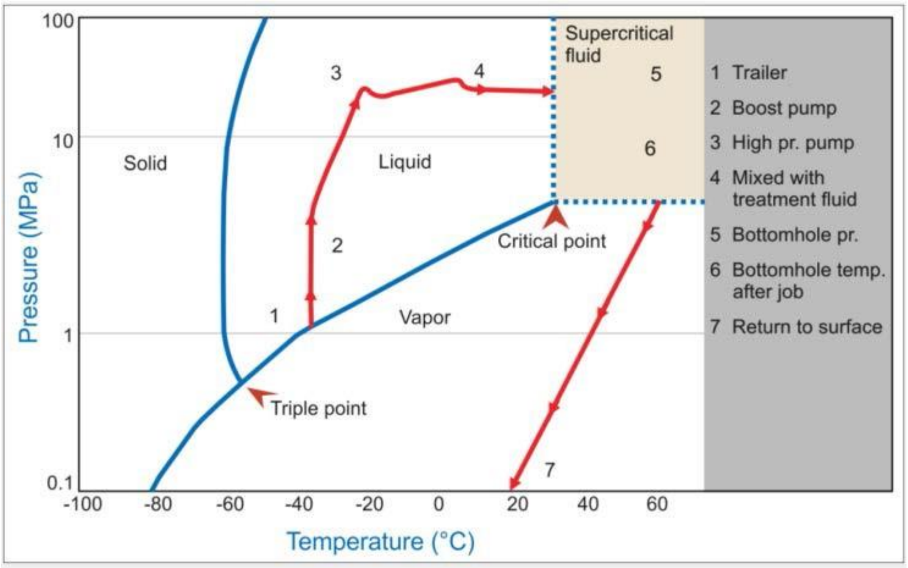


Figure 3.38 Phase diagram of CO_2 (and identification of CO2 pressure-temperature condition during use of CO_2 and identification of CO_2 pressure-temperature condition during use in hydraulic fracturing.

Source: Mohammed Al-Dhamen,2015

(2) Advantages and disadvantages

A. Advantages:

- Some level of CO_2 sequestration achieved.
- Reduction of formation damage (reduction of permeability and capillary pressure damage by reverting to a gaseous phase; no swelling induced).
- Form more complex micro-fractures, which can connect many more natural fractures greatly, increasing maximally the fractures conductivity.
- Enhance gas recovery by displacing the methane adsorbed in the formations.
- Evaluation of a fracture zone is almost immediate because of rapid clean-up. The energy

provided by CO_2 results in the elimination of all residual liquid left in the formation from the fracturing fluid.

- Better cleanup of the residual fluid, so smaller mesh proppant can be used and supply adequate fracture conductivity in low permeability formations.
- The use of low viscosity fluid results in more controlled proppant placement and higher proppant placement within the created fracture width.
- Water usage much reduced or completely eliminated.
- Few or no chemical additives are required.

B. Disadvantages:

- The main disadvantages follow from the fluids' low viscosity. Proppant concentration must necessarily be lower and proppant sizes smaller, hence decreased fracture conductivity.
- CO_2 must be transported and stored under pressure (typically 2 MPa, -30°C).
- Corrosive nature of CO_2 in presence of H_2O.
- Unclear (potentially high) treatment costs.

(3)Case Study

A. Case in Canada

The Alberta Research Council (ARC) is performing a project entitled "Sustainable Development of Coalbed Methane; A Life-Cycle Approach to Production of Fossil Energy" that is funded by an international consortium of companies. The main objectives of the project are to reduce greenhouse gas emissions by subsurface injection of CO_2 into deep coalbeds and to enhance coalbed methane recovery and production rates (Mavor et al., (2004). We have performed extensive field tests that includes efforts on two wells located near the towns of Fenn and Big Valley in Alberta that penetrated Medicine River (Mannville) coal seams.

Initial CO_2 Injection We had no previous experience with CO_2 injection into Medicine River coal seams and we planned a single injection test to ensure that injection was possible. Bottom-hole transducers were installed and liquid CO_2 was injected at between 100 and 132 liters per min. 21 metric tons (20 m^3) of liquid CO_2 were displaced into the well. The CO_2 vaporized in the well and an estimated 18 metric tons (17 m^3) were injected into the coal. CO_2 vapor volume is 542.8 m^3 at standard conditions per m^3 of liquid, therefore 9,230 m^3 of CO_2 vapor were injected into the coal. The final surface injection pressure was 1,500 kPa(g) with a bottom-hole pressure of 10,200 kPa(a). A four-day fall-off test followed injection. Because of the low injection rate, the minimum bottom-hole temperature during injection was 42.8 ^oC. not greatly reduced from the static temperature of 47.1 ^oC. and did not affect the transducer.

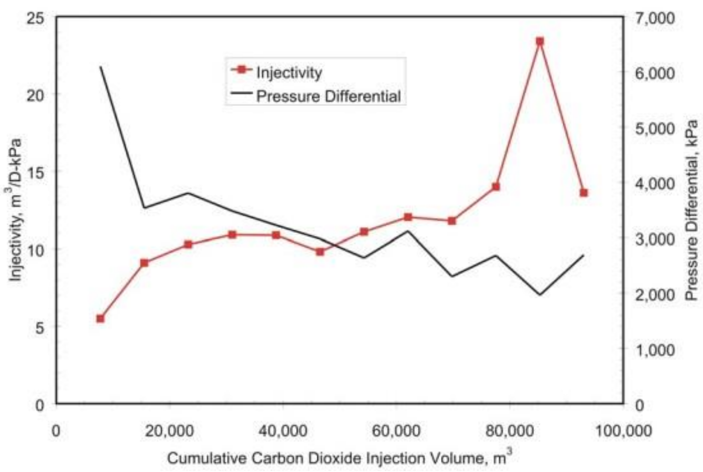


Figure 3.39 CO_2 Injectivity

As all of the injected fluid was in the vapor phase, the falloff period analysis was based on the real gas potential5 approach. CO_2 vapor properties were computed with equation of state software. Although the data were erratic due to wellbore effects, it was possible to evaluate the data. Injection of CO_2 apparently created or opened existing fractures. The effective permeability to gas estimate (0.632 mD) was similar to but slightly greater than the pre-CO_2 estimate of 0.529 mD. A skin factor of -4 (equivalent to a fracture half-length of 9 m) matched the data.

Post-CO_2 Production Testing After the falloff test, FBV 4A was returned to production to determine the effect of the CO_2 upon productivity and reservoir properties. The well stabilized to a tubing head pressure of 160 kPa(g) and a gas rate of 3,200 to 3,300 m^3/D. 14,635 m^3 of gas were produced over a four-day flow test. This volume was 1.58 times greater than the injected volume of CO_2. The cumulative CO_2 produced was 4,205 m^3, 46% of the injection volume. The first produced gas composition was 100% CO_2 as all gas originated from the well. After 2.2 hours, the gas composition was 55.4% C_1, 0.8% C_2, 40.8 CO_2, and 3.0% N_2. At the end of the production, the composition was 77.6% C_1, 1.2% C_2, 16.6% CO_2, and 4.7% N_2.

Analysis of following shut-in period data resulted in essentially the same estimate of absolute permeability (3.47 mD) as the estimate obtained from shut-in test data prior to CO_2 injection (3.65 mD). The skin factor estimate was 2 indicating that the stimulation caused by CO_2 injection was reversed to the original pre-injection level.

Extended CO_2 Injection Once CO_2 injectivity was determined to be sufficient, larger scale CO_2 injection commenced. 180 metric tons of liquid CO_2 were injected during 12 separate injection periods over 31 days. 15 metric tons were injected during each of the 12 injection periods equivalent to 7,750 m^3 of vapor. Injection time ranged from 4 to 7 hours at approximate injection rates of 30l/min. After 12 injection periods, the total vapor volume displaced into the wellbore was 93,050 m^3 of which 91,500 m^3 were injected into the coal seam. Bottom hole injection pressures declined from 14,000 to 10,600 kPa(a). The falloff periods were not designed to obtain reservoir property estimates as no attempt was made to minimize wellbore effects. However, we evaluated each of the falloff periods by history matching the observed pressure changes and derivative behavior with a wellbore storage and skin model.

In general, with some exceptions probably due to analysis problems caused by wellbore effects, the effective permeability to gas decreased with continued injection while the skin factor became progressively more negative. The effective permeability to gas decreased from the pre-injection estimates of 0.53 mD to 0.24 after injection of 91,500 m3 of CO_2: a decrease by a factor of 2.2. The skin factor decreased from -3.6 after the first injection period to -5.3 after the 12th injection period. These skin factors corresponded to an increase in the apparent fracture half-length from 6 to 31 m.

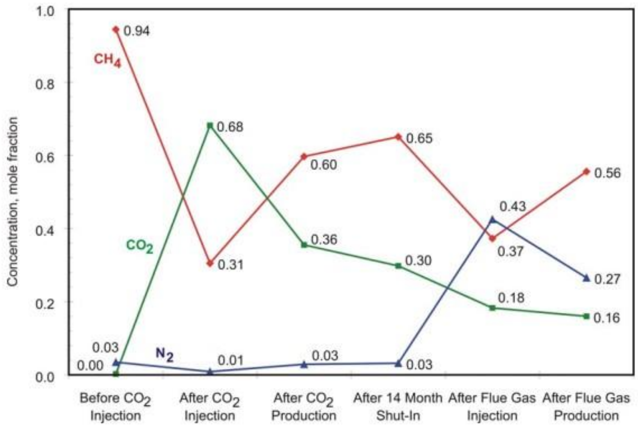


Figure3.40 Free Gas Composition

As will be discussed later, we believe that the permeability reduction during the falloff periods was due to swelling of the coal caused by sorption of CO_2. However, the permeability probably increased during injection. The increase in the effective induced fracture length may have been due to creation of new fractures or due to opening pre-existing fractures induced by the original stimulation as reported previously. Following the final injection, we allowed the CO_2 to soak in the coal for 39 days. The long soak time reduced transient effects caused by CO_2 sorption and methane expulsion.

3.3.2 Indirect Fracturing Technology

3.3.2.1 Technical Principle

In the case of poor coal seam fracturing, we can change the exhaust passage. In many cases a lower stress sandstone or siltstone adjacent to a coal or between two coals can be a much more efficient means of propagating efficiently out away from the wellbore yet intersecting and accessing gas production from adjacent coal seams, so as to achieve the purpose of improving the recovery of coalbed methane. This is a technique that was first perfected and very successful in the North Sea, it is called Indirect Vertical Fracture Connectivity or IVFC. The basic method is that the coal seam and its surrounding rock are fractured at the same time. Due to the strong fracturing of the surrounding rock, the fractures in the surrounding rock after fracturing extend both farther and deeper in the horizontal and vertical directions. Except for the gas around the wellbore can enter the wellbore through the fractured coal seam, the coalbed methane away from the wellbore is mainly discharged to the surrounding rock through the contact surface between the coal seam and the surrounding rock. Then the gas flow along the fissure channel of surrounding rock to the well to be drained.

3.3.2.2 Features

A. The vertical permeability of coal is most often better than the horizontal permeability, so an indirect fracture need not completely penetrate the coal to effectively drain it. In addition, the leak off caused by the permeability in the coals will draw the proppant into the intersection and assure a highly conductive pathway.

B. The lower fracturing gradient of the sandstone or siltstone, growing to a coal seam, will ensure an elastically coupled intersection into the coal seam with connectivity all along its length.

3.3.2.3 Technical advantages and disadvantages

(1) After fracturing, the surrounding rock can produce a large number of fissures and fractures of various sizes that extend farther and farther, and the pressure drop generated by drainage at the well bore can be transmitted farther by these fissures and cracks. Not only the CBM around the wellbore reaches the drainage extraction, but also the gas farther away from the wellbore will also reach the extraction.

(2) It can reduce the permeability of the vulnerable coal damage.

(3) It can avoid the high plasticity and low permeability of coal seam coalbed methane mining adverse effects. The gas in the coal seam enters the surrounding rock fracture channel from the contact surface of the surrounding rock much less than the distance from the coal seam to the wellbore. Therefore, the migration resistance during coalbed methane extraction must be much

smaller.

3.3.2.4 Case Study

(1) Case in US

A. Case in Utah

This is a case in Utah. Figure. 3.41 shows the 1-year normalized production for 31 wells that were perforated in the coals only and for 42 wells in which perforation modifications were made including perforating into the adjacent sands as well as the coals. Production rates across the frequency distribution curve for the wells perforated in the sand were consistently double that of the wells that were perforated coal only. In addition, the average treating pressures of the sand perforated wells were reduced by almost 1,000 psi and screen outs were significantly reduced.

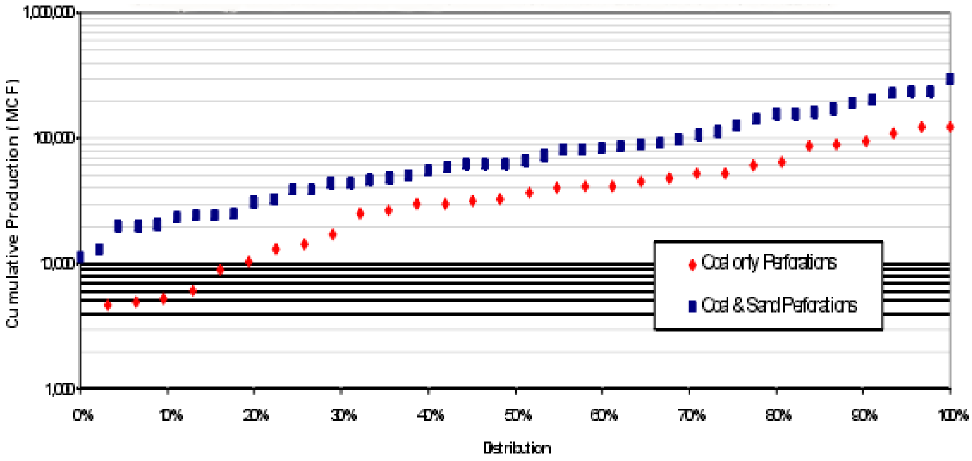


Figure. 3.41 Uinta Basin, Ferron Formation Frequency Distribution for One Year Normalized Cumulative Production

Source: T.N. Olsen,2003

B. Case in Central Rockies

This case is in the Central Rockies. During a 15 well CBNG study, 11 wells were perforated in the coals only, then 4 wells were perforated in the adjacent layers as well as the coals. In the 11 wells that were perforated in the coals alone, the screen out rate was 65% (7 of 11). When the perforations were modified to include adjacent layers, the screen out rate went to zero. Figure.3.42 shows the average production rates for 11 coal-only wells vs the 4 coal-plus-sand perforated wells. The production rates in the latter were double the rates of the coal only wells.

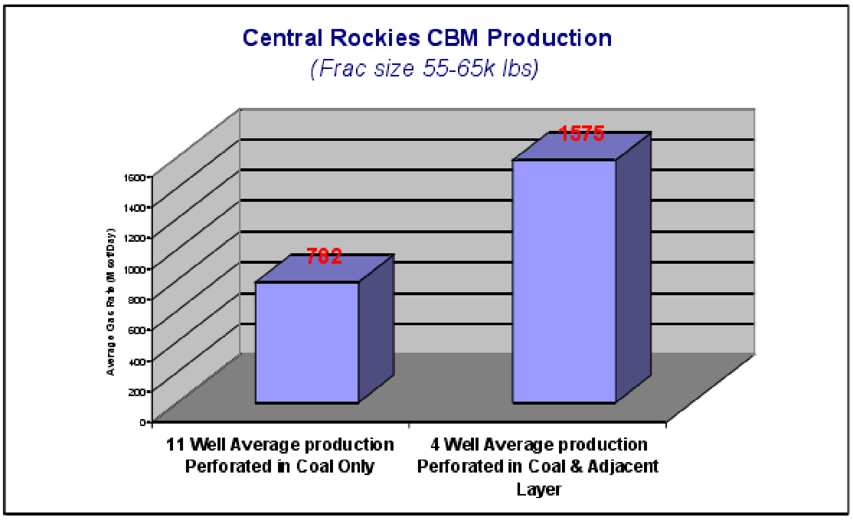


Figure.3.42 Production Comparison Initiating Fracturing's in Coal vs. Adjacent lower Stress

Source: T.N. Olsen,2003

C. Case in San Juan Basin

This case is a San Juan basin two-well side-by-side fracturing comparison. One well was perforated in the coals only, and the other well was perforated in the coals and in the sand interface. Figure.3.43 shows the cumulative production comparison of the two wells.

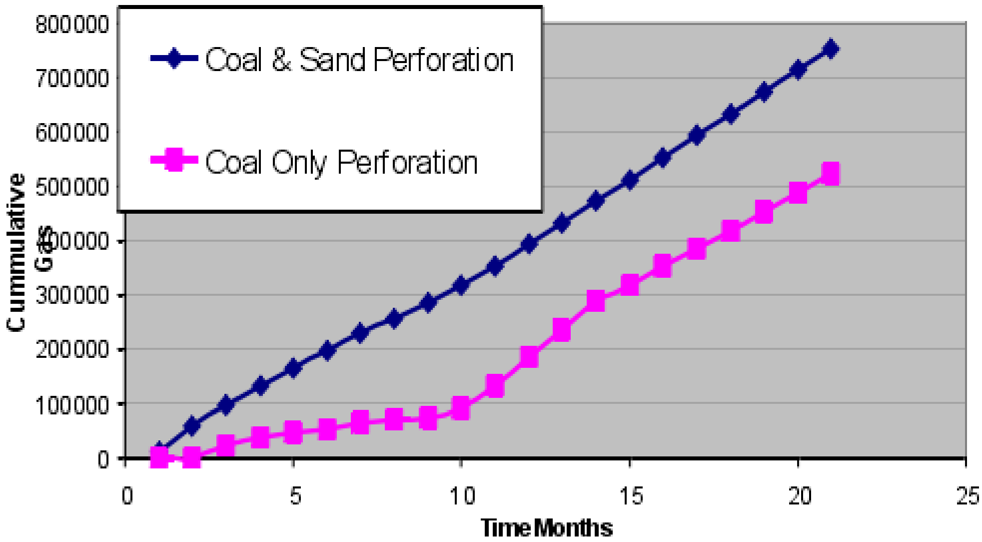


Figure. 3.43 Fruitland coal two well comparison

Source: T.N. Olsen,2003

D. Case in Cameo A Coal Seam

In this example there are four offsetting wells, two wells were perforated directly into the

Cameo A coal seam only, and two wells had a modified perforating design that included only the top half of the coal seam with the perforations extending into the overlying clastic rock.

Well A: Figure 3.44 shows the lithology of the well A and demonstrates the typical Cameo A sequence. The Cameo A is 25 to 40 feet thick coal that sits on top of the thick marine Rollins formation which in this area is nonproductive. In the Well A completion, the entire coal seam was perforated and the Cameo A was stimulated with over 200k of 20/40 sand proppant using linked gel fracturing fluid. The fracture gradient was .82 psi/ft and the net fracturing pressure gain after this treatment was only 150 psi. With this very low fracture pressure gain, it is very unlikely that the fracture treatment stayed contained within the 30' coal seam, and very likely grew downwards into the water wet Rollins marine sand.

Well B: The second well was also perforated directly into a 25' coal seam but because of the height growth experience with well A, it was decided to use a slick water fracturing as a fracturing fluid, and just over 100k of 20/40 proppant was placed in this treatment. In this case the net pressure build was dramatically different. In this treatment the starting fracturing gradient was .8 psi/ft, but the net pressure was nearly 2500 psi at the end of the treatment. This very high net pressure in this fracture treatment indicated that containment in the coal seam was likely, but the high net fracturing pressure also exceeded the overburden stress by a significant margin. This from our experience would indicate that inefficient complex fracturing would be very likely.

Well C&D: The next two wells enabled an optimized perforation strategy that perforated not only the coal but also the target clastic layer of rock. In well C 170K sand was placed using linked gel to ensure there was enough net pressure for the fracturing to connect to both the upper and lower coal seams, the final net pressure of 800 psi was right in line for a contained 60' high fracture that connected to both coals. Well C was a thick basal coal with sand layer above and the Rollins marine sand below. Perforations were designed to penetrate the top half of the coal seam and 20’ into the overlying sand. The stimulation treatment was conducted with a thin slick water fluid to reduce upward growth, 135K of 20/40 proppant was pumped with a final net fracturing pressure of 600 psi. Figure 3.45shows the cumulative production results of these four wells after more than three years of production. The two direct coal fracture wells have produced less than 35 million scf gas while the two IVFC completions have produced in excess of 250 million scf each. Four wells would hardly be a statistically valid sample to draw mass conclusions from, but a nearly 8-fold difference in production is compelling.

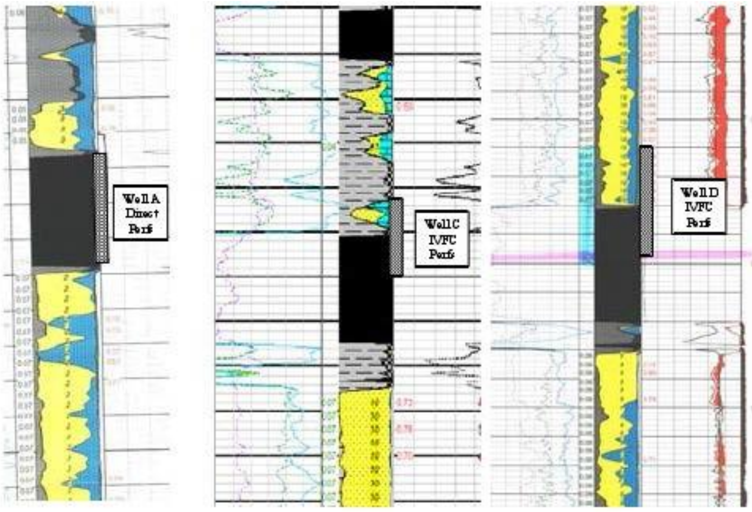


Figure 3.44 Well A, C & D, Piceance Basin Cameo A Coal Lithology with the Marine Rollins sand immediately below

Source: T.N. Olsen,2007

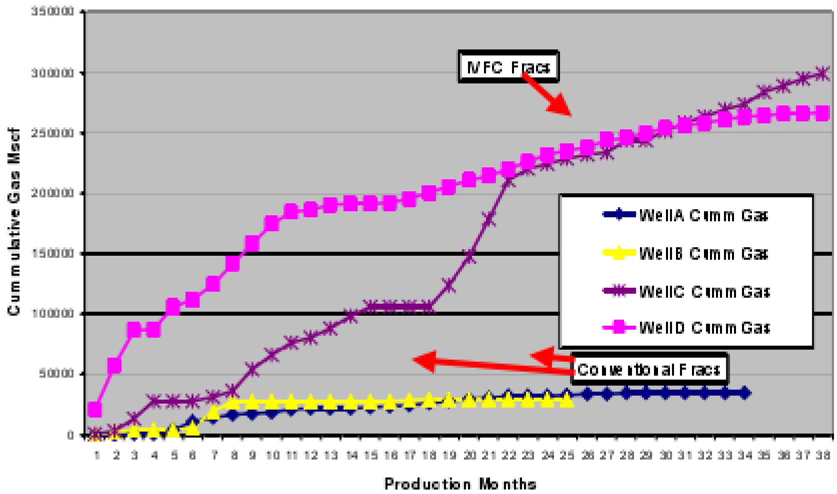


Figure 3.45 Well A, B, C, & D Production Comparison

Source: T.N. Olsen,2007

F. Case in North Piceance

Figure 3.46 shows the log of an operator in North Piceance the perforations market with the number 1 were the first perforations shot in the well, these were directly into the coal seams. The well was stimulated from these perforations and the production after the fracturing was 200 Mcf/day. Post fracturing analysis indicated that the fractures might have grown into the sands adjacent to the coal seams, so it was decided to re-perforate into these sand layers adjacent to the coal. These are the perforations marked with the number 6. The water and the gas production after the re-perforations increased substantially, the production log evaluation (on the right of the figure) indicated that gas production had jumped to 1200 mcf/day with the majority of the production coming from the sands located between the coal seams. This gives us a strong indication that the perforations in the sand layers had better connectivity to both the sands and the coals than the original perforations. After this finding the operator began to use the sand layers to initiate fractures and allow these induced fractures to grow and connect with the adjacent coal layers, then both the sands and the coals were produced concurrently.

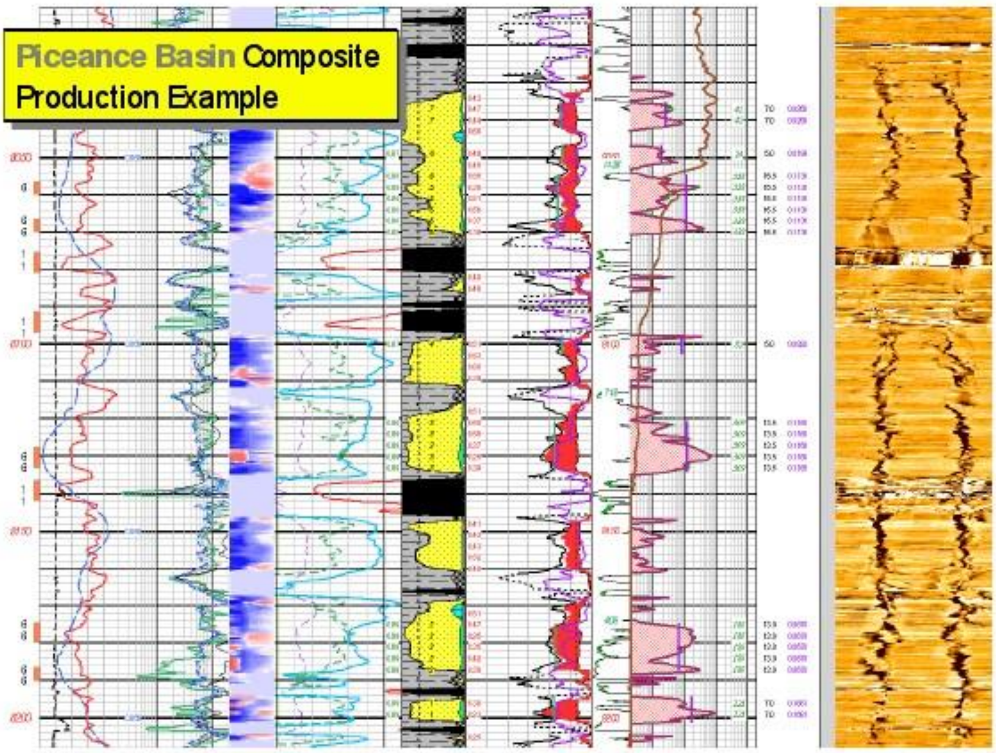


Figure 3.46 Deep Piceance Productivity Example

Source: T.N. Olsen,2007

(2) Case in Canada

The case (Reynolds, et al. 2005) of hydraulic fractures in a wet, tectonically stressed coal in the Alberta foothills area. Figure 3.47 shows the radioactive tracer log from a well completed with the IVFC technique between two coal seams. The fracture screened out early due to a surface equipment problem. The log shows some height growth into the upper and lower coals, with what appears to be some shear or complex fracturing near the base of the upper coal. The fracture has not grown vertically past the mid-point of the thicker upper coal.

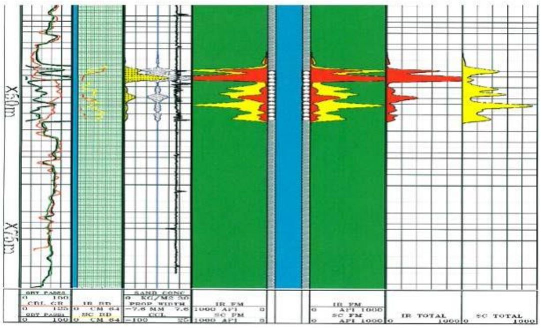


Figure 3.47 Radioactive Tracer Log Following a Premature Screen out

The well was refractured, and all proppant was placed as planned. The refracture was also radioactively traced, and the log is shown in Figure 3.48 The log shows the fracture grew vertically to fill all of the upper coal, and most of the lower coal. Some inferred fracture complexities may be seen as 'hotter' areas, where more radioactive material was placed. These are probable shear, horizontal component fractures near the top of the lower coal, and near the bottom of the upper coal.

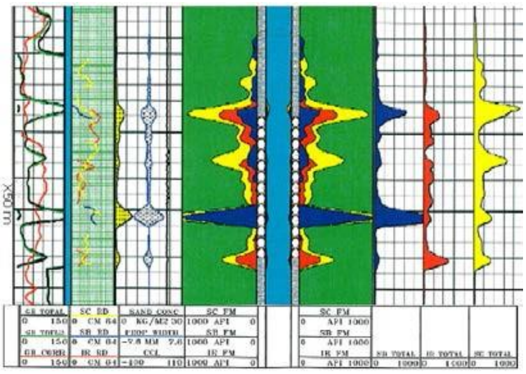


Figure 3.48 Radioactive Tracer Log After Refracture

The conclusion from this analysis is the IVFC technique was successful at placing the fracture into the two coal seams in a single stage, while reducing fracture complexities. Following the refracture treatment, the well responded with approximately a 3-fold increase in the water production rate indicating that significantly more coal had been effectively stimulated.

(3) Case in Australia

Figure 3.49 shows a stress profile of coal seams along the western flank of the Green River Basin, and this area is very near the over thrust belt and is under tectonic compression. In this stress profile the coal seams are significantly lower than the adjacent sands and siltstones. In this case indirect fracturing would be more problematic. In fact, in tectonically compressive environments, the prospects for efficient deep penetrating induced fracture stimulation are greatly reduced.

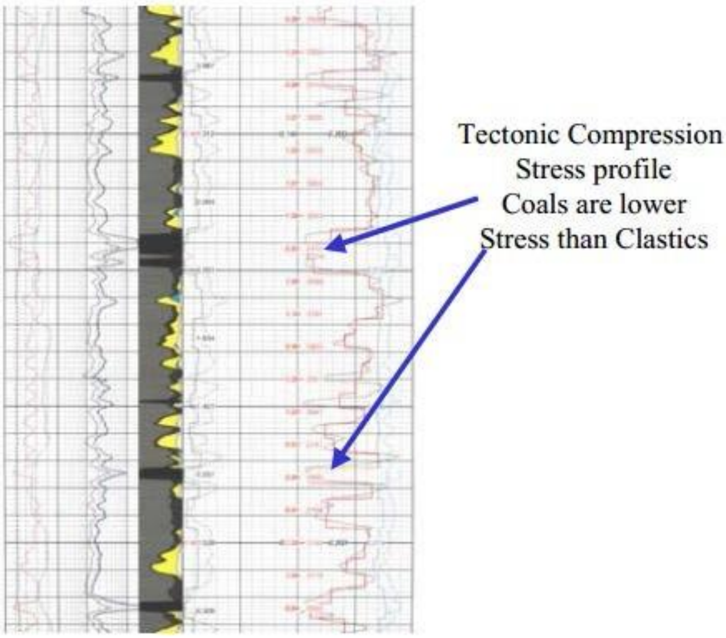


Figure 3.49 Tectonic Compression Stress profile

Source: Application of Indirect Fracturing for Efficient Stimulation of Coalbed Methane Example in Australia:(Ymond L. Johnson,2002)

4. Assessment tools of CBM Development

4.1 Applicable conditions

By analyzing the technical characteristics, advantages and disadvantages, and successful cases of different CBM well types, drilling techniques and fracturing stimulation technologies, the applicable conditions for different well types and fracturing stimulation technologies are concluded.

4.1.1 Well types

4.1.1.1 Vertical Well

Vertical wells were utilized due to the relatively shallow depths and the total thickness of the formation. However, companies found that drilling several wells in an area provided economies of scale in all facets of the development scheme. Additional gas flow improvement is not compulsory as the assembly of the vertical and fracture wells are constant at these shallow depths because of high permeability and low pressure.

The openhole cavity completion technology for vertical well

While this technique has increased the initial methane production in some wells by as much as 4 to 5-fold when compared to wells which were hydraulically fractured, it has also been shown that this cavity induced stimulation technique has not worked in other wells. Studies indicated that this failure may be due to the cleat density being much less than it was in the successful completed wells. More likely, the failures were due to the large hoop stresses induced in the coal during the drilling process. The lower cleat density increases the strength of the coal sufficiently that these hoop stresses cannot be overcome with the normal cavitation completion techniques. (Montgomery C T. 1992)

Seam characteristics that will lead to success using cavitation methods are coals at least 10 ft thick, have permeability greater than 20 m D, low density (low ash), at or above water gradient pressure, and preferably in a high in situ stress regime. The extent of the fracturing of the coal will extend beyond the physical enlargement of the hole as stress is relieved. Rogers et al. provide more detail into the San Juan cavity completions in Chapter 7 of Coalbed Methane: Principles and Practices (Rodgers, 2007).

Vertical wells were utilized due to the relatively shallow depths and the total thickness of the formation. However, companies found that drilling several wells in an area provided economies of scale in all facets of the development scheme.

Table 4.1 CBM engineering practices cutoff values for vertical well completion

Engineering Practice	Key Geologic Parameters	Cutoff - Values
Top set Under Ream	Depth of Coal Seam	< 1800ft
	Coal Seam Thickness	> 30ft
	Permeability	> 100mD
Open Hole Cavity	Compressive Strength of Coal	< 1000psi
	Permeability	> 10mD
	Rank of Coal	HV - LV
Cased Hole Completion with Hydraulic Fracture Stimulation	Permeability	<100mD
	Depth of Coal Seam	< 6000ft
	Rank of Coal	HV - LV
Cased Hole Completion with Hydraulic Fracture Stimulation (Multi-Stage)	No of Coal Seams	> 2
	Vertical Separation	> 40ft

4.1.1.2 Horizontal Well

Depth also impacts greatly on the stability of a horizontal wellbore during drilling and production. At deep layers, drilling methods are applied for better precision and flexibility. Enhanced gas recovery approaches like extra hydraulic fracturing may be used to enhance the release of methane from coal layers in these horizontal systems. Especially, only one or two, thick, high gas content but low permeability (<2mD) coal seams are present, horizontal drilling usually be considered and, often, is the only option available to produce the gas at economic rates.

Horizontal wells have been reported to produce gas rates up to 10 times more than vertical wells drilled in the same coal seams, with the average being 4–5 times (Matthews, 2005). In spite of this great advantage, horizontal wells are 2–3 times more expensive to drill or more, depending on depth. Depth also impacts greatly on the stability of a horizontal wellbore during drilling and production. In situations where there are numerous, thinner coal seams present having reasonable permeability (>5–10mD), vertical drilling and completions is the preferred option. However, when only one or two, thick, high gas content but low permeability (<2mD) coal seams are present, horizontal drilling should be considered and, often, is the only option available to produce the gas at economic rates.

Table 4.2 CBM engineering practices cutoff values for Horizontal Well

Engineering Practice	Key Geologic Parameters	Cutoff - Values
Horizontal Well	Thickness of Coal Seam	3 - 20 ft
	Extent of Coal	> 1500 ft
	Dip of Coal	< 15 deg
	Depth of Coal Seam	500 - 4000 ft

4.1.1.3 Multi-branch Horizontal Well

The multi-branch horizontal well is favorable for high-order CBM reservoir with thick seam, high gas content, low permeability and high strength. It is suitable to be deployed to sections with little change of underground reservoir, rare fault and complex ground conditions. Specific application conditions are as follows: a)coal seam structure is stable without large fault, far from water layer and with favorable sealing conditions;b)minge and tectonic coal is not developed;c)coal seam burial depth is less than 1000m;d)single layer thickness is larger than 4m;e)gas content is high, generally larger than15m^3/t;f)main branch is in parallel with coal seam or up dipping;g)effective footage of coal seam is larger than 3000m;h)main well and branches of multi-branch horizontal well are arranged reasonably: main well is about 1000m long, and branch gap is 150-200m, included angle is 10-20°;i)Usually during CBM development process, the multi-branch horizontal well is the major technology, and vertical wells are arranged around the horizontal well to help drain water and reduce pressure. The development mode of multi-branch horizontal well + vertical well is formed, such as in

Qinshui Basin, China.

The multi-branch horizontal wells in pinnate pattern have been drilled in Arkoma and Appalachian basins. In addition to the conditions that are needed for drilling horizontal wells, multi-branch horizontal wells have been drilled in low-permeability coals (< 1mD). Other geologic conditions to consider when selecting pinnate wells are 79 coal that is free of intrusions and other geological structures, such as folds and faults. We conclude that, if the conditions for horizontal wells are satisfied and the permeability of the coal is less than 1mD, then drilling multi-branch horizontal wells is the best option.

For cases where coal depth exceeds 4000 ft or is less than 500 ft, areal extent of coal is less than 1500 ft, and/or coalbed dip is greater than 15 degrees, we check whether coal depth exceeds 6000 ft, and if so, we conclude that CBM production is not economical, based on experience to date. For all the other remaining conditions, cased-hole completions with hydraulic fracturing are the best completion and stimulation method.

The technology requires accurate pressure management during the drilling operations to minimize formation damage, while mitigating borehole stability problems. Over-balanced drilling reduces potential problems with borehole stability and resulting stuck down-hole tools but can lead to significant formation damage. Under-balanced drilling minimizes the potential for formation damage but requires close attention to the safe handling of the produced gas. Pressure management is carried out by controlling the amount of air injected into the drilling fluid during drilling operation. CDX uses a Dual Well system (Figure 3.15: Dual Well System with Air Injection) to reduce the weight of the fluid column. The air is injected into the drilling fluid at the cavity elevation of the vertical well. This allows for maximum control over the pressure environment in the horizontal well bore.(Schoenfeldt H V, Zupanik J. 2004)

Table 4.3 CBM engineering practices cutoff values for Multilateral/Pinnate Wells

Engineering Practice	Key Geologic Parameters	Cutoff - Values
Multilateral/Pinnate Wells	Permeability	<1 mD
	Thickness of Coal Seam	3 - 20 ft
	Extent of Coal	> 1500 ft
	Dip of Coal	< 15 deg
	Depth of Coal Seam	500 - 4000 ft

4.1.2 Fracturing Technology of Coalbed Methane Well

4.1.2.1 Direct Fracturing Technology

Applicable geological conditions of water-based fluid fracturing technology compared with the special fracturing technologies (N_2 fracturing technology, CO_2 fracturing technology, etc.).The following points are highlighted:

(1) The depth of the reservoir.

The general situation is applicable to the shallow coal reservoir of 2000 meters, because as the reservoir depth increases, the friction resistance increases gradually. The ground pumping pressure increase is not conducive to safe fracturing treatment.

(2) The reservoir property.

The coal reservoir contains a lot of minerals, there are the interactions between minerals and water-based fracturing fluid, the possible phenomenon is the water sensitivity, makes the treatment of the reservoir fail, so the treatment must ensure the fracturing fluid system's compatibility with reservoir property conditions.

(3)• The coal body structure.

The structure of the coal has been damaged in the broken soft coal seam, and the hydraulic fracturing will damage the reservoir, which is not conducive to the propagation of the hydraulic fracture's length in the reservoir.

4.1.2.2 Coiled Tubing Fracturing Technology

The formation is revealed that most of the gas pool comprises of marine siltstones and mudstones with no sandstone being present. Siltstone lenses are generally less than 1 cm thick,some of these lenses may be interconnected vertically giving some degree of horizontal continuity. Siltstones and mudstones are typical of some of the other formations in the Lower and Upper Cretaceous and these may exhibit similar properties to the Milk River.The geology of the Milk River formation (and probably others in southeastern Alberta) results in a multitude of very thin producing lenses. The target zones for fracturing are thus well suited to coiled tubing fracturing.

4.1.2.3 N_2 Fracturing Technology

In late 2000, Canada began testing our first Horseshoe Canyon coal seams with a standard water injection falloff test, a common practice in the industry.Results from these initial tests were very discouraging because it was very difficult to inject water into the coals. Normally,this indicates an extremely low permeability. To restore some communication with the reservoir, we then tried a technique that had been used previously in the Appalachian Basin: high rate, dry nitrogen injection.These nitrogen injection treatments resulted in methane production from the coals and led to the discovery that the Horseshoe Canyon coals are dry, and very sensitive to liquid exposure. Fortunately, the discovery that the Horseshoe Canyon coals are dry over a large geographic area meant that dewatering would be unnecessary, resulting in significant savings of capital and operating costs.

A typical Horseshoe Canyon CBM well is drilled with water or air, cased and cemented, and then perforated to open the coals to the wellbore. But, the unique nature of the Horseshoe Canyon coals precluded traditional stimulation practices. It had already established that injecting water into the coals was very damaging, which eliminated water-based fracturing fluids, and even high-quality foam systems. And, the low reservoir pressures in these coals meant that there may not be enough natural energy to flow back the fracturing fluid after stimulation. Without water or some other viscous fluid, we could not transport proppant into the coal seams to stimulate the wells. Finally, it was difficult to effectively stimulate (conventionally) the large number of open coal intervals in a typical Horseshoe Canyon well (Bastian et. al 2005).

4.1.2.4 CO_2 Fracturing Technology

At reservoir conditions, CO_2 adsorption exceeded CH_4 adsorption by a factor of five, suggesting that CO_2 enhanced gas recovery from coal could serve as a promising mean to reduce life cycle CO_2 emission for CBM. On a strictly volumetric basis, gas coal has the potential to sequester large amounts of CO_2, provided that CO_2 can diffuse deep into the matrix. When taken into fracturing, it can cause much more complicated fractures for its lower viscosity property, which has a benefit to CBM exploitation. The energy provided by CO_2 results in the elimination of all residual liquid left in the formation from the fracturing fluid. The gaseous CO_2 also aids in lifting formation fluids that are produced back during the clean-up operation. Where by the adsorbed methane gas is displaced by the competitive adsorption of CO_2, due to its higher adsorption affinity for coal and capacity. CO_2 is usually preferred for deep applications rather than N_2 due to CO_2's higher specific gravity, lower friction pressure (than N_2 foamed fluids) and leak off control properties.

The Horseshoe Canyon coals contain many named seams such as Lethbridge, Dorothy, Nevis, Drumheller and Ardley. This family of coals is characterized by their pervasiveness throughout central and southern Alberta, multiple coal sequences in each well bore and possibly the most important is their apparent “dryness”. These coals produce little to no water which results in very quick on-stream time and low operating cost. This apparent low water saturation and potential desiccated condition of the coal is the principle reason for the application of non-aqueous fracturing systems in these coal seams.

4.2 Assessment tools

4.2.1 Reservoir geological conditions corresponding to different technologies

(1) Coal reservoir parameters suitable for dynamic cavity completion

Rank of coal : High volatile bituminous coal and higher rank coal seam；

Depth of coal seam: 600-1000m；

Thickness of coal seam: more than 6m；

Permeability: greater than 5mD；

Gas content of coal seam: >8 m^3/t；

Ash content of coal: <70% (The lower the ash content, the better the crack extension effect during the completion of the cavity, and the higher the permeability)；

Reservoir pressure: overpressure (the higher the reservoir pressure, the more CBM will be adsorbed)；

Capping conditions: good seal ability, high mechanical strength, no faults on the roof and floor, without water-bearing thief zone;

Typical Basin: San Juan Basin.

(2) Coal reservoir parameters suitable for well completion of cased hole expansion

Rank of coal : medium and low coal rank;

Depth of coal seam: over 600m;

Thickness of coal seam: 15-30m;

Permeability: greater than 20mD;

Gas content of coal seam: 2-8m^3/t；

Ash content of coal: <70%;

Reservoir pressure: normal pressure or near at mospheric pressure;

Typical Basin: Surat Basin, Powder River Basin.

(3) Coal reservoir parameters suitable for vertical well fracturing completion and multi-layer coal mining

Depth of coal seam: 300-1000m;

Numbers of layers of coal seam: no less than 3 layers;

Thickness of coal seam: more than 1m for single layer, total thickness: 10-50m is suitable;

Permeability: 10-15mD;

Gas content of coal seam: greater than $11m^3/t$;

Reservoir pressure: slightly under pressure or normal pressure;

Typical Basin: Raton Basin, Uintah Basin.

(4) Coal reservoir parameters suitable for multi-branching horizontal wells and horizontal wells for staged fracturing and completion

Depth of coal seam: 800-2000m;

Numbers of layers of coal seam: usually1-2 layers;

Thickness of coal seam: net thickness: over 2-6m;

Permeability: 0.1-15mD;

Gas content of coal seam: $5\text{-}10m^3/t$, slightly unsaturated.

Typical Basin: Alberta Basin

4.2.2 Assessment Tools

By analyzing the coal reservoir parameters corresponding to different CBM well types, drilling techniques and fracturing stimulation technologies of the United States, Canada, Australia and China, the Reservoir Parameters Requirements for Different Well Completion Methods and Fracturing Stimulation Technologies are summarized (Table 4.4-4.5) and based on the results, the Application Conditions for Different Well Completion Methods and the Selection Basis and Tools for Fracturing Stimulation are established (Figure 4.1-4.3).

Table 4.4 Reservoir Parameters Requirements for Different Well Completion Methods

Engineering Practice	Key Geologic Parameters	Cutoff - Values
Topset Under Ream	Depth of Coal Seam	< 1800 ft
	Coal Seam Thickness	> 30 ft
	Permeability	> 100 mD
Open Hole Cavity	Compressive Strength of Coal	< 1000 psi
	Permeability	> 10 mD
	Rank of Coal	HV - LV
Horizontal Well	Thickness of Coal Seam	3 - 20 ft
	Extent of Coal	> 1500 ft
	Dip of Coal	< 15 deg
	Depth of Coal Seam	500 - 4000 ft
Cased Hole Completion with Hydraulic Fracture Stimulation	Depth of Coal Seam	< 6000 ft
	Rank of Coal	HV - LV
Cased Hole Completion with Hydraulic Fracture Stimulation (Multi-Stage)	No of Coal Seams	> 2
	Vertical Separation	> 40 ft
Fracturing Fluids		
Water without Proppant	Permeability	> 100 mD
Gas with/ without Proppant	Water Saturation	< 5%
Foam with Proppant	Water Saturation	< 50 %
	Reservoir Pressure Gradient	< 0.2 psi/ft
Water with Proppant	Permeability	< 10 mD
Cross Linked Gel with Proppant	Permeability	> 1 mD
	Distance to Strong Barrier	> 20 ft
	Distance to Aquifer	> 30 ft

Table 4.5 Match Table of CBM Fracturing Technology and Geological Condition

Multiple coal seam	Separate Layer fracturing	Sand filling layer	The same with Single coal seam fracturing	
		hydraulic jet perforation and fracturing	Oil jacket mixed injection	As the same as Single coal seam fracturing
			tubing fracturing	Small displacement low sand ratio deblocking fracturing
		sliding sleeve ball injection and other layering tool separate fracturing	Different tools; The fracturing construction parameters are the same as single coal seam fracturing	
Single coal seam	Thick coal seam (>8m)	The structure of coal seam is more stable	Intra- layer fracturing	Fracturing technology optimization is the same as single coal seam fracturing
		Loose structure of coal seam	Large-scale fracturing of upper coal seam	
	Thin coal seam	Without water in roof and floor plate, good permeability, content of swelling clay mineral is low	Indirect fracturing	
		Water in Roof and floor	Fracture height fracturing	Floating/Sinking temporary plugging agent fracturing
				Short-distance focused perforation, Low displacement low sand ratio fracturing
				Water blocking agent fracturing
		Without water in roof and floor plate, but with poor permeability, or swelling when there is water	Water-bearing coal seam	Reactive water hydraulic fracturing
			coal seam without water	Nitrogen/CO_2 foam fracturing
				Liquid nitrogen/CO_2 dry fracturing

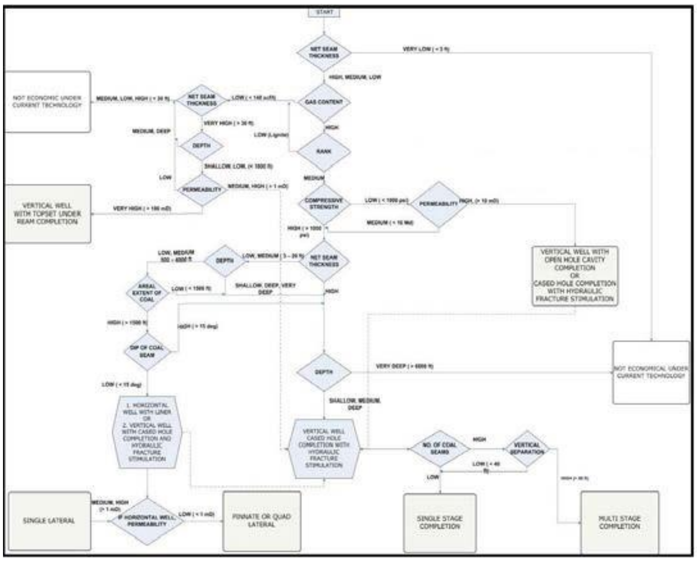


Figure 4.1 Selection Tool for well type, completion, and fracturing stimulation options

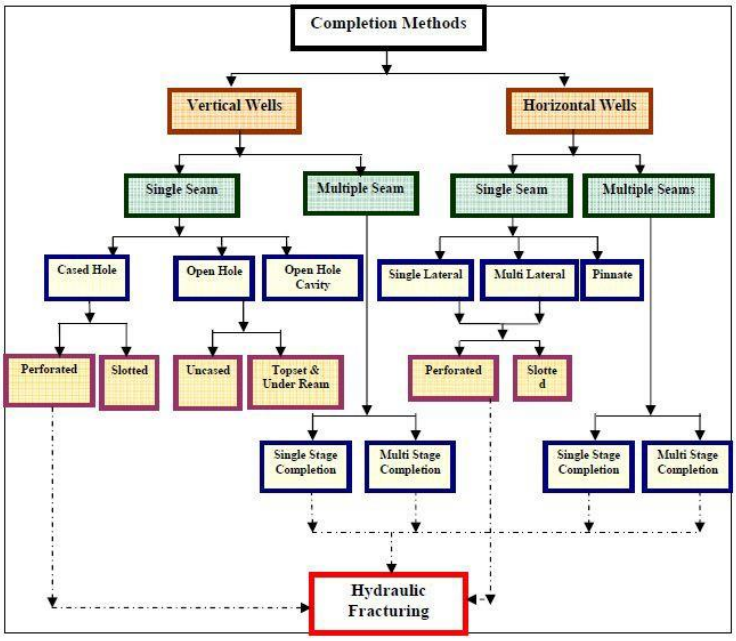


Figure 4.2 Selection basis for completion methods of CBM vertical well and horizontal well

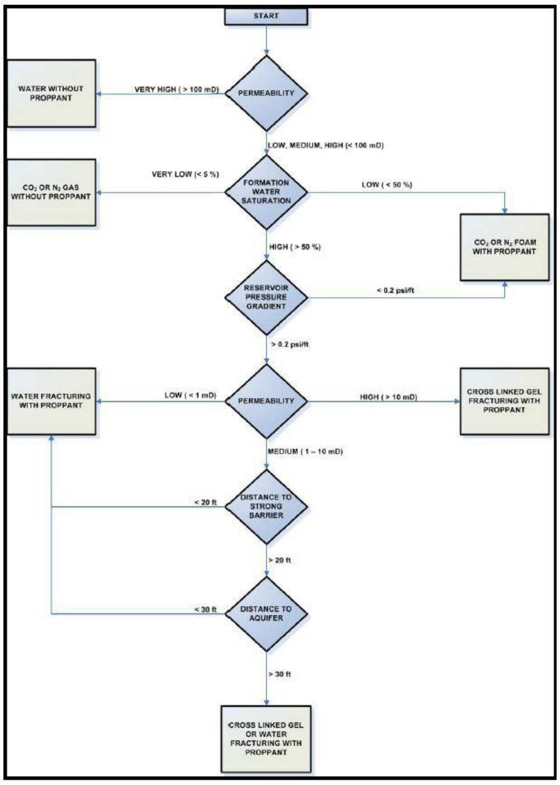


Figure 4.3 Selection basis for vertical well fracturing and completion methods for reservoirs with different permeability

4.3 Case Study

This project takes the development of coalbed methane resources in Indonesia South Sumatra Sekayu as the case for analysis.

4.3.1 Coalbed methane reservoir geological conditions in South Sumatra

South Sumatra was situated in the tropics with a landform of fan delta plain during depositional stage. Coal rank is relatively low in South Sumatra, and is primarily lignite to sub-bituminous grade. The coal seam is thick and is low-rank coal that is close to the base, suitable for the exploitation of coalbed methane. The Muara Enim group is about 500-700m thick, with the coal seam accounting for about 15% of its total thickness. Affected by the subsidence rate, coal seam in thinner stratum is also relatively thin. Rank data most commonly cited in the literature was obtained from surface outcrops and shallow mines, where the vitrinite reflectance (Ro,max) is only about 0.3%. However, coal rank increases gradually with depth in South Sumatra, which is a back-arc tectonic setting with high heat flow.

Gas content has not yet been measured in South Sumatrausing standard direct desorption methods from core. However, many petroleum wells in this basin experienced gas kicks while drilling through deep coal seams.

Reservoir pressure gradients were estimated from 30 well tests conducted in conventional formations the South Sumatra basin. The pressure/depth gradient averages at or slightly above hydrostatic levels, approximately 0.45 psi/foot. Deeper horizons below 1,500 m can reach gradients of over 0.5psi/foot. Temperature is somewhat elevated due to the high geothermal gradient in this back-arc tectonic setting. We estimate typical reservoir temperature of 68°C at target depth(600 m). Coal seam permeability and stress have not yet been tested in-situ. South Sumatra Sekayu SPC CBM reserves parameters are shown in table 4.6.

Table 4.6 List of CBM reserves parameters of South Sumatra Sekayu SPC

Reservoir Property	Indonesia South Sumatra Sekayu SPC	
	Variable	Source
Depth（ft）	2000	Well Logs
Coal Thickness (ft)	147	Well Logs
Coal Rank (Ro,max)	0.3%	Lab Test
Gas Content（ft^3/ton）	>100	Corelab
Gas Saturation	95%	Weatherford
Permeability(mD)	500	Medco
Source: BBC= Bill Barrett Resources 2011. USGS= US geological Survey 2004		

4.3.2 Development Technology Solutions

According to analysis of South Sumatra geological conditions, its geological conditions are similar to those of the Powder River Basin in the United States, after compared with the United States, Canada, Australia, and China regarding burial depth, coal thickness, coal rank and other geological conditions. The specific parameters are shown in Table 4.7.

Table 4.7 The contrast of CBM reserves parameters between South Sumatra Sekayu SPC and Wyoming USA Powder River Big George Coal

Reservoir Property	Indonesia South Sumatra Sekayu SPC			e Coal
	Variable	Source	Variable	Source
Depth（ft）	2000	Well Logs	1200	BBC
Coal Thickness (ft)	147	Well Logs	120	BBC
Coal Rank (Ro,max)	0.3%	Lab Test	0.3%	USGS
Gas Content（ft^3/ton）	>100	Corelab	50	USGS
Gas Saturation	95%	Weatherford	60%	USGS
Permeability(mD)	500	Medco	500	USGS
Source: BBC= Bill Barrett Resources 2011. USGS= US geological Survey 2004				

The analysis results show that the coal thickness, coal permeability, gas content and gas saturation in South Sumatra are superior to those in the Powder River Basin in the United States. With assessment tool of this project and mature development technology of the Powder River Basin, it is recommended to use vertical wells with open hole cavity completion technology to develop coalbed methane resources, while encouraging active exploration of technologies such as multi-branch horizontal wells, reducing investment costs, improving production and increasing development income.

5. Conclusion and Suggestion

5.1 Conclusion

(1) The APEC Economies have great potential of CBM development. CBM resources buried in 2000m underground for global onshore coalfields are about 256.1 trillion m^3, of which six economies including Australia; Canada; Indonesia; Russia; People's Republic of China and the United States have 244 trillion m^3, accounting for 95% of the total CBM resources in the world, having great potential development.

(2) The well drilling and completion technologies for vertical well and horizontal well for CBM development in APEC Economies have become matured. These technologies have been widely used in the Australia; Canada; China; and United States, achieved good results in output and economic benefits, formed matured technology system and accumulated successful experience, and provided important reference for the optimization of well types well drilling and completion and fracturing technologies selection in the CBM development in developing economies.

(3) APEC CBM development fracturing technology is mainly based on active water hydraulic fracturing, and important breakthroughs in N_2 and CO_2 and indirect fracturing technologies have been made in some basins, which provides technical guarantee for the CBM development in low-permeability basin and weak coal bed basin for APEC Economies.

5.2 Suggestion

(1) Indonesia and other APEC Developing Economies are still in the initial stage of CBM development, it is suggested that these Economies learn from the Australia; China and United States or their experienced in successful CBM industry development, and grant preferential policies such as financial subsidies and tax reduction and exemption in early stage to

encourage CBM development in their own Economies. The Economies should provide policy support for industrial development and reduce policy barriers.

(2) APEC developing economies should learn from other economies about well-types, drilling and fracturing technology optimization, advanced technologies, successful experiences and lessons from failure in CBM development process. They should apply the assessment tools established in the report by conducting analogy analysis of geological conditions, strengthening technical exchanges and other approaches to select the suitable well drilling, completion and fracturing technologies so as to decrease investment risk and blind investment to reduce risk costs and promote healthy and rapid CBM development in these economies.

(3) It is suggested that APEC Developing Economies open their CBM bidding market to attract international CBM development companies to enter into their development market through the modes of production sharing contract or establishment of joint ventures, actively introduce foreign capital, talents, experience and advanced technologies to accelerate the CBM development.

(4) Since exploitation results of CBM are greatly influenced by geological conditions, and CBM resource deposit are great differences in different APEC economies, it is suggested that APEC Developing Economies establish CBM research institutions and R&D teams to work out development technology system that is suitable for geological conditions of CBM deposit in their own economies by fully learning successful experiences and advanced technologies of other economies.

(5) It is suggested that APEC Developing Economies adhere to the principles of “overall deployment, step-by-step implementation and progressive development” in the CBM

development process. Pilot test for development should be conducted first, and mass deployment can be carried out after the pilot test for development achieves results.

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