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UNCONVENTIONAL NATURAL GAS RESERVOIRS

YACIMIENTOS NO CONVENCIONALES DE GAS NATURAL

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Resumen

Este trabajo es una exploración de los diferentes tipos de yacimientos de gas no convencionales en el mundo: mantos de carbón, formaciones apretadas, gas de lutita, gas de hidratos; describiendo aspectos tales como definición, reservas, métodos de producción, problemas ambientales, y económicos asociados a estos. También se mencionan estudios premilitares acerca de estas fuentes energéticas en Colombia.

Palabras Clave: Yacimientos no convencionales de gas, Gas lutita, Mantos de carbón, Gas de hidratos, Formaciones apretadas.

Abstract

This work is an exploration about different unconventional gas reservoirs worldwide: coal bed methane, tight gas, shale gas and gas hydrate; describing aspects such as definition, reserves, production methods, environmental issues and economics. The overview also mentioned preliminary studies about these sources in Colombia.

Keywords: Unconventional gas reservoirs, Shale gas, Coal bed methane, Gas hydrate, Tight gas.

1. INTRODUCTION

A definition of unconventional gas reservoir is not still precise. An economical definition for unconventional gas reservoir is, one that cannot be produced at economic flow rates without assistance from massive stimulations, treatments or special recovery processes. Other technical definition given by geologists and engineers refers to unconventional gas like, that one which is deposited in a continuous accumulation, such as shale or coal bed rock itself, rather than being gathered in a trap formed by faults (Mohaghegh, 2005). These accumulations in the basin are caused by the very low permeability of the reservoir rock where they are trapped. Unconventional gas doesn't refer to big chemical difference from the gas coming out of a conventional well, but instead is more of an allusion to the unconventional attributes of the reservoir itself and how that hydrocarbons are stored there. The name is actually most accurately used to describe the unconventional drilling and production methods that are needed to get the gas to the wellhead. The common theme is that these lower quality deposits, as far as permeability go, require improved technology and adequate gas prices before they can be developed and produced economically. The commercial production is immature and development of tight sand gas, coal bed methane, shale gas is undertaken mainly in the U.S and Canada up to date. In the past, technical challenges and cost issues around producing unconventional gas deterred resource exploration and development; however, as conventional gas resources are becoming depleted, and the need for energy has increased, the necessity for developing alternate resources has become important. According to the U.S. geological survey(U.S.GS) the unconventional gas resources account for a huge prospective reserve worldwide as shown in Table 1, thus unconventional gas reserves are becoming the new alternative to supply the global demand for an accessible, available and acceptable energy resource.

Unconventional natural gas resources have not received close attention from natural gas operators, this is due, in part, because geologic and engineering information on unconventional resources is scarce, and natural gas policies and market conditions have been unfavorable for development in many countries. In addition, there is a chronic shortage of expertise in the specific technologies needed to successfully develop these resources. As a result, only U.S. and Canada have had notable developments; however, during the last decade development of unconventional natural gas reservoirs has occurred in Australia, Mexico, Venezuela, Argentina, Indonesia, China, Russia, Egypt and Saudi Arabia (NPC, 2007). The main technologies developing to be feasible economical production of unconventional are been doing in US as mentioned before so special emphasis along this paper is going to be done on US. Futures studies necessarily will be done in South America and rest of the world as the demand of new resources increase and conventional reservoirs are mature. This article gives a brief review of unconventional gas reservoirs such as coal bed methane, gas hydrate, shale gas and tight gas

Table 1. Unconventional Gas Reservoir Reserves Worldwide in Tcf ([Steven, 2004)

Region	CBM	Shale Gas	Tight gas	Total
North America	3017	3840	1371	8228
Latin America	39	2116	1293	3448
Europe	275	548	431	1254
Formet soviet Union	3917	627	901	5485
ME and N, Africa	0	2547	823	3370
Sub Saharan Africa	39	274	784	1097
Centrally. Planned Asia and China	1215	3256	353	5094
Pacific	470	2312	705	3487
other Asia Pacific	0	313	549	862
South Asia	39	0	196	235
World	9061	16103	7406	32506

2. COAL BED METHANE (CBM)

Coalbed Methane is natural gas produced from coal seams where coal is both the source rock and reservoir. Each CBM basin is unique in terms of geology, topography, water saturation and water chemistry. During the earliest stage of coal formation, the sub-bituminous phase, biogenic methane is generated by bacterial action under defined conditions of low temperature (1220F), low depth and low pressure;

methane is stored within the coal in internal surfaces with subsequent release of water. Further burial and increased temperature (above 122^0F) generates thermogenic methane; in this phase coal reaches a rank of bituminous characterized by an increase of volatile matter and hydrocarbons in place. After excessive burial and about 300^0F the maximum generation of methane takes place, then the gas content of coal increases with depth, pressure and coal rank (Warlick, 2006). High pressures below the surface retain some methane in the coal matrix in an adsorbed state; this high pressure is created by both overburden and by the water that is contained in the coal matrix. Coalbed methane is made up of basically 90% or more methane as the name suggests; other gases that may exist in coalbed deposits in trace amounts are ethane, propane, butane, carbon dioxide and nitrogen. The heating value of this gas is usually less than 1000 Btu/scf, because the CO_2 content has no heating value.

The geologic characteristics of the coalbed methane reservoirs are complex because they correspond to naturally fractured layers with two systems of porosities (Collet, 2001) as shown in Figure 1. A primary porosity system is created by microporous with extremely low permeability making it impermeable to the adsorbed gas and non accessible to water, so desorbed gas only can flow through the system by diffusion. A secondary porosity system is defined by a set of natural fractures, cracks and fissures, well known as cleats or macroporous; they are the responsible of the permeability in the coal.

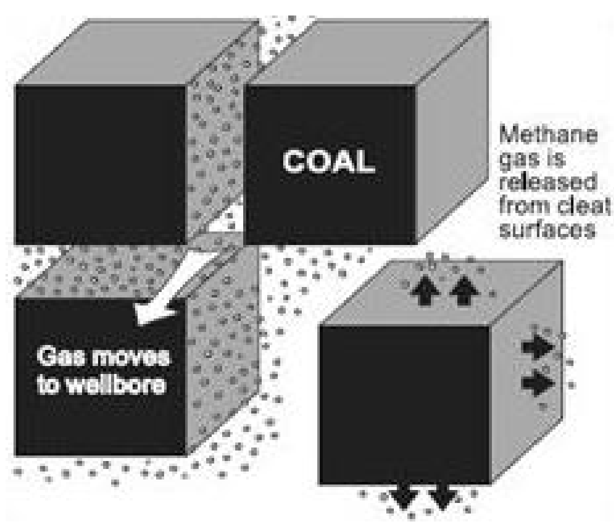

Figure 1. Coalbed Methane two porosity system. (Drahovzal, 2001)

Gas storage capacity or gas content of coal reservoirs is reported in units of scf/ton and is determined by measuring the volume of gas released from a coal sample while varying the pressure at isothermal conditions.

2.1. Reserves

As it is shown in Table No 1 coal bed methane reserves are spread out worldwide and mainly located in Russia, North America and Asia. It represents around 10% of the total unconventional gas resources worldwide. In Colombia Coalbed methane assessments show potential reserves in a range between 3 to 17 Tcf (Conpes, 2008). Major potential basins are mainly located in Bogota plateau, Guaduas formation, Guachinte-Ferreira formation, Cauca basin, Catatumbo basin, Llanos basin, Middle Magdalena basin and Cauca river basin (Conpes, 2008. Luna, 2004). Proof of potential for CBM is that along these carboniferous regions bituminous coal with up to 35% in volatile matter is present (UPME, 2005). Colombia has resources of coal; even tough, they have not been studied on deep Drummond company which produce carbon from Colombia has estimated 4.7 Tcf of proved reserves and 17 Tcf of potential Reserves (Drummond, 2009). Table 2 shows Colombian regions and potential and proved reserves in each state.

Table 2. CBM in Colombian regions (Zamora, 2009)

Colombian Coal Bed Methane				
Region	Carbon to produce TIP, 10^9 ton. M	Carbon, TIP 10^9 ton.m	GIP Tcf	Proved reserves(Tcf)
Guajira			4.8	2.4
Cesar	4.5	13.6	6.9	3.4
Córdoba	6.6	19.7	8.8	-
Antioquia	0.7	2.2	0.5	-
Valle del Cauca	0.5	1.4	0.3	-
Huila	0.2	0.7	0.0	-
Cundinamarca	0.0	0.0	1.6	0.8
Boyacá	1.5	4.4	1.8	0.9
Santander	1.7	5.2	0.5	-
N.Santander	0.5	1.4	0.8	-
Total	0.8	2.4	17.8	7.5
	17	51		

2.2. Production

In order to release the methane, producers drill holes to reach the coal layers, and large quantities of water must be pumped out to lower the pressure and help desorption of the gas from the rock, a typical curve of CBM production comprise three stages as showed on Figure 2.

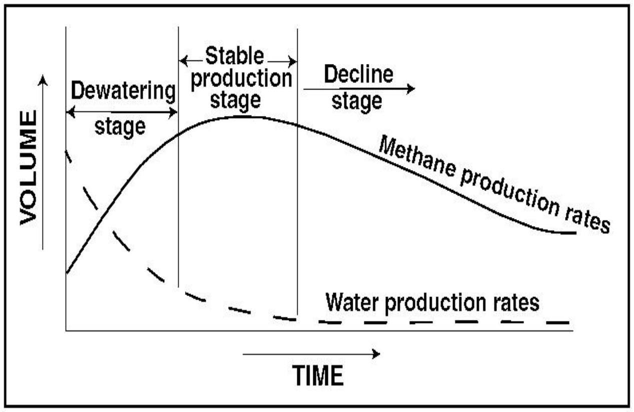

Figure 2. Typical production curves for a coalbed methane well. (Garbutt, 2004)

At the beginning mainly water come out from the wells (dewatering) in the second stage gas production increases and water in the coal is produced relatively permeable to gas increase. In the last stage both water and gas production decline (Garbutt, 2004).

If sufficient cracking and natural fractures occur in the formation, the methane will then flow to the well bore for production. Most CBM wells lie the 200-2000m range or less (Garcia, 2005). Presences of natural fractures are a major factor in determining productivity and commercial potential of the reservoir. If they are not present, additional hydraulic fracturing or other methods to create induced fractures must be applied to enhance the gas flow. Production technologies include conventional drilling and horizontal drilling. Horizontal drilling gives the advantage of covering larger areas which improve production and faster dewatering of the coal bed.

CBM production is attractive due to several geological factors. Coal stores six or seven times as much gas as a conventional natural gas reservoir of equal rock volume due to the large internal surface in the coal (Joshi, 2003). Much coal is accessible at shallow depths, making well drilling and completion relatively inexpensive. CBM has become a significant source of natural gas supply in the U.S. Nearly 10% of total U.S. natural gas production; cumulative reserves at the end of 2002 stood at 18.5 Tcf. Much of this reserve is low cost natural gas with all-in supply costs of under \$1/Mscf (Steven, 2004). Outside the US, CBM is undergoing initial commercial development in Australia and Canada, while exploration is underway in China, India, South Africa and several other coal-rich countries.

2.3. Environmental issues

Produced water treatment, safe disposal, the impact of extraction on the owners of surface lands and development of CBM resources on public lands that might also be reserved for other purposes are the major environmental concerns at the time the CBM well is produced, especially at the early stages when large volumes of water must be removed. After required treatment most of this water is re-injected or drained to superficial streams; for instances, in U.S. just 20 percent of the water could be re-injected and the rest of the water could be subject to treatments rules because of the contains of large quantities of dissolved solids that make it unfit for domestic or agricultural uses . Water handling methods for CBM exploration now exist and continue to be developed.

2.4. Economics

One of the biggest disadvantages of the coal reservoir is the delay in initial production. For the wells to produce, water first has to be drained to lower the pressure, so a producer looking for quick return on their high cost drilling and fracturing will have to consider this problem when deciding the commercial value of the well. Also, after the initial depressurization, the well usually requires compression throughout the life of the well.

A CBM development project cost can be divided into four main components, 1) field development capital cost; it considers outlays for land, permits, drilling and completion operations, infrastructure and water management, this cost varies considerable by well depth and location; an estimated for capital costs can be around U\$192,000 at 2006; 2) field operating and maintenance costs; it also considers engineering, legal and other indirect cost and it is estimated around \$1.15/ Mscf; 3) gas transportation and compression costs; it also considers cost for treatment, right of way and gas fuel consumption cost; It is estimated around \$0.70/ Mscf; and 4) other costs such as royalties for CBM ownership and production taxes; It could be in general around 35% (Bank, 2006). These values could be tentative to the Colombian case.

3. SHALE GAS

Shale is a very fine grained sedimentary rock, easily breakable into thin, parallel layers. The rock is very soft but doesn't dissolve in water (Fisher, 2005). Shale rocks act as both the source of the natural gas and the reservoir that contains it. Natural gas is stored in the shale in three forms: free gas in rock pores, free gas in natural fractures, and adsorbed gas on organic matter and mineral surfaces. These different storage mechanisms affect the speed and efficiency of gas production (NPC, 2007). Shale reservoirs can be very shallow at 76 meters to much greater depths near 2,500 meters (Warlick, 2006). For the majority, the shale layers are between 76 and 1400 meters with a thickness of around 135 meters. The Devonian shales in the Eastern U.S. are the best known. These shales were formed from sediments deposited 350 million years ago in a shallow sea which covered a large portion of the eastern U.S the kerogen present in the rock was transformed during its burial into methane and bitumen. Reservoirs of the same type very probably exist in the rest of the world. For them to contain natural gas, it is first necessary for geological conditions allowing the formation of methane from kerogen to be satisfied. The tectonic evolution of the formation should have created sufficient porosity by natural fracturing of the rock. Exploration for gas shales is similar to the exploration for conventional reservoirs which, for an unexplored basin, usually includes: (1) review of existing formation; (2) aerial surveys to gather data regarding magnetic fields, gravity and radiation; (3) seismic surveys to locate and define subsurface structures for the presence of hydrocarbons; (4) logging the wells to determine porosity, permeability and fluid composition.

3.1. Reserves

The prospective potential of a shale gas is influenced by a great number of factors such as mineralogy, texture, type and maturity of kerogen, fluids saturation, interstitial and adsorbed gas storage mechanisms, depth of the play, the temperature and the pore pressure (Boyer, 2007). To figure out the potential of a reservoir, it is necessary to know the Total Organic Carbon (TOC) within the rock, with lack of this information is not possible to accurate determine properties such as water saturation of the reservoir and the matrix porosity (Frantz, 2005). In Colombia the potential of recoverable reserves has been estimated around 32 Tcf. Similar potential additional reserves to the Valle del Magdalena Medio basin on the west mountain/Bogotá basin could exist but there are not geo-chemistries studies available that confirm such hypothesis (Zamora, 2009). Table 3 shows reserves in Colombia.

Table 3. Colombian Gas shale reserves (Zamora, 2009)

Basin	Reserves in Colombia			
	Area Km^2	Net pay m^2	GIP Tcf	Recoverable reserves Tcf
Magdalena medio	7500	100	289.5	29.0
Cordillera oriental	500	100	19.3	1.9
Cesar Rancheria	200	1000	7.72	0.8
Total shale gas	8200		316.5	31.7

Experience has shown that shale gas reservoirs must exceed or satisfy critical parameter values as listed in Table No 3

Table 4. Critical values for different parameters to define a commercial shale gas play (Boyer, 2007).

Parameters	Minimum Value
Porosity	>4%
Water saturation	<45%
Oil saturation	<5%
Permeability	>100 nanodarcies
TOC	>2%

Technical developments in gas shale exploration and production primarily have been made in Canada where has been estimated between 86 to 1500 Tcf in potential reserves (Faraj,2004) and in the U.S. where several shale gas plays are being currently developed, with recoverable reserves estimated between 500 to 1,000 Tcf. (Boyer, 2007). Accurate data about reserves worldwide is still unknown, but a rough estimation gives a figure around 16,000 Tcf as show in Table No 1

3.2. Production

Most shales have low (micro Darcy) matrix permeabilities and require the presence of extensive natural fracture systems to sustain commercial gas production rate. Fractured shales produce about 500 Bcf of gas per year in U.S. and shale gas could provide up to 15% of the recoverable gas resources in the U.S. for the next 18 years (Warlick, 2006). Shale wells are typically low rate producers, but this provides consistency for long periods of time, in the high profile Barnett Shale (U.S.), horizontal completions can average production of 1 MMscfd. In the core area, there can be 120 Bcf of reserves per square mile, meaning that a well of this type can produce for over 20 years at that stable rate. It can vary depending on the location of the reservoir and quality, but typical gas shales are average quality molecules. In some areas, there are actually potential heating values running above 1000, in the 1100 to 1200 Btu range. These are very high quality for the shale reservoirs.

One of the major players in the Barnett Shale has approximately 2800 wells that are sent to a processing plant for natural gas liquids (NGL's) extraction, and 400-500 wellhead sale wells. Those NGL's are very valuable right now in the market, and they can comprise 15% of the total saleable molecules produced in the well, including ethane, propane, iso-butane, normal butane, and natural gas liquids. The remaining 85% of the residue gas or pipeline quality methane is what's left. For the most part, the produced gas shales are dry gas that aren't processed, just sold whole.

Natural gas production from fractured shales raises tremendous problems as the case of thigh sandstone reservoirs as it will be explained ahead. Horizontal drilling and hydraulic fracturing are the most promising techniques to improve the productivity of these reservoirs.

The experience has demonstrated that even when horizontal wells cost twice as much as vertical wells, their initial production rates and their estimated ultimate recoveries are three times greater (Frantz, 2005). Shale gas has shown to be not hard to drill but certainly difficult to complete so improvements in completion technologies and multistage stimulation treatments have taken a crucial role in increasing productivity.

Diverse techniques have been used to fracturing the shale plays depending on depth and pressure. In deeper high pressure shales, operators pump a low viscosity water based fluid call slickwater, and proppant, rather for shallower formations and low reservoir pressures, nitrogen-foamed fracturing fluids are used.

3.3. Environmental Issues

Main environmental concerns are related with water sources that must be available to enable the drilling, fracturing, well completion and production operations. Between 2 and 4 million gallons of water per well are required depending on the basin and the formation (U.S. DOE, 2009), also the number of wells per section required to assure enough production enables associated water production which have to be properly managed. Experience has shown that is required between 6 to 10 horizontal wells per mile square to produce around 30 to 40 Bcf per section and an adequate water treatment before disposal should be done. Also especial emphasis has been addressed in air emissions such as NOx, volatile organic compounds, SO_2 and methane, released during operations.

3.5. Economics

Financial cost from an shale gas project investment vary according to a number of variable factors, including early-entry versus late-entry land costs, efficiency of operations, economies of scale and position on the learning curve for drilling and completion (Lyle, 2009). Real shale gas development projects in the U.S. have demonstrated that associated cost can also vary according to the reservoir characteristics, acreage, depth, gas in place per section, drilling, hydraulic fracturing, well completion technologies and operational challenges. Table 4, gives an idea of the order on investment required to develop a shale gas project in different producing basins in the U.S. In addition average economics parameters involved in the development of plays are: Internal rate of return 40%, productive life 30-40 years, decline rate 5%. New shale developments have increased the well cost dramatically, for instance wells at the Haynesville shale gas play in the U.S are about U$3.5 Million cost.

Table 4. Well cost for different shale gas plays in the U.S. (Farraj, 2004)

Shale play	New Albany	Antrim	Barnett	Ohio
well cost	$750	$300	$800	$300
Well depth(ft)	500-2500	250-1500	6500-8500	300-1000
Reserves MMscf	150-600	200-1200	500-1500	150-600

4. GAS HYDRATE

Hydrates are a special combination of two common substances, water and natural gas. If these meet under conditions in which pressure is high and temperature low, they join to form solid, ice like substance. Vast volumes of sediments in the ocean bottoms and polar regions are conductive to hydrate formation. In 1970 scientists on deep sea drilling expeditions discovered that hydrates occur naturally not only in polar continental regions but also in deepwater sediments at outer continental margins (Collet, 2000).

4.1. Reserves

It has been suggested that the volume of gas that may be contained in a gas-hydrate accumulation depends on five reservoir parameters: areal extent of the gas hydrate occurrence, reservoir thickness, sediment porosity, degree of gas hydrate saturation and the hydrate gas yield volumetric parameter, which defines how much is stored within a gas hydrate. A cubic volume of hydrate contains gas that will be expand to somewhere between 150 and 180 cubic volumes at standard pressure and temperature. In general terms there are about 700,000 Tcf of methane are locked up in hydrates. About 99% of these are in marine sediments offshore. The total is about two orders of magnitude greater than the amount of conventional recoverable methane, which is estimated to be 6,262Tcf (Correa, 2008). In Colombia it has been estimated that around of 400 Tcf in situ and there is not profitable technology to produce it. Table 5 shows reserves estimated for Colombian gas hydrate

Table 5. Colombian Gas Hydrate (Zamora, 2009)

Colombian Gas Hydrate				
Basin	Area Km^2	Net pay m^2	Gas content m^3 NG /NGH	GIP Tcf
Caribbean	37,500			217.1
Pacific	37,500	1		217.1
Potential NGH	75,000	1	164	434.2
			164	

4.2. Production

The first known example of gas production attributed to hydrates occurs in the Siberian Messoyakha gas field in the 70's and together with other gas fields in the same region contain about 777 Tcf; no other development project was implemented until Mallik field in Canada was developed in 2002 (Sloan, 2008). After the gas hydrates in the Messoyakha, and Mallik fields, those in the Prudhoe bay Kuparuk river in Alaska are the next most studied hydrate accumulations in the world (Collet, 2000).

There are three principal methods to recover methane from hydrates are under consideration:

Depressurization: the pressure of the gas hydrate is decreased sufficiently to cause dissociation. This method is feasible only when associated free gas can be produced to decrease hydrate reservoir pressure, as has been reported in the Messoyakha field.

Thermal injection: In the absence of a free gas zone beneath the hydrates, thermal injection, or stimulation may be a viable solution. Heat is added to the gas hydrate bearing strata to increase the temperature enough to cause the hydrate to dissociate. An example of this method is injection of relatively warm seawater into offshore gas-hydrate layer.

Inhibitor injection: Injection of inhibitors such as methanol shifts the pressure-temperature equilibrium so that the hydrates are no longer stable at their normal conditions and methane is released.

Of the three methods, dissociation by warm water injection may be most practical. Gas hydrates will become a potential resource only when it can be shown that the energy recovered is significantly greater than the energy required to release methane gas (Collet, 2000).

Japan, India U.S., Canada, Norway and Russia are among the countries with ongoing gas hydrates investigations. Canada has enormous potential reserves of hydrate gas.

4.3. Environmental issues

Natural gas hydrates play a significant role in global warming and geohazards (Sloan, 2008). An increase in temperature can trigger a release of methane, a powerful greenhouse gas with 20 times the radiative capacity of CO_2 and which eventually could be converted into CO_2 in the atmosphere, increasing the green house effect. Other environmental concerns are related with the release of methane from hydrate seams by mechanical processes; drilling and production operations can involve gas leakage as a result of geomechanical instabilities in the wellbore.

4.4. Economics

Development and production of natural gas hydrate resources are in experimental stage, thus, a real cost can not be known at this time. Estimates of hydrate production have been established as a basis and are illustrated in Table 6.

Table 6. Estimated economics for a hydrate gas project development. (Collet, 2003)

Hydrate production economics*			
	Production method		
	Thermal injection	Depressurization	Conventional gas
Investment (M U.S. $)	5,084	3,320	3,150
Annual cost (M U.S.$)	3,200	2,510	2,000
Total production(MMcf/year)**	900	1,100	1,100
Production cost(US$/Mcf)	3.60	2.28	1.82
Break even wellhead price(U.S.$/Mcf)	4.50	2.85	2.25

*Assumed reservoir properties h= 25ft, Φ = 40%, K = 600mD

** Assumed process: injection of 30,000b/d of water at 300F

5. TIGHT GAS

Tight gas is defined as gas contained in sedimentary rock formations in which the layers are so tightly packed and cemented together that the gas flow "greatly hindered" (Wilson, 2008). This means that even though the gas is known to exist in large quantity, it does not flow easily toward existing wells for economic recovery. In that sense the reservoir has to be produced by well stimulation (large hydraulic fracturing treatment) or using a horizontal wellbore or multilateral wellbore (Stephen, 2006). Mainly Tight gas is associated with low permeability sandstone and limestone formations, Low permeability may stem for two different factors: - the mineralogical composition of the porous medium; thus, the presence of a mixture of shales and fine sediments lead to the formation of a dense, nonporous medium. - The depth of the reservoir which causes compaction of the porous medium (Rojey, 2000). Tight gas has been generated somewhere else (most likely in a shale) and has migrated to the tight formation where it is trapped and stored in interparticle, slot and microfracture porosity (Aguilera, 2009). It exists in underground reservoirs with microDarcy range of permeability and very low porosity. The quality of this gas is comparable with that of traditional gas wells, but the quality of the rock is not.

5.1. Reserves

The unconventional gas reservoir production is available at the specific regions in the world because of its high production cost. By far U.S. is a country which has more data about unconventional reservoir than any other; however, the originally in place resources are enormous and the recovery technology is still under developing. Table 1 shows reserves of U.S. and rest of the world by regions. It is important to notice the importance of the U.S. in production of unconventional reservoirs so before year 2000 only U.S. produced unconventional gas compared with the rest of the world. Development activities and production of gas from tight gas reservoirs in Canada, Australia, Mexico, Venezuela, Argentina, Indonesia, China, Russia, Egypt and Saudi Arabia have occurred during the past decade (Holditch, 2006). In Colombia preliminary analysis estimates around 1.2 Tcf in situ. The Cordillera Oriental (CO)/Magdalena medio (MM) is the region in which is found Colombian tight gas reservoirs as shown in Table 7.

Table 7 Colombian tight gas reserves (Zamora, 2009)

Colombian tight gas reserves					
Region	Area	Gross pay	Pay volume		GIP
	Km^2	m	Acre-feet	Tcf	Tcf
CO. /M.M	4000	200	648,570,555	28.3	1.2
Total reserves	4000		648570555	28.3	1.2

5.2. Production

Historically since 1960 U.S has been producing more tight gas than other unconventional resources and it is the largest source of unconventional production up to date, accounting for 32% of total U.S currently and forecasted production through 2030 (EIA, 2009). The U.S production of thight gas is close to 6.15 Tcf of the total consumption of natural gas around 19.30 Tcf in 2007.

In tight gas reservoir the main solution employed to improved productivity is hydraulic fracturing. This helps to fracture the porous medium and thus to boost the productivity of the wells which communicate with the fractures created. Another technique for improving well productivity is horizontal drilling. This substantially increases the length of the drain and thus boots the production of the well by a factor of up to 4 or 5 in favorable situations (Rojey, 2000); however, there are some improvements to make such as reduce the foot print and improve the directional drilling that should be cared in the near future to guarantee a major success. Other issues to improve this kind of reservoir are: As horizontal drilling techniques speed up the flow of gas in order to stay on the treadmill, they change the ultimate depletion profile of the resource (Rojey, 2000). So the most disadvantage of this drilling technology is its limited completion options and high cost of drilling. New technologies will be care about it. The overall current commercial success rate of horizontal wells in the U.S. appears to be 65%. Even though the success rate improves as more horizontal wells are drilled in the given formation in a particular area, the rate

horizontal wells are drilled in the given formation in a particular area, the rate isn't encouraging. This means, initially it is probable that only 2 out of the 3 drilled wells will be commercially successful. In turn, this creates extra initial risk for the project (Joshi, 2003).

The major demerit of horizontal wells is that, only one zone at a time can be produced using a horizontal well. If the reservoir has multiple pay-zones, especially with large differences in vertical depth, or large differences in permeabilities, it is not easy to drain all the layers using a single horizontal well. In the U.S., a new horizontal well drilled from the surface, costs 1.5 to 2.5 times more than a vertical well. A re-entry horizontal well costs about 0.4 to 1.3 times a vertical well cost. The overall current commercial success rate of horizontal wells in the U.S. appears to be 65%. Even though the success rate improves as more horizontal wells are drilled in the given formation in a particular area and smaller areas are required, the rate isn't encouraging.

Technology is the biggest factor in the progress of the continued growth of this type of hydrocarbon. There were 6543 Tight gas sand wells in North America in 2005, producing approximately 7.7 Bcfd. In order to drain a section of land for a tight gas reservoir, it may require around thirty wells to perform at the same level as conventionally spaced wells. This is why it will be necessary to learn more about the geology of these formations and how to more efficiently produce them for it to be an economic endeavor. There is effectively 1,371 Tcf of Ttight gas sand reserves in North America alone. New technologies are vital to improve recoveries, efficiencies, and deliverability across the non-conventional supply chain. Therefore, technology should continue to advance to enhance the overall ability to accumulate the most reserves from non-conventional resources.

5.3. Environmental issues

The US Government wanted to increase natural gas production over the next 20 years by 50 percent while the actual production rate of unconventional gases consists of 17 Bcfd for tight sand gas, 5 Bcfd for coal bed methane, and 3.2 Bcfd for shale gas (EIA, 2009); However, there are some environmental issues that must be taken into account before developing unconventional gas; such as land regulations, well sites, well density, flaring, dewater management, noise concerns, wilderness, wild life impacts, and plugging and abandonment concerns. EIA estimates daily delivery capacity of the pipeline grid to be 119 Bcf. Nevertheless, in order to produce unconventional reservoir it is required to extend the net gathering and interstate pipeline to reach markets which go against of environmental issues so laws has to be flexible in the future to allow new investments.

Respect to the regulations that need to be reconsidered let see this example. The Bureau Land Management(U.S.) imposes three different kinds of stipulations that affect natural gas development: Standard stipulations that place limits on operations, such as prohibiting development within 500 feet of surface water or riparian areas and are typically applied to all oil and gas leases; seasonal or other special stipulations that prohibit activities during specified time periods when suggested by the Fish and Wildlife Service or others to protect nesting, calving, and other seasonal habitat use; No surface occupancy stipulations that prohibit operations directly over a leased area and require directional drilling to protect underground mining operations, archaeological sites, caves, steep slopes, campsites, or wildlife habitat. All of those are regulations that need to be considered to be more flexible in the future.

5.4. Economics

Tight gas reservoirs development entails much more intense investment and activity than conventional gas. Unconventional tight gas development requires many wells; the wells decline by 60-70% during the first year and recover about one half of their recoverable gas in 5-6 years, with the remaining gas produced in the next 6-40 Years.

Economics are related with technology development, in that sense, innovations in drilling, completions, reservoir characterization and stimulation techniques have allowed development of the tight gas resource. Other factors such as high commodity prices and low cost of fracturing technologies result in improved resource economics.

Drilling, producing and completing a 1 Bcf well could be around U.S. $600,000 and generates about 65% rate of return, also drilling a 15,000 ft wells cost U$3 to U$4 million and yields production of 3-4 Bcf. (OGI, 2006).

6. GENERAL CONSIDERATIONS

There are common problems associated to produce unconventional reservoirs such as environmental issues, political risks, improve technologies, oil prices. All of them will be considered to invest in a unconventional gas reservoir project.

There are similar methods to improve production in unconventional gas reservoirs such as massive fracturing, directional drilling, multilateral wells and reduce the food print due to the number of well required to be an economical project.

Colombia is already developing some projects of CBM, for the rest of unconventional reservoirs it will be necessary new improve technologies and feasible technologies to develop projects in that sense.

7. NOMENCLATURE

CBM: Coal Bed Methane

GIP: Gas in place

NG: Natural gas

NGH: Natural gas hydrate

Tcf: Tera cubic feet

Mscf: One thousand standard cubic feet

MMscfd: Millions of standard cubic feet per day

DOE Department of energy

M.E: Middle East

Bcfd: Billions of cubic feet

Tcf: Tera cubic feet

TIP: Total in place

g: Gravity

h: Formation thickness, ft

k: Permeability, milidarcy (mD)

P, p Pressure, psi

U.S. United States of America

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