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Challenges and opportunities for the development of Shale resources in Colombia

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Challenges and opportunities for the development of Shale resources in Colombia

by

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Thesis

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Dedication

This thesis is dedicated to my parents, Ligia and Juan Pablo. My beautiful wife, Natalia and my brothers Juanita and Santiago. Without your support I would have never moved from my comfort zone and pushed myself to higher limits. Finally, to my best friend, Javier Muñoz, there is a lot of you in this thesis and in achieving this Master's.

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Abstract

Challenges and opportunities for the development of Shale resources in Colombia

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After the success of shale gas development in the United States, countries around the world are looking within their own territories for the possibility of replicating the U.S successes in order to achieve financial and/or energy security objectives. Such enterprise has shown to be not as easy as it might have been perceived to be. Some countries like Argentina, China and Poland, where large reserves of shale resources have been identified, have struggled to obtain beneficial results from their shale operations, with the result that even the more optimistic operators are now showing more caution and are reviewing everything before making any commitments to operate in countries with identified shale resources.

Colombia, a country with strong oil and gas roots in its economic history, is actively attempting to attract operators to explore and produce their shale resources. If successful, these efforts have the potential to bring increased foreign investment to the country, while also improving Colombia's oil and gas reserves, which have been declining over the last five years. This thesis, will address the challenges and opportunities of the development of shale resources in Colombia that operators will face by reviewing several critical aspects of the process. This thesis begins with a discussion of the geology of shale resources in Colombia, followed, first, by a review and analysis of the fiscal and contractual regime established in Colombia for the oil and gas industry, then, second, a risk analysis of possible Colombian shale operations, then third, a financial analysis of a possible shale project and, finally, ends with a summary of the challenges and opportunities an operator could face based on the analysis of the previous topics.

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INTRODUCTION AND BACKGROUND OF SHALE GAS RESOURCES IN COLOMBIA

By the end of the last millennium the United States was completely pessimistic about its oil and gas reserves. The situation was such that few would have predicted the current abundance of gas and new oil reserves derived from shale gas operations. The key change factor has been the application, of the existing technique of hydraulic fracturing to the recovery of hydrocarbons from shale formations. Based on these operations, an anemic U.S. oil and gas industry began its recovery returning to its former position as a prosperous oil and gas country. Nowadays, the U.S. is close to being energy independent, and becoming the largest oil producer in the world by 2015. The large amount of imports of gas have almost completely stopped and LNG import terminals around the country are now asking permission to become exporting facilities. This situation has lead to an economic boom in many different parts of the country. Shale gas development has revolutionized the whole energy industry and has stimulated the energy markets (Yergin, 2013). Consequently, because of what is happening in the United States, different countries around the globe want to be part of this shale boom. By the end of the last decade the search for shale gas in unexplored shale deposits had begun all around the globe, in both established petroleum-producing countries and in countries with no previous, or only emerging, operations.

Following the boom in the U.S., Colombia, like many other countries in South America with economies strongly linked to the oil and gas industry, began its own search for unconventional resources, especially shale gas and coal bed methane ("Resolución No. 18 1495 de 2 de Septiembre de 2009"). It is difficult to determine exactly when the rush to find hydrocarbons in shale started in Colombia, but by around 2009-2010, a few operators (Sintana Energy, Nexen, Canacol and Ecopetrol) had begun drilling exploratory stratigraphic wells in an attempt to map the subsurface and determine the presence of hydrocarbons (Kuuskraa, Stevens and Moodhe, 196). By April 2011, following the publication of the The U.S. Energy Information Administration (EIA) report on *World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States* indicating possible shale gas resources in Colombia, the frenzy began in earnest. The EIA report estimated that Colombian shale deposits could have the potential for producing at least 19 trillion cubic feet (Tcf), enough to satisfy 2012 consumption levels of natural gas for about 40 years; this report did not provide figures for shale oil (Kuuskraa, 104).

The importance of such potential petroleum reserves cannot be underestimated by only considering the numbers. Those early figures have created a level of high interest in developing those resources, from both private and public entities. Small and large, international and national, operators everywhere see the possibility to either grow new reserves or renew their declining ones, or, at least, to do some M&A or farm-in/farm-out options to increase their capital. For the Colombian government, as well as the citizens of Colombia, shale resources could produce increased revenue to the country via royalties from producers, but most importantly, these new resources represent a possibility to increase Columbia's oil and gas reserves, which have been decreasing in the last decade. Based on the information in the BP Statistical Review of World Energy released in June of 2013, Colombian reserves would only last for about 6.4 years before it would be necessary to start importing oil from other countries based on the 2012 consumption rate of 274,000 barrels of oil per day and 2.2 billion estimated barrels of reserves. The situation for gas as of 2012 was not as critical, considering that the current production rate of 1.15 billion cubic feet (BScf) is sufficient to support the current consumption rate of 0.95 BScf, even allowing for export part of that excess to Venezuela ("BP Statistical

Review of World Energy June 2013"; Crooks, 2011). However, in the last 10 years the estimated total vs. proved reserves has declined drastically with only 5.7 Tcf of proved reserves for 2012. Based on this figures, Colombia only has about 13 years before they have to start importing gas from neighboring countries ("BP Statistical Review of World Energy June 2013"). Furthermore, according to the Mineral and Energy Planning Unit -Unidad de Planeación Minero Energetica- (UPME), there is a high probability that consumption will rise sharply in the next 10 years as natural gas is being more popular among end consumers, also as industries switch from coal and oil to natural gas and finally as consumption continues to increase in the transportation sector (Cadena, et al., 2013).

This appears to be a win-win situation given the needs of the oil and gas companies and the Colombian citizens and government, however, all that glitters is not gold. In other parts of the world, exploration and production of shale resources have not proved to be as easy as they have been in the U.S. (Beckwith, 42-46). New plays and basins entail different challenges and opportunities to operators willing to acquire and produce these resources. This thesis attempts to identify the challenges and opportunities that might face an operator interested in developing shale resources in Colombia. Specifically, this thesis begins with a discussion of the geology of shale resources in Colombia, followed by a review and analysis of the fiscal and contractual regime established in Colombia for oil and gas, then a risk analysis of Colombia for possible shale operations, next a financial analysis of a possible shale project and ends with a summary of the challenges and opportunities an operator could face based on the analysis of the previous topics.

CHAPTER 1. SHALE RESOURCE OPERATIONS

Background

HISTORY AND DEFINITIONS

Shale gas and shale oil only became noteworthy in the last decade when production started to flow consistently in high quantities from different plays like the Barnett and Eagle Ford shale plays in Texas, the Marcellus shale play in the northeast or the recently discovered Bakken shale play in the Midwest (figure 1). However, before becoming the phenomenon that shale is today, making people believe the U.S. could become energy independent or a net gas exporter nation (Yergin, 2013), shale was just one of the many projects the federal government funded in the 80's trying to find a supply alternative for gas (EIA, 2011).

Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

Figure 1. Lower 48 states shale plays as of 2011. Source: EIA, 2011.

Shale gas production derives from the use of two old techniques in the oil and gas industry from shale formations: horizontal drilling and hydraulic fracturing. The use of these two techniques enabled the operators to produce natural gas from shale formations, which are characterized by low permeability and in some cases decent porosities (figure 2) (EIA, 2011). However, before their wide use for shale resources, these two techniques were used for conventional wells. As its name suggests, horizontal drilling is basically a drilling technique used as part of the process of making contact with the hydrocarbons, while fracturing or well stimulation was primarily applied as an Enhanced Oil Recovery (EOR) technique in vertical wells. Thus, there was normally a big time-gap between the utilization of each technique in the lifecycle of a conventional oil field -Drilling at the beginning and EOR much more towards the end of the life of the well- (Bommer, 2013).

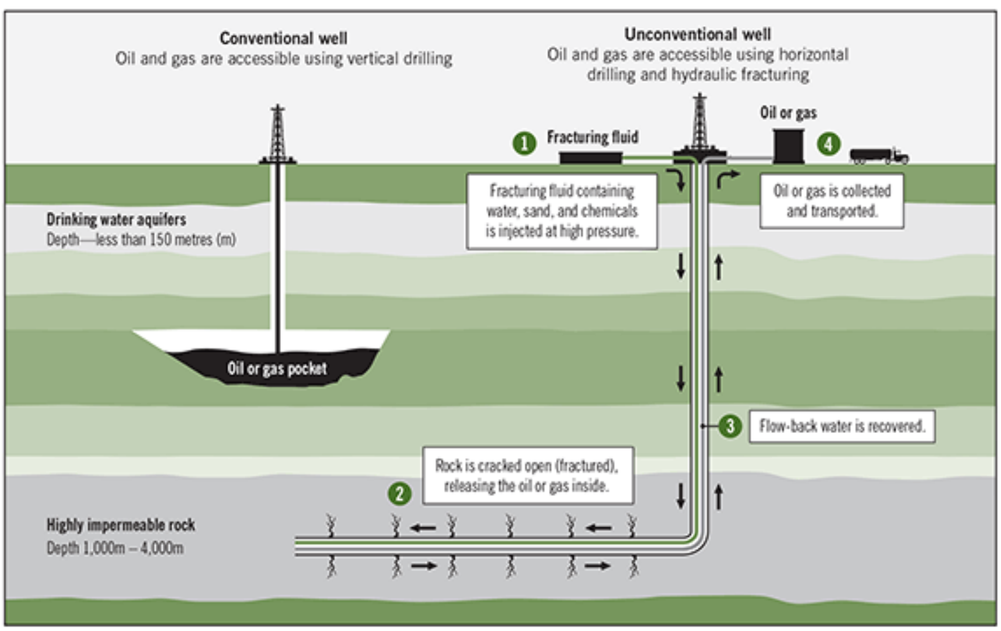

Figure 2. Classic layout of conventional and unconventional wells, with explanation of the hydraulic fracturing process. Source: "Report of the Commissioner of the Environment and Sustainable Development to the House of Commons – Chapter 5 Environmental Petitions", 26.

Hydraulic fracturing is defined as “a stimulation treatment routinely performed on oil and gas wells in low-permeability reservoirs, [which uses] specially engineered fluids [that] are pumped at high pressure and rate into the reservoir interval to be treated, … [in order to cause] fractures to open” (“Hydraulic Fracturing”). It has been used since the early days of the oil and gas industry tracing back to the 19th century. However, it was not until 1949 that hydraulic fracturing was formerly introduced in the United States. After Stanolind Oil proved the benefits the technique had in 1949, it became a powerful technique to stimulate oil and gas production that as of December of 2010 has been performed almost 2.5 million times worldwide (Montgomery and Smith, 2010).

On the other hand horizontal drilling, which is “a subset of the more general term "*directional drilling*," used where the departure of the wellbore from vertical exceeds about 80 degrees, … [has become more popular] because a horizontal well typically penetrates a greater length of the reservoir, [thus] it can offer significant production improvement over a vertical well [to the operator]” (“Horizontal Drilling”). Early practical applications of horizontal drilling began in the early 1980s when downhole support equipment had advanced enough to make this technique possible (EIA, 2011).

The use of horizontal drilling and hydraulic fracturing techniques to produce gas from shale formations under commercial conditions became only possible after a partnership among the U.S. Department of Energy (DOE), the Gas Research Institute (GRI) and private operators in the mid-1970’s. This partnership led to the development of these technologies and also the development of unique applications for shale formations like multi-stage fracturing and slick-water fracturing. Nevertheless, large-scale shale gas production did not occur until Mitchell Energy and Development Corporation proved commercial production from the Barnett Shale in Texas in the late 1990’s. After the success was conclusive, other companies moved into this reservoir and, applying those two techniques, made the Barnett Shale play one of the most significant gas sources for the U.S. producing almost half trillion cubic feet per year in 2005. After operators got confidence in the ability to produce natural gas profitably in the Barnett Shale, they spread all over the U.S. in now well-known shale formations like the Marcellus, Eagle Ford, Haynesville, among others (figure 1) (EIA, 2011; Montgomery and Smith, 2010).

EQUIPMENT

The equipment used for the production of shale resources should be divided into the equipment for the horizontal drilling operation and for the hydraulic fracturing operation. For the sake of this thesis and to provide the reader with a big picture view of the topic, the starting point will be to determine that the most important equipment for the horizontal drilling job is a rig that is capable of directional drilling. That being said, not all rigs are capable of directional drilling. Additionally, for the completion of complex directional drilling operations, like horizontal drilling, it is necessary to use “a bend near the bit, as well as a downhole steerable mud motor”. These equipment will direct the bit in a different direction from the initial wellbore axis, thus helping reach the specific angle the drilling needs to have to get to the paid zone of the reservoir (unconventional well in figure 1) ("How Does Directional Drilling Work?").

For hydraulic fracturing operations, the most important equipment required for a fracturing job consists of: a fracturing blender, one or more high-pressure, high-volume fracturing pumps, and a monitoring unit. Less important but still required, hydraulic fracturing operations for shale resources also require: fracturing tanks, sand/proppant and chemical storage units or tanks, a chemical injections unit, and different hoses and gauges (figure 3)(Montgomery and Smith, 2010; “Hydraulic Fracturing – The Process”).

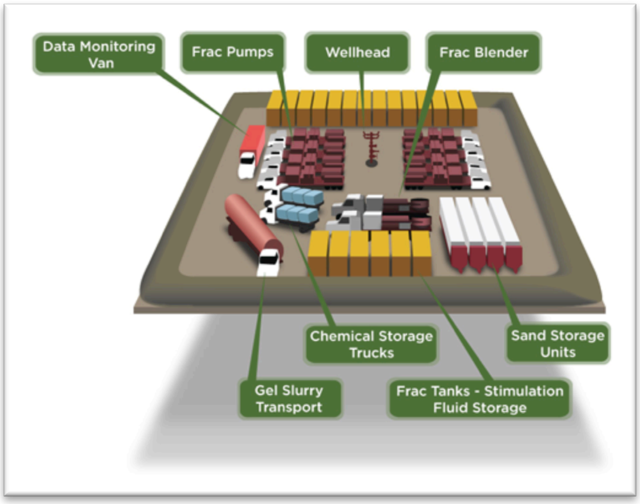

Figure 3. Hydraulic fracturing operation surface equipment. Source: “Hydraulic Fracturing – The Process”.

Criticality

Defining which equipment is more critical than another is a difficult task, because of the personal approach that someone can have when making such judgment. This is especially true for hydraulic fracturing equipment. According to Paul Bommer, the blender is the most critical piece of equipment for a “frac job”[1] as it precisely mixes all the fluids required in the operation. Additionally, as he explained to his students in the Production and Design Technology course “…the only equipment you should be aware not to loose in your operation is your blender. If your blender gets damaged, the option of getting a new one to finish your job on time is minimum. All service companies have their equipment rented in this new gas boom…” (Bommer, 2013). A different opinion is the offered by Rory Sweeney of Chesapeake. According to him the data van (monitoring unit) is the most important one because it is where the operator keeps track of all the fracturing operation (Williams, 2013).

[1] Frac job is the way operators normally called or refer to the operations involved in performing hydraulic fracturing operations in shale formations.

CHAPTER 2. GEOLOGY OF SHALE GAS RESOURCES IN COLOMBIA

In the report prepared for the U.S. Energy Information Administration (EIA) "*World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States"* Advance Resources International (ARI), defined two different regions within South America that have the potential of having shale gas resources: Northern South America and Southern South America. Northern South America includes Colombia and Venezuela while Southern South America is comprised of Argentina, Bolivia, Brazil, Chile, Paraguay and Uruguay (figure 4)(Kuuskraa, 2011).

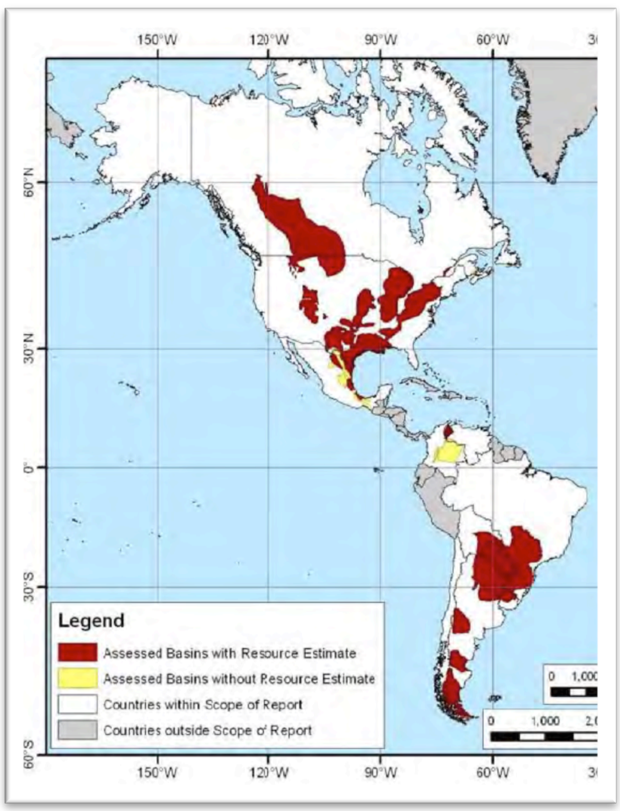

Figure 4. Snapshot of American Shale gas resources defined by ARI. Source: Kuuskraa, 2011.

In their 2013 study "*EIA/ARI World Shale Gas and Shale Oil Resource Assessment*" ARI makes new distinctions in their evaluation of South America. First, while Colombia and Venezuela continue to comprise Northern South America; they create a separate category for Argentina and Brazil, thus redefining the Southern South America section, which now includes only the assessments for Bolivia, Chile, Paraguay, and Uruguay (Kuuskraa, Stevens and Moodhe, 4). Additionally, the new study provides a thorough assessment of the technically recoverable shale gas and shale oil within each of the shale formations covered in the study. The addition of shale oil to the report, plus the thorough quantitative analysis of each shale play, coupled with a wider or deeper analysis of either the countries, basins or plays makes this study the seminal publication for different stakeholders interested in understanding the situation of shale gas and shale oil in South America and in the world.

While other countries within South America like Peru and Ecuador have presented at different conferences their geologic assessments and perspectives regarding their shale resources (Torres M., 2013; Sánchez, 2013), ARI did not include them, based on the lack of public information available at the time of the study. Future updates of this study or new ones from different entities will probably include these and other countries as information is verified and becomes publicly available and more widely disseminated.

The following pages will present a brief discussion of the reservoir properties widely believed to be important in the analysis of shale plays in the oil and gas industry, followed by a description of the relevant aspects concerning the basins and shale plays of Colombia.

Reservoir Properties in Shale Gas and Shale Oil Formations

There are many more shale plays in the world than the ones that make a headline in the news or the ones that are reported in science papers or reports like the one published by Kuuskraa, Stevens and Moodhe in 2013. The difference between the ones that get attention and the ones that do not lies in the *prospectivity* of the plays(i.e. their ability to produce hydrocarbons). As defined in the Kuuskraa, Stevens and Moodhe report, the *prospectivity* of a play is the analysis of its geological and reservoir properties to determine the potential of the play to produce hydrocarbons. This analysis is a major step for "assessing the in-place and recoverable shale gas and shale oil resources" within a play (Kuuskraa, Stevens and Moodhe, 27) and, from a commercial point of view, is probably one of the most relevant pieces of data required to determine if a play will be worth being explored by a company.

Based on the information presented by ARI in its "*World Shale Gas and Shale Oil Resource Assessment*", coupled with the class presentation on shale reservoirs by Stephen Ruppel in the Reservoir Geology and Advance Recovery course, some of the key items that are analyzed to determine the *prospectivity* of a shale play are (Kuuskraa, Stevens and Moodhe, 28; Ruppel, 2011):

- Depositional environment of the shale,
- Depth of the shale interval,
- Total organic content (TOC, by wt.),
- Type of Organic Matter,
- Thermal maturity (Ro)

The following is a brief explanation of these key items.

Depositional Environment. This key criterion refers to "the area in which and physical conditions under which sediments are deposited, including sediment source" ("Depositional Environment"). In the case of shale, whether or not its depositional environment was marine influences on the brittleness of the shale. The more brittle the shale is the more favorably it will respond to hydraulic fracturing. Marine-deposited shale will tend to have higher brittleness, while non-marine-deposited shale (lacustrine, fluvial) will tend to have lower brittleness (Kuuskraa, Stevens and Moodhe, 32).

Depth. The depth criterion refers to the depth at which the shale formation is present below the surface. The depth of the formation would affect its prospectivity in different ways. On one hand formations shallower than 3,300 ft. tend to present lower reservoir pressure, which will affect the recovery of the hydrocarbons in place, additionally "shallow shale formation have risks of higher water content". On the other hand formations "deeper than 16,500 ft. have higher pressure but also have risks of reduced permeability and higher drilling and development costs" (Kuuskraa, Stevens and Moodhe, 33).

Total Organic Content (TOC). TOC refers to "the concentration of organic material in source rocks as represented by the weight percent of organic carbon". The minimum value for a conventional source rock is 0.5% while for shale gas reservoirs the minimum is 2% (Depositional Environment"). The percentage present in the reservoir coupled with the kerogen type present in it (Types I, II, III and IV) will determine highly the hydrocarbon type and potential of the shale formation (Kuuskraa, Stevens and Moodhe, 33).

Type of Organic Matter. There are two major sources of organic matter: terrestrial and oceanic. Terrestial organic matter is composed of land plants and algae, and accumulates principally in lakes, estuaries and some restricted marine basins. On the other hand, oceanic matter is composed of phytoplankton, zooplankton and fecal pellets, and accumulates principally in restricted marine basins (Ruppel, 2011). The source of the organic matter will determine the kerogen group type in which it will be classified (I, II, III or IV). This classification is based mostly on the measurement of the hydrogen and oxygen content of the organic matter. Basically, Type I is oil prone, Type II is related to wet gas and condensates, Type III is gas-prone and Type IV does not have the potential for hydrocarbons (figure 5) (Potter et al., 268-269).

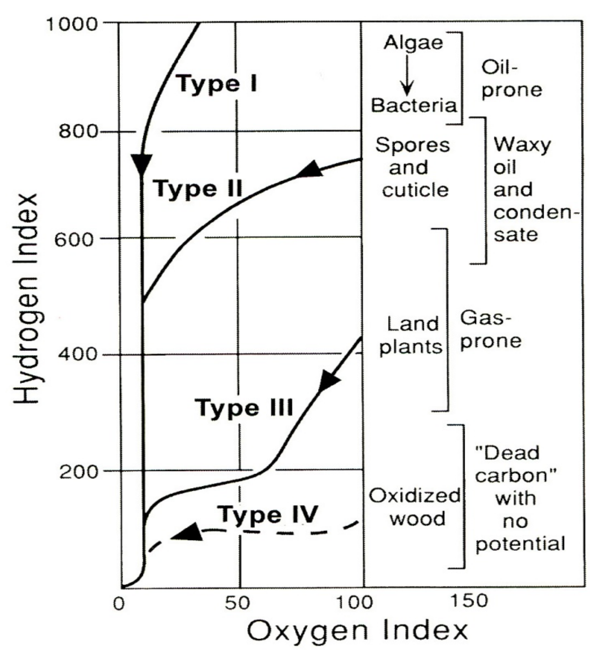

Figure 5. Types of Organic Matter (kerogen) based on hydrogen and oxygen index.
Source: Potter et al., 269.

Thermal Maturity. Thermal maturity indicates the degree of heating that a source rock has been exposed to in the process of transforming organic matter into hydrocarbons. It is commonly evaluated by measuring “the reflectance of certain types of minerals (Ro%)” in the source rock. Oil prone prospective areas will have an Ro greater than 0.7% but less than 1.0%. Condensate and wet gas prospective areas tend to have an Ro between 1.0% and 1.3%. And finally, dry gas areas typically have an Ro greater than 1.3% but lower than 3.3%. Higher than that Ro, it is considered that the kerogen is super mature and that the window for developing hydrocarbons is gone (figure 6) (Kuuskraa, Stevens and Moodhe, 33; Ruppel, 2011).

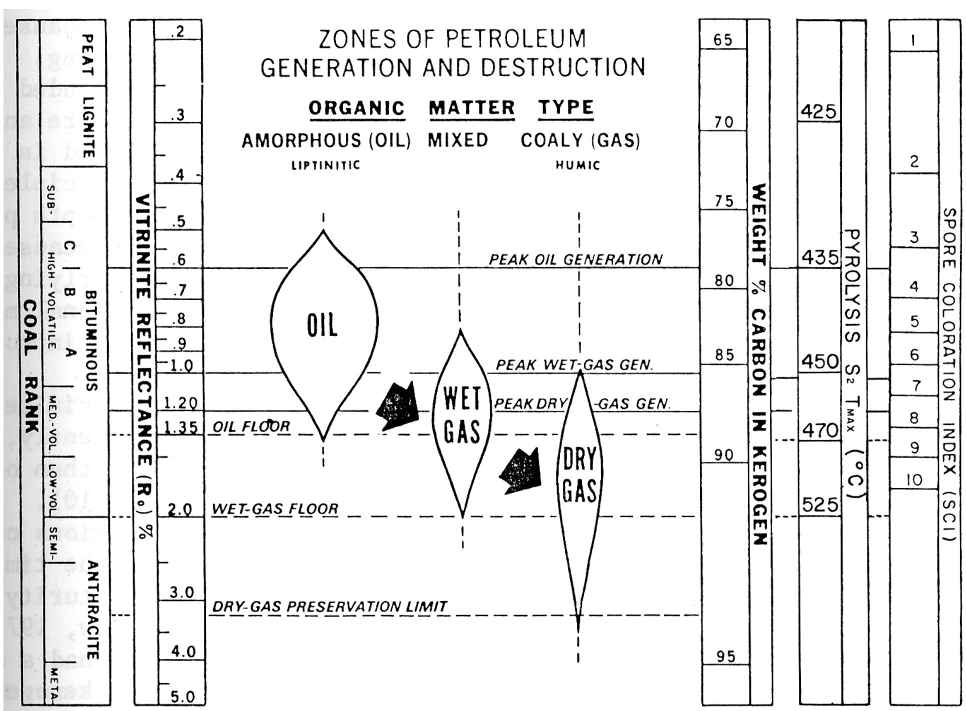

Figure 6. Thermal Maturation Scale. Source: Ruppel, 2011 from Zimmerle, 1995.

Colombia

COLOMBIAN GEOLOGY FRAMEWORK

Introduction

Colombia is located in the northwestern corner of South America, which has undergone a unique series of geologic events that in turn have produced the distinct characteristics of its sedimentary basins such as their distribution, genesis, bounding structures and basin fill. Colombian basins have gone through changes in shape and direction caused by multiple series of rifting events and oblique collisions followed by transpression and transtensional tectonic deformations. Those changes took place principally from the Paleozoic to Late Cenozoic eras; and as a result the tectonic evolution of Colombian basins is considered to be a *poly-history* evolution. Consequently, the knowledge from basin to basin varies from a structural or stratigraphical perspective as knowledge of a particular basin's evolution depends on the specific aspects which any one entity has researched. In the end, this complicates comparison between basins and, ultimately, requires the understanding of the character of each unique basin and its specific prospectivity (Barrero et al., 2007).

Colombia can be divided into three main tectonic areas: 1) The Eastern region covers all the central and southeast areas of the country, and is bounded on the west by the foothills of the Eastern Cordillera (figure 7). Its basement is composed of Paleozoic and Precambrian formations, and is covered by Paleozoic-Cenozoic formations that have experienced mild deformation; 2) The Central region, covers the Eastern Cordillera up to the Sierra Nevada de Santa Marta and the Central Cordillera, including the Magdalena River valley, and is delimited by the Romeral fault system on the northwest (figure 7). Its basement is comprised of Grenvillian formations believed to have accreted during

Paleozoic times, covered by a sedimentary-methamorpic formation; 3) The Western region covers the onshore and offshore land west of the Romeral fault system (figure 7). It is composed of Mesozoic-Cenozoic oceanic terrains accreted onto the Continental margin during Late Cretaceous, Paleogene and Neogene periods (Barrero et al., 2007).

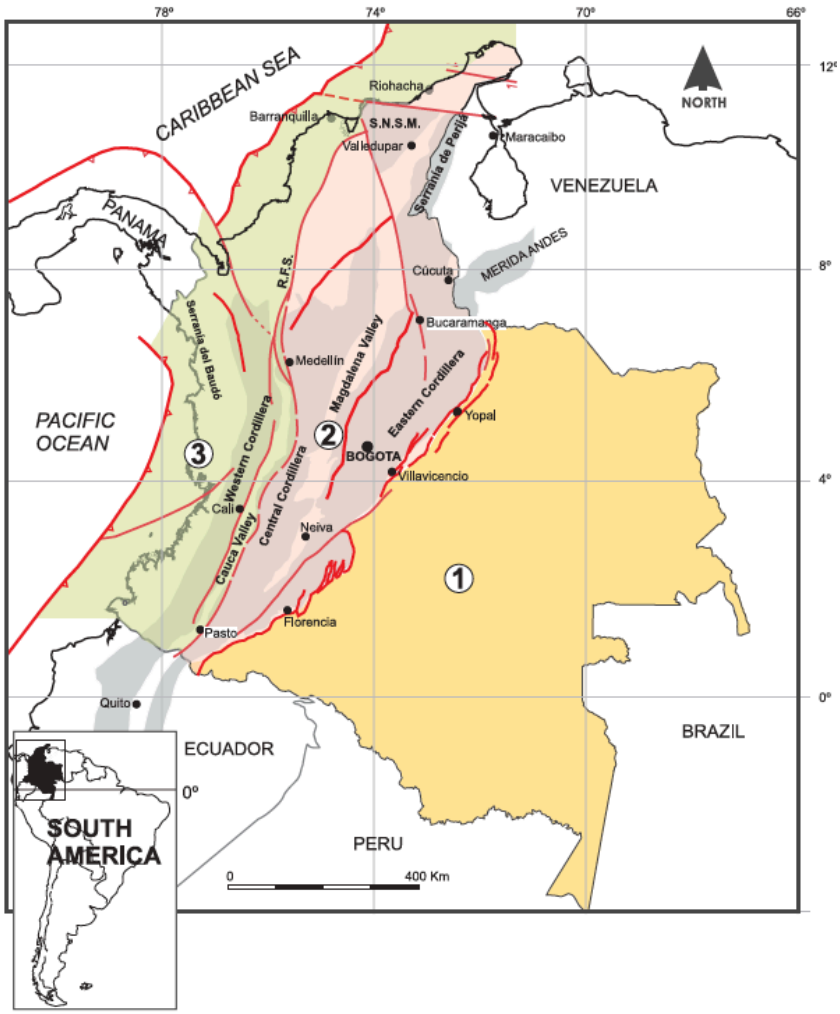

Figure 7. Main tectonic domains map of Colombia. Source: Barrero et al., 2007.

Hydrocarbon-related Geology Formations

According to various authors cited in Barrero et al, 2007, most of the Colombian sedimentary basins were developed in the Late Triassic period during the break-up of Pangea. Sediments from the Early Jurassic to Lower Cretaceous periods were deposited in a highly irregular rift system formed in a northwest-southeast-northeast trend covered by Upper Cretaceous to Neogene sedimentary formations (Etayo et al., 1976; Fabre, 1983; Barrero, 2000; Rolón et al., 2001 qtd. in Barrero et al., 2007). The post-rift phase of the system is believed to have gone through different processes during Middle Albian and Turonian times that gave birth to organic-matter-rich sediments, which in turn gave birth to the source rocks responsible for generating most of the hydrocarbons found in Colombia (Barrero et al., 2007).

Colombian Basins: Nomenclature and Boundaries

Since 2007, after the Agencia Nacional de Hidrocarburos (ANH) published the book *Colombian Sedimentary Basins: Nomenclature, Boundaries and Petroleum Geology, a New Proposal*, Colombia was officially divided in 23 sedimentary basins (figure 8). According to Barrero et al., it is important to clarify that some of the regions included in the division do not meet all the parameters required to be classified as a sedimentary basin. Instead, they are described more accurately by the USGS (2000) definition of Geological Provinces.[2] Subsequently, their limits are drawn along natural geologic boundaries or at defined water depths in the oceans. However, the term sedimentary basin has been kept, as it is common in the geological literature of Colombia

[2] The USGS (2000) definition of Geological Provinces states, "each geologic province is an area having characteristic dimensions of perhaps hundreds to thousands of kilometers encompassing a natural geologic entity (for example, sedimentary basin, thrust belt, delta) or some combination of contiguous geologic entities", in Barrero et al., 2007.

and widely used by the ANH in their bidding rounds and presentations in different E&P scenarios (Barrero et al., 2007).

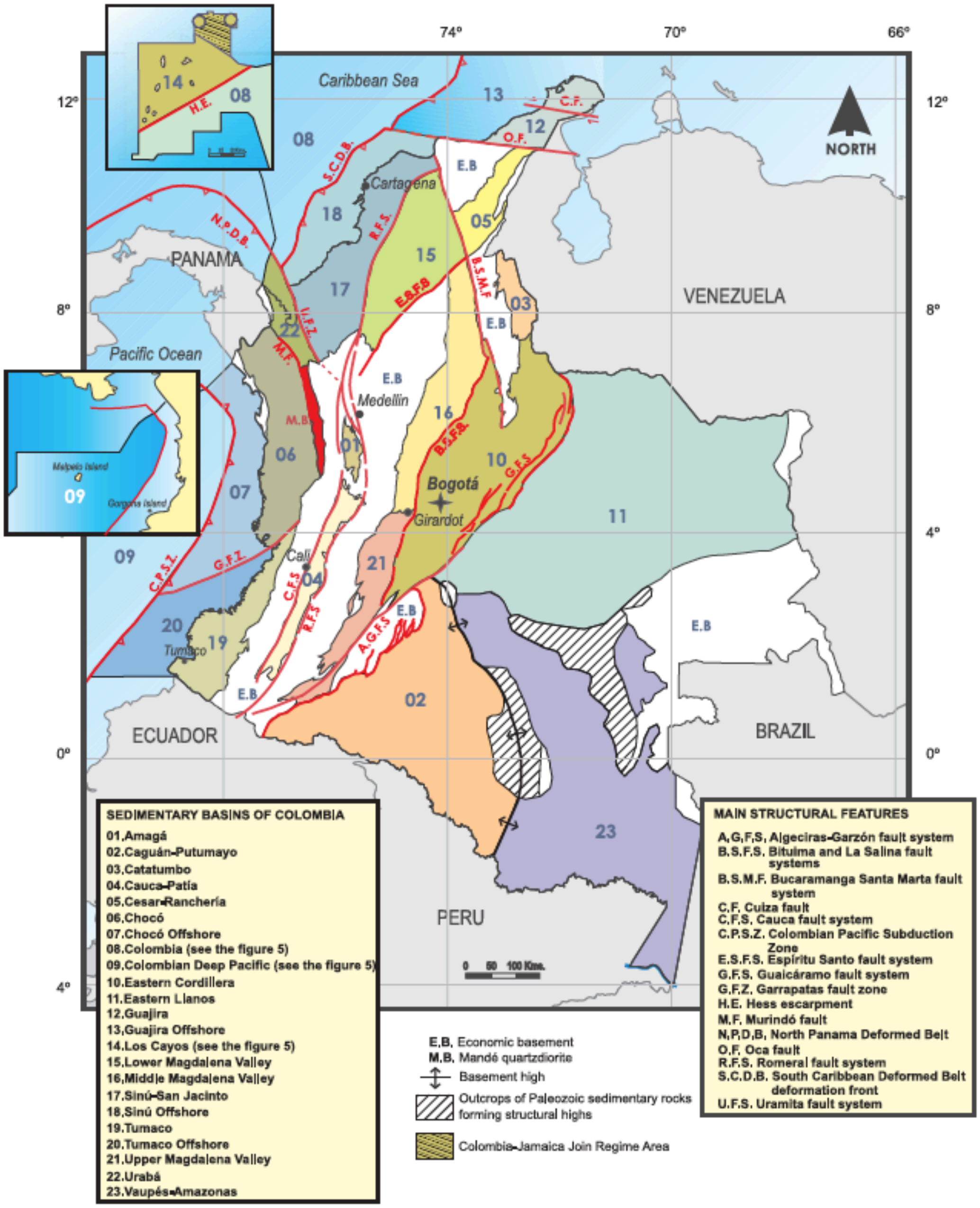

Figure 8. Colombian Sedimentary Basins. Source: Barrero et al., 2007.

Colombian Shale Formations

The Northern South America Region: Basins and Formations

The Northern South America region defined by ARI in its 2013 report on World Shale provinces comprises two countries: Colombia and Venezuela. Based on the different studies ARI performed, they determined that this region has the potential to produce shale gas and shale oil within marine-deposited Cretaceous shale formations in three main different basins: "the Middle Magdalena Valley and Llanos basins in Colombia, and the Maracaibo/Catatumbo basins of Venezuela and Colombia (figure 9). The shale formations within these basins (La Luna, Capacho, and Gacheta) have been responsible for sourcing much of the conventional oil and gas produced in their respective countries. According to the results of stratigraphic wells drilled in the basins, and information from geological surveys, it is believed that they "are similar in age to the Eagle Ford and Niobrara shale plays present in the United States of America" (Kuuskraa, Stevens and Moodhe, 187).

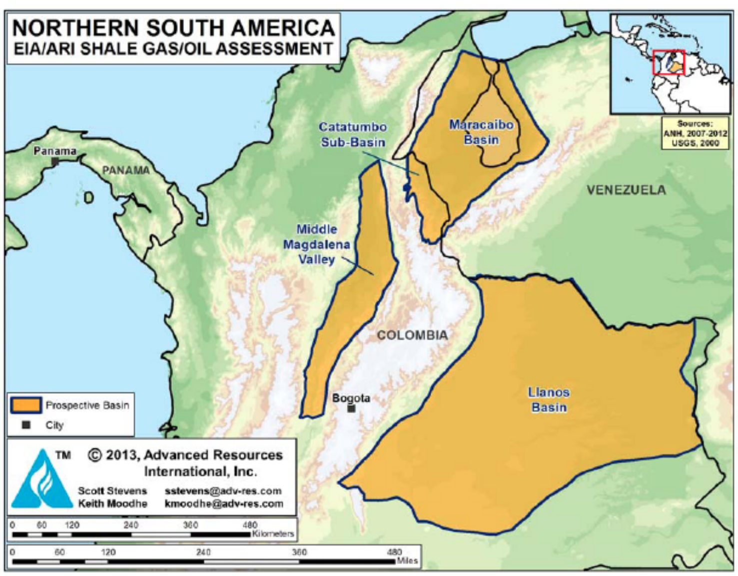

Figure 9. Northern South America Shale Basins. Source: Kuuskraa, Stevens and Moodhe, 187.

Up to now, the **Middle Magdalena Valley Basin (MMVB)** in Colombia has been the focus of shale exploration leasing and drilling activities in the region. Historically, this basin has been an important source for the conventional onshore production of hydrocarbons. "It contains thick deposits of the organic-rich Cretaceous La Luna Formation", with the presence of mostly oil to wet gas windows (Kuuskraa, Stevens and Moodhe, 190). The **Llanos Basin** is the largest basin in Colombia and in the region. Equivalent in age to the Cretaceous La Luna Formation, the Gacheta Formation is the main source rock present in the basin. However, its TOC and Ro measures tend to be lower than the ones of La Luna and of other successful shale plays. Nevertheless, earlier stratigraphic information shows that the western part of the basin could have richer organic concentrations and be more thermally mature. The **Maracaibo/Catatumbo Basin** present in Venezuela and Colombia is considered one of South America's richest petroleum basins based due to the amount of conventional resources it has produced in the past. The La Luna shale Formation is found throughout the Maracaibo (Venezuela) and Catatumbo (Colombia) basins, indicating a larger probability of finding shale oil and gas in it (Kuuskraa, Stevens and Moodhe, 190).

Of the three main basins of the region, only the Middle Magdalena Valley basin has undergone drilling activities to determine the prospectivity of shale resources (Kuuskraa, Stevens and Moodhe 188,194-196). However, given the geologic history of the Llanos and Maracaibo/Catatumbo basins derived from conventional drilling and production activities it is believed that they have good shale oil and gas potential.

In addition to those three, Colombia has a few other basins that are thought to contain potential shale formations, these include: First, the **Caguan-Putamayo Basin** in the south, which contains organic-rich Cretaceous shales in the Macarena Group. Based on information from PetroNova Corporation, who holds working interest contracts with the ANH in the basin, The Macarena Group shales, are shallower than the other shale formations present in Colombia (3,000 ft), but will tend to deepen towards the center of the basin where it is also less faulted (PetroNova, 2012). Second, the **Eastern Cordillera Basin,** which is located in the center of Colombia between the Eastern and Western foothills of the Eastern Cordillera. This Basin also contains organic-rich shales in the Chipaque Formation, of Turonian - Coniacian ages. However, the TOC is not as high as in the other Colombian shales formations (1-5%). Based on the thermal maturity and organic matter type, this formation would tend predominantly to produce Type II and Type II-III hydrocarbons. Finally, the **Cesar-Rancheria Basin**, located north of the Middle Magdalena and Catatumbo basins. Here the presence of the La Luna Formation is predominant, however it tends to be at shallower depths (1500 ft. to 4000 ft.) than in the Middle Magdalena and Catatumbo basins. The average TOC is 3%, and given its premature thermal condition it is believed that it will hold only shale gas (Escobar, 2013).

Colombian Basins

Middle Magdalena Valley Basin

Introduction and Geologic Setting

With approximately 13,000 mi^2, the Middle Magdalena Valley Basin (MMVB) is a north-south trending intermontane basin located between the Eastern and Central cordilleras of Colombia (figure 10). It is the basin that has produced most of the oil and gas in Colombia with over 40 discovered conventional oil fields, sourced out of Tertiary sandstone reservoirs. In spite of the fact that the MMVB is located within the Andes Mountain region, which is recognized to have complex tectonics including numerous thrust and extensional faults, the MMVB has a simpler and widespread structure and a relatively flat surface topography compared to the rest of the region. However towards the west its structure becomes more complex and overthrusted (Kuuskraa, Stevens and Moodhe, 192).

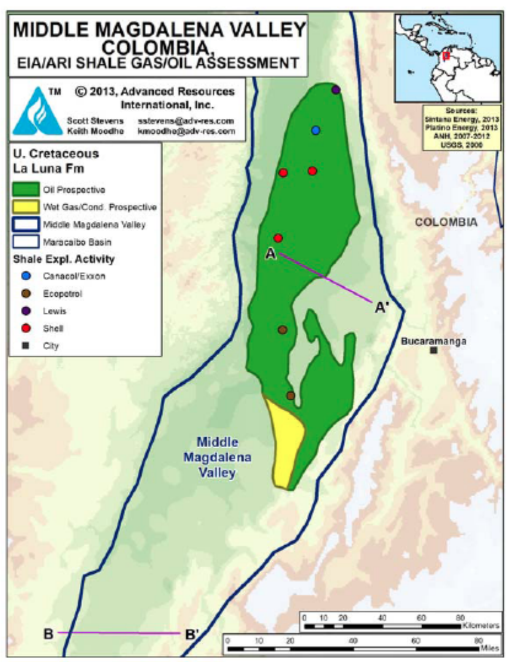

Figure 10: Middle Magdalena Valley Basin, Shale-Prospective Areas and Shale Exploration. Source: Kuuskraa, Stevens and Moodhe, 192.

The organic-rich Cretaceous La Luna Formation is the principal source rock in the MMVB. Based on the analysis of its facies, the depositional environment is believed to be "shallow marine, middle to outer shelf, in a transgressing sea". As defined by Torres et al. the La Luna Formation is a "calcareous shale and limestone, black in color, with high foraminifera content and limestone concretions". It is subdivided into three strata regions: the Salada, the Pujamana, and the Galembo. The first one is the most organic-rich with a TOC in the ranges of 4-12% and an average thickness of 490 feet. The Pujamana and the Galembo both have lower TOC's. The Galembo has the higher organic concentrations of the two, averaging 1-4% TOC and averages 750 ft in thickness. Initial maturity studies indicate that the Salada and Galembo members have reached the dry gas window for hydrocarbon generation (Torres et al., 2012). Underlying them, the 480 to 920 ft. thick Lower Cretaceous Tablazo/Rosablanca Formation is the next most important source rock in the MMVB. It is an organic-rich shale with TOC's ranging from 2 to 8%, and its thermal maturity indicates that it is in the oil to wet gas windows (Ro 0.6% to 1.2%) (Kuuskraa, Stevens and Moodhe, 193). The combination of these two formations, coupled with the different conventional formations present within the basin, makes it one of the most attractive areas for shale explorers, as it is a perfect hybrid basin (conventional and unconventional oil and gas formations) almost like the Bakken shale in the U.S.

Based on Schematic Cross-Section information publicly disclosed by Sintana Energy (one of the first companies in Colombia that showed interest in the exploration and production of shale resources), Colombia's Middle Magdalena Valley Basin correlates with Eagle Ford Shale formations, as it presents Upper Cretaceous (Umir and La Luna Shale Formation) and Lower Cretaceous shales (Simiti Shale Formation) with a total thicknesses of about 750 to 1,000 ft. (Sintana Energy, 2012).

Reservoir Properties (Prospective Area)

Based on available public information, ARI has estimated the reservoir properties of the MMVB to be as follows (table 1):

Table 1. Reservoir Properties of Middle Magdalena Valley Basin.

Basic Data	**Basin/Gross Area**		**Middle Magdalena Valley (13,000 mi2)**	
	Shale Formation		**La Luna/Tablazo**	
	Geologic Age		**Upper Cretaceous**	
	Depositional Environment		**Marine**	
Physical Extent	**Prospective Area (mi2)**		2,390	200
	Thickness (ft)	**Organically Rich**	1,000	1,000
		Net	300	300
	Depth (ft)	**Interval**	3,300 - 16,400	3,300 - 10,000
		Average	10,000	8,000
Reservoir Properties	**Reservoir Pressure**		Highly Overpress.	Highly Overpress.
	Average TOC (wt. %)		5.00%	5.00%
	Thermal Maturity (% Ro)		0.85%	1.15%
	Clay Content		Low	Low

Source: Modified from Kuuskraa, Stevens and Moodhe, 189.

As described in the previous table, the prospective area for the MMVB is approximately 2,600 mi^2 (20% of the gross area of the basin). Out of those the most important area corresponds to the 2,390 mi^2 of the Upper Cretaceous La Luna Formation. La Luna Formation is an organic rich shale (TOC 5%), with a lower thermal maturity ranging from 0.85% to 1.15% making the production of oil, condensate and wet gas a possibility Its thickness averages 1000 ft. and its depth ranges from 3,000 to 16,400 ft. (Kuuskraa, Stevens and Moodhe, 189,194)

Resource Assessment

Based on the shale gas and shale oil resource assessment methodology followed by ARI (Kuuskraa, Stevens and Moodhe, 27-44), their assessment for the MMVB leads to two key assessment values for shale oil and gas resources. First, risked, technically recoverable shale gas in the Basin is estimated to be 18.3 Trillion cubic feet (Tcf), out of the 135 Tcf of risked shale gas in place (GIP). Second, risked, technically recoverable shale oil in the Basin is estimated to be 4.7 billion barrels (B bbl), out of the 79 B bbl of risked shale oil in place (OIP) (table 2) (Kuuskraa, Stevens and Moodhe, 189).

Table 2. Resource Assessment for the Middle Magdalena Valley Basin.

Basic Data	**Basin/Gross Area**	**Middle Magdalena Valley (13,000 mi2)**	
	Shale Formation	**La Luna/Tablazo**	
	Geologic Age	**Upper Cretaceous**	
	Depositional Environment	**Marine**	
Gas Resources	**Gas Phase**	Assoc. Gas	Wet Gas
	GIP Concentration (Bcf/mi2)	88	150.3
	Risked GIP (Tcf)	117.8	16.8
	Risked Recoverable (Tcf)	**14.1**	**4.2**
Oil Resources	**Oil Phase**	Oil	Condensate
	OIP Concentration (MMbbl/mi2)	57	26.1
	Risked OIP (B bbl)	76.3	2.9
	Risked Recoverable (B bbl)	**4.58**	**0.18**

Source: Modified from Kuuskraa, Stevens and Moodhe, 189.

Llanos Basin

Introduction and Geologic Setting

The Llanos Basin is located in the eastern part of Colombia, and it is the largest basin in the country with an extent of 84,000 mi^2. While it has been extensively studied and drilled for conventional reservoirs, it has just recently become a focus of shale exploration. The main shale source rock identified in the basin is the Gacheta Formation, which is equivalent in age to the La Luna Fm in the MMVB and Maracaibo/Catatumbo Basins. Additionally to Gacheta, there are three more potential shale source rocks in the basin, those are: Los Cuervos Formation, of Cretaceous age as well, and Carbonera and Leon Formations, which are Tertiary shales (Kuuskraa, Stevens and Moodhe, 197-198; Sintana, 2013).

Reservoir Properties (Prospective Area)

The prospective area and reservoir in the Llanos Basin comprises mostly its principal and most important source rock, the Gacheta Formation. Its thickness averages 600 ft, and its depth ranges from 2000 ft in the east, up to 15,000 ft on the west margin of the basin. Out of the 84,000mi^2 that compromises the Llanos basin, only 1,820 mi^2 had been recognized as being prospective for shale based on its properties. The reservoir is believed to be entirely in the oil-window, however with an Ro that ranges from 0.3% in the eastern part to 1.1% in the western part of the basin, it is possible that condensate and wet gas could also be present. The net-source rock thickness of the formation averages 210 feet, but it ranges from 150 to 300 ft; the TOC values ranges from 1 to 3% with Type II and III kerogens present. Porosity is uncertain but believed to be relatively high (7%), from correlating it to La Luna Formation. Finally, the basin is marginally over-pressured, with an average of 0.5 psi/ft gradient (Kuuskraa, Stevens and Moodhe, 198).

Resource Assessment

ARI shale assessment for the Llanos Basin determined the two following key values for shale oil and gas resources for this area. First, risked, technically recoverable shale gas in the Basin is estimated to be 1.8 Trillion cubic feet (Tcf), out of the 18.2 Tcf of risked shale gas in place (GIP). Second, risked, technically recoverable shale oil in the Basin is estimated to be 0.63 billion barrels (B bbl), out of the 12.6 B bbl of risked shale oil in place (OIP) (table 3) (Kuuskraa, Stevens and Moodhe, 189). These results are driven by the small prospective area (1,820 mi^2) that is thought to be profitable. This fact is interesting considering how big (84,000 mi^2) and important is the Basin in the production of conventional oil and gas (Barrero et al, 2007) and also given that the world famous Orinoco Belt runs through it, where many giant fields for light and heavy oil have been discovered (Pacific Rubiales, 2013). The importance that this Basin could have in the future will depend heavily on more exploration coupled with extensive reservoir information obtained from seismic and drilling of stratigraphic wells.

Table 3. Resource Assessment for the Llanos Basin.

Basic Data	**Basin/Gross Area**	**Llanos (84,000 mi2)**
	Shale Formation	**Gacheta**
	Geologic Age	**U. Cretaceous**
	Depositional Environment	**Marine**
Physical Extent	**Prospective Area (mi2)**	1,820
Gas Resources	**Gas Phase**	Assoc. Gas
	GIP Concentration (Bcf/mi2)	40.4
	Risked GIP (Tcf)	18.2
	Risked Recoverable (Tcf)	1.8
Oil Resources	**Oil Phase**	Oil
	OIP Concentration (MMbbl/mi2)	28
	Risked OIP (B bbl)	12.6
	Risked Recoverable (B bbl)	0.63

Source: Modified from Kuuskraa, Stevens and Moodhe, 189.

Maracaibo-Catatumbo Basin (Venezuela, Colombia)

Introduction and Geologic Setting

The Maracaibo-Catatumbo Basin covers approximately 23,000 mi^2 in the northwest of Venezuela and northeast of Colombia (figure 11). Colombia's area is defined as the Catatumbo Basin by the Colombian Authorities, and it has been one of the most prosperous basins in Colombia, having many distinct conventional oil fields. The Maracaibo-Catatumbo Basin contains organic-rich marine-deposited Cretaceous shales. La Luna and Capacho Formation are the prospective shale formations that could contain hydrocarbons in the basin (Kuuskraa, Stevens and Moodhe, 199).

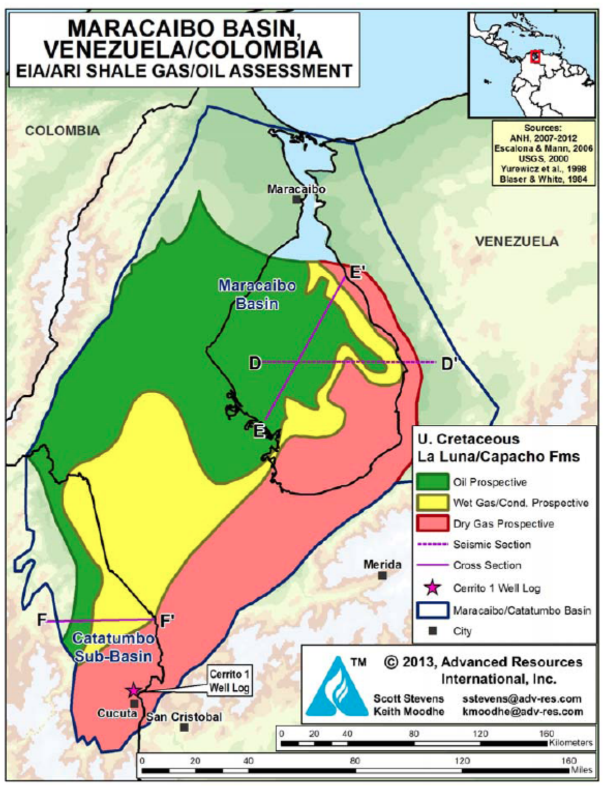

Figure 11. Maracaibo-Catatumbo Basin, Shale-Prospective Areas and Shale Exploration. Source: Kuuskraa, Stevens and Moodhe, 199.

Reservoir Properties (Prospective Area)

According to ARI, The Maracaibo-Catatumbo Basin hosts some of the world's richest source rocks and conventional oil and gas reservoirs. The primary source rock in the Basin is the Late Cretaceous La Luna Formation, which is the main formation in VMMB and it is widely believed to be of the same age as the Eagle Ford Shale Formation (Kuuskraa, Stevens and Moodhe, 203).

Within the much smaller Catatumbo Basin of Colombia, two formations are present and they could be responsible for the production of hydrocarbons. The most important one is the La Luna Formation. In the basin, La Luna Formation is about 200 ft thick; it is relatively shallow, compared to how it is developed in the Maracaibo Basin, ranging from 6,000 to 7,600 ft. Additionally, its TOC averages 4.5%, with Type II and III kerogens present. Finally, the thermal maturity ranges from 0.85 to 1.21% Ro (Kuuskraa, Stevens and Moodhe, 203). The next most important formation in the basin is the Capacho Formation. Its depth within the Catatumbo Basin, ranges from 6,500 ft. to 8,500 ft. The TOC can reach up to 5%, but normally it is about 1.5%, with Type II and III kerogens present. Lastly, its thermal maturity ranges from 0.96% Ro to 1.24% Ro (Kuuskraa, Stevens and Moodhe, 205).

Based on the previous information, the Catatumbo Basin has the potential of producing oil, wet gas and dry gas (figure 11). However, samples from wells drilled in the past in the southeast portion of the Basin indicate that the area could produce oil, as the Ro of the samples averaged 0.85% (Kuuskraa, Stevens and Moodhe, 203). Thus, as with the other Formations in the other Basins, more information from stratigraphic wells and cores will lead to more accurate definition of the *limits* of the prospective windows and their real potential.

Resource Assessment

For the Catumbo Basin, ARI defined the risked and risked-technically recoverable shale gas and oil resources as they did for the other basins. However, given the strongly differentiated hydrocarbons windows present in the basin, they divided those resources for shale gas and oil by windows. Unfortunately, ARI did not differentiate this basin by Formation, like they have done for the other Colombian Basins. Thus, figures for only the Catatumbo Formation are not available for this Thesis. However, the reader could create a fair picture by interpolating the total data from table 4, which summarize their findings, with the map presented on figure 11 (Kuuskraa, Stevens and Moodhe, 206). Finally, as stated before, more information from exploration will produce a more accurate assessment, which, ultimately will determine if the majority of resources are still in place, or if they have migrated through the heavy faulting of the basin to the conventional reservoirs or towards the Venezuelan Maracaibo Basin.

Table 4. Resource Assessment for the Three Hydrocarbon Windows within the Maracaibo/Catatumbo Basin.

Basic Data	**Maracaibo/Catatumbo (23,000 mi2)**		
	La Luna/Capacho		
	Upper Cretaceous		
	Marine		
Physical Extent	7,280	4,290	5,840
Gas Resources	Assoc. Gas	Wet Gas	Dry Gas
	71.8	176.1	255.7
	183	264.4	522.6
	18.3	52.9	130.7

Oil Resources	Oil	Condensate	
	92.3	41	
	235.1	61.6	
	11.75	3.08	

Source: Modified from Kuuskraa, Stevens and Moodhe, 189.

CHAPTER 3. COLOMBIA'S PETROLEUM FISCAL REGIME

Petroleum Fiscal Regimes Framework

INTRODUCTION

Within the extractive industries (mining and oil and gas) the relationships between sovereign governments and corporations are governed principally by the fiscal terms established by the host countries. The fiscal terms essentially determine the financial benefits and risk allocation for each party. These terms can apply to all extractive projects by being incorporated within the law of the country, or could be specific to a type of industry or project by being exclusively described within a contract between the parties. According to the Revenue Watch Institute, the fiscal terms in the extractive industries must be based on four intrinsic characteristics of those industries. First, the resources to be exploit are finite, thus governments should be paid for the depletion of their assets; second, extractive projects are intense in capital and require major upfront investments before the companies receive any revenues; third, extractive projects entail many different risks for the companies; and finally, extractive revenues can represent a big percentage of a government revenue, which if not well managed could result in the appearance of the Dutch disease (Revenue Watch Institute, 2013).

However, when fiscal terms are managed successfully, extractive projects can generate large and continuous streams of revenue to the sovereign country. The right balance in the fiscal terms will attract foreign investment and will also produce good levels of revenue for the country. On the contrary, a fiscal regime favoring the government, will fail to attract companies to invest as the projects will not be economically attractive to them, thus resulting in small revenue levels for the government. Likewise, a fiscal regime favoring private corporations can create discomfort within the country population, given the perception that they are not being well compensated for the depletion of their assets (Revenue Watch Institute, 2013).

TYPES OF FISCAL REGIMES

There are mainly two categories of Petroleum Fiscal Regimes (PFRs): *concessionary* and *contractual based* systems. The primary differences between them reside in determining "where, when, and if ownership of the hydrocarbons transfers to the International Oil Company (IOC)". More differences between these two systems and a third less common type of contractual based system –the *Service Agreement*– are explained in detail in table 5. Furthermore, when thoroughly analyzed, one can conclude that Petroleum Fiscal Regimes within the same category can vary widely as each country makes unique adjustments for their benefit. Nevertheless, the mechanics to determine government and corporate take, risk allocation and hydrocarbons entitlement within a category are basically the same (Macartan, Sachs, and Stiglitz, 55-57).

Table 5. Comparison of Fiscal Systems

	Royalty/Tax Systems	Production-Sharing Contracts	Service Agreements
Global frequency (% of systems)	44%	48%	8%
Type of projects	All types: exploration, development, EOR	All types: exploration, development, EOR	All types but often non-exploration
Ownership of facilities	IOC	Government NOC	Government NOC
Facilities title transfer	No transfer	"When landed" or upon commissioning	"When landed" or upon commissioning
IOC ownership of hydrocarbons (lifting entitlement)	Gross production less royalty oil	Cost oil + profit oil	None
Hydrocarbon title transfer	At the wellhead	Delivery point, fiscalization point or export point	None
Financial obligation	Contractor 100%	Contractor 100%	Contractor 100%
Government participation	Yes but not common	Yes, common	Yes, very common
Cost recovery limit	No	Usually	Sometimes
Government control	Low typically	High	High
IOC lifting entitlement	Typically around 90%	Usually 50–60%	None (by definition)
IOC control	High	Low to moderate	Low

EOR, enhanced oil recovery; IOC, international oil company; NOC, national oil company.

Source: International Petroleum Fiscal Systems Data Base, © 2001 Daniel Johnston. Tulsa: PennWell.

Source: Macartan Humphreys, Jeffrey Sachs, and Joseph E. Stiglitz; *Escaping the Resource Curse* (New York: Columbia University Press, 2007) 67; Print.

Concessionary or Royalty/Tax Systems

Concessionary systems, commonly known today as royalty/tax systems, describe the relationship in which the host government grants the private company (National Oil Company –NOC– or IOC) the control of a fixed area for a specific amount of time to perform exploration and production activities. In return, the government will impose some royalties and taxes over the production as a compensation for the depletion of their reserves (Johnston, 1994).

Johnston determined that the following features characterize Royalty/Tax systems. First, the oil companies (NOC and IOCs) engage in a contract with the host government to initially explore for hydrocarbons at their own risk. Then, if a discovery is believed to be commercial, the oil company has the right to develop and produce the hydrocarbons found. Latter on, when hydrocarbons are produced the oil company will take title to its share—gross production less the royalty—at the wellhead. Additionally, differences on how the royalty is paid (money or oil), will determine the 'lift' percentage of production of the company. Furthermore, the IOC owns the exploration and production equipment; and finally, the IOCs pay taxes on profits from the sale of the oil (Macartan, Sachs, and Stiglitz, 58-59)

Production Sharing Contracts Systems

Contractual based systems, categorize the relationship in which the IOC will work for the host government on a contractual basis and in return will get paid for their services either in oil or in money. These systems can be further divided into *Production Sharing Contracts* (PSCs) and *Service Agreements* (SAs) (Johnston, 1994).

The following features characterize PSCs. Like in the royalty/tax system, oil companies will engage in a contract with the host government to explore for hydrocarbons at their own risk. However, in the PSC, if a discovery is made the host government will decide whether to produce it or not. If so, the oil company will assume all the costs for providing the production equipment. From the production, the contractor can recover its expenses but to a certain limit determined in the contract. Further, in PSCs the entitlement of the oil from the host government to the IOC takes places at the export point. There the contractor takes title of cost and profit oil. Additionally, the title of the production facilities and equipment will be transfer from the IOC to the host government, according to the contract. Finally, it is common for the host government to pay the taxes of the IOC (Macartan, Sachs, and Stiglitz, 60-61).

Service Agreements (SAs) as PSCs are based on the fact that the host government will contract a company to produce the hydrocarbons. However, and this is probably one of the most important differences between them, the contractor is paid a cash fee for their services. Thus, this determines that all the production belongs to the state and that there is no entitlement of the hydrocarbons to the contractor in the SA agreement. Like in PSCs, the contractor is responsible for providing all the capital associated with exploration and development, however it will recover its costs through the sale of the hydrocarbons plus a fee. Additionally this fee is often taxable, which differs to the PSC taxes scheme (Macartan, Sachs, and Stiglitz, 62).

Main Fiscal Instruments

There are different fiscal instruments used within the PFRs that allow the host government to increase their revenue stream from the petroleum operations held within their countries. According to the Revenue Watch Institute among the most common ones that states use in varying combinations are:

- *Bonuses*. These are payments (one-time or several) based on the signing or finalization of the contract, or the achievement of certain exploration or production goals, which are determined by law or the contract.
- *Royalties and Production Sharing*. As explained before, these are the payments made to the government to compensate for the depletion of their non-renewable resources.

- *Income Tax.* Governments will rule whether the IOC will pay general corporate income tax rates like the other businesses in the country or whether they will pay different (normally higher) tax rates. Additionally, governments will determine the rules on how their tax system handles costs and deductions, which will impact profoundly the commerciality of a project.
- *Windfall Profits Taxes.* These are additional tax payments that governments set up to gain a greater share of the project surpluses. These can be indexed to prices or profits that the government believes exceed the levels necessary to attract investment.
- *Other Taxes and Fees.* Additional sources of fiscal revenues for the government include withholding tax on dividends and payments made overseas, excise taxes, customs duties, and land rental fees (Revenue Watch Institute, 2013).

Colombia's Fiscal Regime

INTRODUCTION

By the early 1990s participation of the private sector in the oil and gas industry within most of the producing countries of Latin America was limited or null. If granted, it was through the use of PSCs where IOCs would associate with the NOC of the country. However, as the decade progressed, most of the countries introduced policy or legal reforms to allow more participation from the private sector. Eventually this led to three main trends over the region. First, some countries (Bolivia, Argentina, and Peru) dismantled or sold their NOCs. Second, Brazil and Colombia kept their NOCs but created new agencies to handle the administration of the hydrocarbon contracts; also they opened their markets for private investors and allow IOCs to work alone or in association with their NOCs within their territories. All those countries were able to make these transitions by switching from PSCs to Royalty/Tax regimes. The last trend, followed by Ecuador and Venezuela was to maintain their PSCs fiscal regime, but allow more participation of the private sector (Valera, 2007).

AGENCIA NACIONAL DE HIDROCARBUROS (ANH)

Established by the Decree 1760 of 2003 of Colombia, the Agencia Nacional de Hidrocarburos (ANH) was created "as a response to the critical situation that Colombia was undergoing, due to decreasing petroleum reserves, which would eventually take the country into becoming a crude oil importer". Until that year, IOCs could only operate in Colombia through PSCs with the Colombian NOC (Ecopetrol). The creation of the ANH marked the restructuring of the hydrocarbons sector of Colombia. First, it determined the transition of Colombia from a PSC system to a Royalty/Tax system. Second, it established the new role of Ecopetrol. Since 2003, the NOC became purely an E&P company, leaving to the ANH the role of regulatory and administrative entity of the hydrocarbons sector. Finally, the ANH became the administrator of the revenues from the petroleum contracts (royalties, taxes, and profit oil from PSCs already in-place) (ANH, 2013).

As part of the strategy to create an environment where IOCs were willing to go and invest in Colombia, the ANH established two new types of contracts to be used under the royalty/tax system. The first one, the E&P contract, was created fundamentally for the agreements between the ANH and IOCs or Ecopetrol for areas that were recognized to be geologically feasible. This contract contemplates three different and separate periods: Exploration, evaluation and production, with a total duration of approximately 33 years for the three periods. The second contract type is the Technical Evaluation Agreement (TEA), which was designed to help the ANH acquire more technical information (geological, petrophysical, and stratigraphic) of areas that have not been studied in detail in the past, in order to determine the presence of hydrocarbons. The duration of these contracts is up to 18 months. If hydrocarbons are discovered, the TEA contractor will have the first option to sign an E&P contract with the ANH (ANH, 2013).

Up to 2013, the ANH has proved valuable to the Colombian government and its people. Starting in 2005 the ANH has consistently signed E&P and TEA contracts (figure 12). As a result of the signing of these contracts, oil and gas reserves have improved considerably since then. This fact also reflects the emphasis from the ANH to acquire more data to support their geological analysis when they attempt to sell the blocks in bidding rounds. Using the TEA agreements and the *minimum exploration programs* that companies must perform in the E&P contracts, the ANH has been able to consistently grow the total kilometers of seismic acquisition (figure 13) and the number of exploratory wells (figure 14). This additional information about basins, plays and reserves has helped attracting more IOC's to Colombia, including companies like Conoco Phillips, Shell, Exxon Mobil, among other big players (ANH 2013). Furthermore, the new fiscal regime and contract models from the ANH, coupled with the perception of a more secure Colombia within this period (2005-2013), have proven to be effective tools to attract new foreign investment (figure 15).

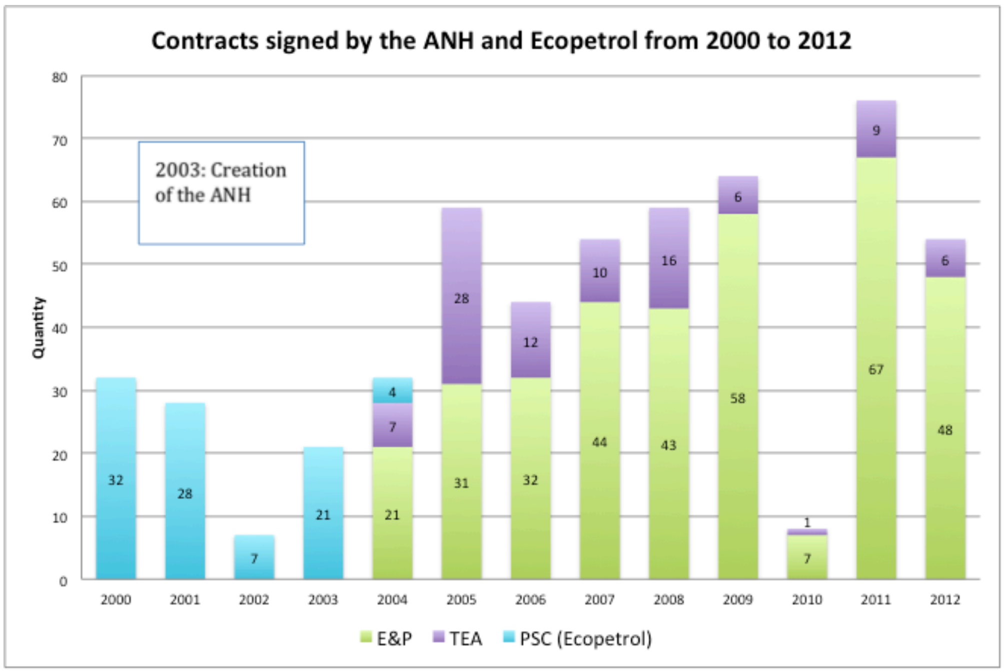

Figure 12. Contracts signed by the ANH and Ecopetrol from 2000 to 2012; from ANH, 2013.

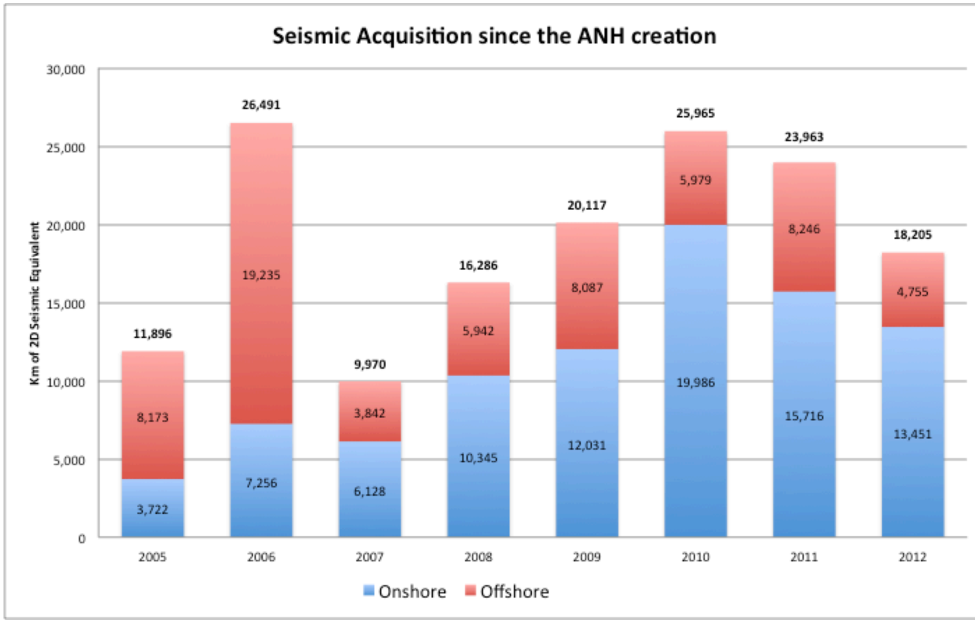

Figure 13. Seismic acquisition since the creation of the ANH, from ANH, 2013.

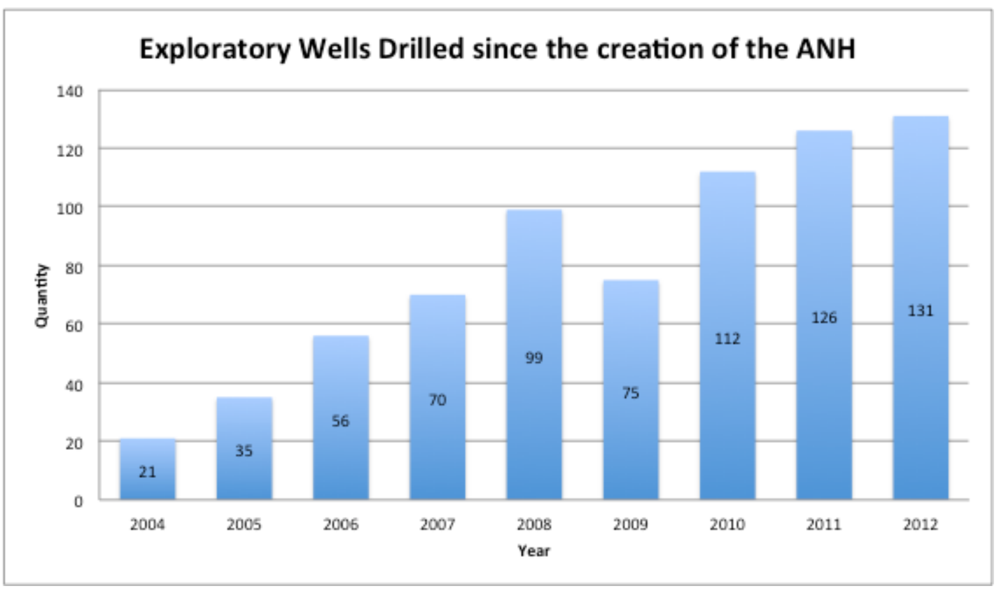

Figure 14. Exploratory wells drilled since the creation of the ANH, from ANH, 2013.

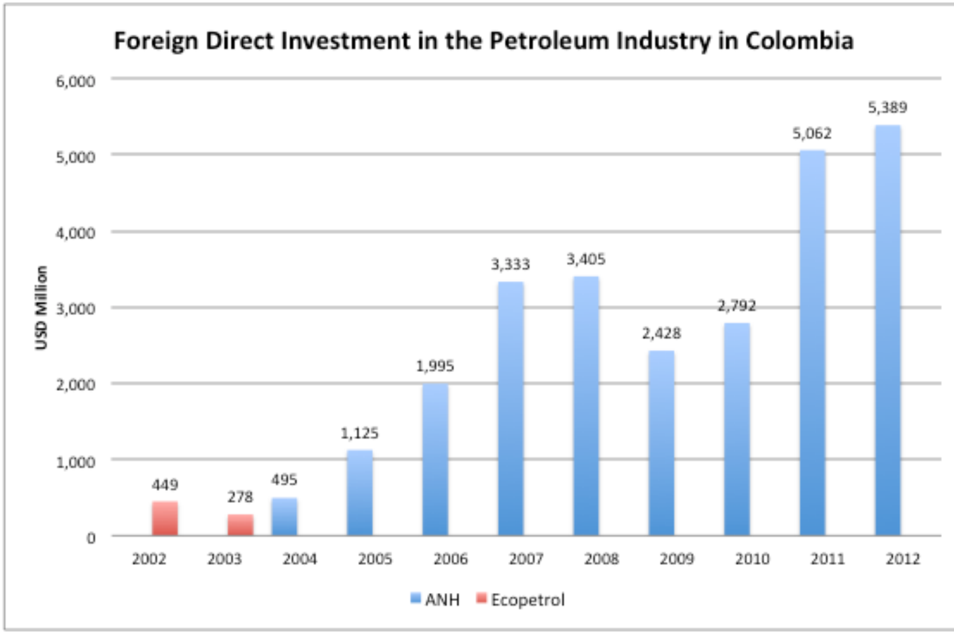

Figure 15. Foreign direct investment in the petroleum industry in Colombia, from *Foreign Direct Investment*. 2013.

Remarks of the Fiscal Regime of Colombia

According to the study from the consulting firm Arthur D. Little, Colombia has one of the must competitive fiscal terms and contracts in Latin America (Lafaurie Taboada, 2012). This statement has been verified by the increased foreign investment and activity described in previously. In order to understand why it is considered one of the most competitive fiscal terms, following will be present an analysis of the most important points of the fiscal regime of Colombia, based on the information found principally in the following documents: first, the *Terms of Reference* provided to the oil companies for the last bidding round process from the ANH -Ronda Colombia 2012-; and second, the *contract* minutes published also as part of the documents governing the Ronda Colombia 2012 bid process. These two documents incorporate within them all the laws and concepts that apply to the Colombia's Fiscal regime. Before going into the analysis of those two documents to highlight the most important concepts of the fiscal regime of Colombia, it is important to point out the most critical government regulations that an oil company interested in participate in Colombia must understand as they govern the fiscal regime of the country. These regulations are:

- Decree-Law 1760 of 2003;
- Decree-Law 4137 of 2011;
- Agreement No. 04 of May 4, 2012;
- Agreement No. 02 of February 16, 2012;
- Article 76 of Law 80 of 1993,
- Article 13 of Law 1150 of 2007;
- Law 1474 of 2011;
- Resolution No. 18 1495 of September 2, 2009;
- Resolution No. 18 0742 of May 16, 2012.

Two types of Contracts

As previously described, the ANH has established two types of contracts that can be signed between them and an oil company: The Exploration and Production (E&P) contract, and the Technical Evaluation Agreement (TEA). The purpose of the E&P contract is to grant the contractor (IOC, Ecopetrol or Joint Venture between those two) the exclusive right to undertake and carry out exploration activities in a given area and to produce the hydrocarbons discovered in it, assuming all the costs and risks. In exchange to these rights, the contractor will pay to the ANH fees for the ***Use of the Subsoil***, and/or of "***High Prices***"; also will pay cash as part of ***Share of Production***; additionally will recognize and transfer the ***Royalties*** in cash or in kind (oil and gas) to the ANH, and finally will make contributions for *Training, Institutional Strengthening and Technology Transfer*. Additionally, the E&P contract is divided in three specific periods in which the contractor will perform specific activities. These are: exploration, evaluation and production ("*Terminos de Referencia Definitivos - Adenda No. 4*").

The purpose of the TEA agreement is to grant the contractor the exclusive right to carry out technical evaluation studies in a specified area, aimed at determining prospectivity of hydrocarbons within the area. The contractor will perform the agreed *exploration program* at its sole cost and risk and will pay a fee for the ***Use of the Subsoil***. In case of a discovery, the contractor will have the right of first refusal to exercise a conversion of the contract from TEA to an E&P Contract with the ANH ("*Terminos de Referencia Definitivos - Adenda No. 4*").

Economic Rights

The *Economic Rights* are the fiscal instruments that the Colombian government uses to obtain revenue from the contractors that have signed petroleum contracts with the ANH. There are four main instruments, and depending on how they are established in the law and in the respective contracts they will be payable to the ANH in cash or in kind (oil and/or gas) (*"Terminos de Referencia Definitivos - Adenda No. 4*").

Fees for Use of the Subsoil

The *Fees for Use of the Subsoil* are periodic cash payments (monthly) to be made by the contractors, as compensation for the exclusive right to use the subsoil of the allocated area for evaluation, exploration and production under the contract. The amounts will vary depending on the *type of deposit, type of area, length of the contract,* and *type* *of contract* signed between the parties. All fees are collected in US dollars by the ANH ("*Terminos de Referencia Definitivos - Adenda No. 4*").

For the E&P contract, the way to calculate them is the following:

- In **Exploration Areas**, it corresponds to a fixed fee per surface unit of the area assigned to the contractor (figure 16) *("Minuta Contrato E&P*").
- In **Evaluation and Production Areas**, this fee corresponds to a fee per production unit belonging to the contractor. For the contracts awarded for the bidding round Ronda Colombia 2012, the fee is US $0.1255 per barrel or per thousand cubic feet (Mscf) of natural gas. This fee will be adjusted annually based on the variation of the last years Producers Price Index –PPI- of the United States ("*Minuta Contrato E&P*"*)*.

Monthly amount per phase in US$/hectares on exploration areas				
Size of contract area	First 100,000 hectares		Each hectare in addition to first 100,000	
Duration of the phase	<= 18 months	>18 months	< = 18 months	>18 months
Onshore	2.48	3.30	3.30	4.95
Offshore	0.82			

Figure 16. Use of subsoil fee calculation for Exploration areas, as determined in the bidding terms for the ANH Ronda Colombia 2012, from E&Y, 2013.

Fees on account of "High Prices"

The *Fees on account of "High Prices"* are a counter-measure from the ANH, trying to compensate for the fluctuation of the international prices of hydrocarbons. The amount and timing of those fees, either in kind or cash, are stipulated in the E&P Contract ("*Terminos de Referencia Definitivos - Adenda No. 4*").

For the Ronda Colombia 2012 bidding process, the E&P Contract established the following "High Prices" formula *("Minuta Contrato E&P")*:

$$Q = \left[\frac{(P - Po)}{P}\right] \times S$$

Where:

Q: Total amount of fees to be collected by the ANH for High Prices.

P: Price of the hydrocarbon. For oil, is the monthly average price of the West Texas Intermediate index (WTI) in dollars per barrel. For natural gas, is the monthly average sale price of the gas sold in the contract in US dollars per million British thermal units (BTU).

Po: is the base price of benchmark crude oil expressed in US dollars per barrel, and for natural gas, it is the average natural gas price in US dollars per million BTU, according to a table included in the contract.

S: Participation percentage, based on the following table (table 6).

Table 6. Participation percentage for determining High Prices Fees,

Price of WTI (P)	*Participation %*
Po ≤ P < 2Po	30%
2Po ≤ P < 3Po	35%
3Po ≤ P < 4Po	40%
4Po ≤ P < 5Po	45%
5Po ≤ P	50%

Source: "Minuta Contrato E&P".

Share of Production (X%)

The *Share of Production* fee is a percentage that the contractor agrees to pay to the ANH from the net production of the well, expressed in barrels of oil equivalent

(BOE). This percentage is offered by the contractor in the bidding process, and constitutes a differentiator in the awarding of the contracts. The percentage is a whole number equal to or greater than one ("*Terminos de Referencia Definitivos - Adenda No. 4*"*)*. Normally it tends to be between 5 and 10%, but there have been bids awarded with percentages as high as 34% (*"Informe de Elegibilidad Ronda Colombia 2012")*.

Royalties

Royalties account for the biggest payment from the contractor to the ANH. They represent the payment in exchange of the exploitation of the hydrocarbons that belong to the country. Colombia has what is referenced in the industry as an escalating royalty system. The royalties are calculated based on the monthly average field production of the field. For the case of oil production the calculation must be made based on the following table (figure 17).

Field daily production (monthly average in barrels of crude per day)	Percentage (%)
Up to 5,000	8
5,001 to 125,000	8 + (production – 5,000) * 0.10
125,001 to 400,000	20
400,001 to 600,000	20 + (production – 400,000) * 0.025
More than 600,000	25

Figure 17. Royalties calculation scheme as determined by the Law 756 of 2002 of Colombia, from E&Y, 2013.

To determine the royalties for gas fields, first a conversion factor is applied to determine the production of gas in BOE per day. Then, based on certain conditions of the field, a percentage is applied to the oil royalties scheme to determine the final values (figure 18):

Location	Percentage (%)
Onshore and offshore below 1,000 ft depth	80
Offshore more than 1,000 ft depth	60

Figure 18. Percentages to be applied to the oil royalties for gas production fields as determined by the Law 756 of 2002 of Colombia, from E&Y, 2013.

Periods of the Contract

There are three periods within the E&P Contract. These are the following:

1. **Exploration Period:** During this period the contractor will perform the *exploration program* to determine the prospectivity of hydrocarbons within the area awarded. This period can be divided in two (2) *phases* of three (3) years each *("Minuta Contrato E&P")*.
2. **Evaluation Period:** After a discovery is made, the contractor can request an evaluation period to determine the commerciality of the discovery. This period cannot exceed two (2) years if the contractor includes the drilling of exploratory wells, or one (1) year in any other case. By the end of the period the contractor must present an analysis to the ANH (known as declaration of commerciality), and decide whether it will produce the discovery or not *("Minuta Contrato E&P")*.
3. **Production Period:** It is the period of time in which a contractor will perform the *Production and Development activities*. In the case of conventional hydrocarbons the initial period is of 24 years counted from

the declaration of commerciality but this time can be extended until the economic limit of the field.

Type of Deposit

There are two types of deposits: conventional and unconventional. A contractor will be awarded in the signed contract, the exploration and production of a given type of deposit within the granted area. However, if during the period of exploration a contractor finds that within the area both types are present, it can request the exploration and production of both types of deposits (*"Terminos de Referencia Definitivos - Adenda No. 4"; "Minuta Contrato E&P")*.

NEW REGULATION FOR SHALE RESOURCES

Understanding the potential of unconventional resources in the country, the Ministry of Mines and Energy of Colombia issued two Resolutions that defined the framework for the exploration and production of unconventional resources in the country. The first one is the Resolution No. 18-1495 of 2009, which established the basis for a specific framework for these types of resources. The second one and latest is the Resolution No. 18-0742 of May 16, 2012. This resolution provided further definitions and procedures related to the exploration and production of hydrocarbons found in unconventional reservoirs ("*Resolucion No. 18 1495 de 2 de Septiembre de 2009*").

The next section provides an analysis of the most important points that these two resolutions have changed or defined regarding the exploration and production of unconventional reservoirs.

- The resolutions define specifically what should be understood in Colombia as an unconventional play that produces hydrocarbons. Additionally, provide all the definitions related to this type of resources.
- The Resolution No. 18-0742 provides a definition of *well arrangement* or *well pad*. This is important considering that it changes how royalties will be calculated for unconventional resources. This distinction however does not affect the economic analysis of a field.
- Likewise, Under the Resolution No. 18-0742, stratigraphic wells can be transformed latter onto producing wells. This is important considering that until this resolution stratigraphic wells were required to be abandoned after the geological information was acquired. With this resolution, operators of the field can use the stratigraphic wells latter on in their production plans and decrease their development costs.
- For unconventional resources, the resolutions established that the exploration period of the E&P contract is extended from 6 to 9 years, plus any extensions granted by the ANH based on the rules of the specific contract. Consequently, each phase of this period can last up to 3 years.
- Related to this point, Resolution No. 18-0742, establish that for unconventional resources the contractor must perform one core-sampling job for every three exploratory wells drilled within the exploration period. This demonstrates the interest of the Colombian government of acquiring more geological information about the basins for next contract bidding rounds. Further, while this could increase the costs of exploration, the core-sampling jobs could prove beneficial and provide the operator better information of the reservoir.

- Regarding the production period, when producing unconventional resources this period is extended from 24 to 30 years, plus any extensions granted until the economic limit of the field.

Likewise, the Decree 4923 of December 26 of 2011, made an adjustment for the calculation of royalties for unconventional resources. Since that day, when calculating the royalties for unconventional hydrocarbons, a **60%** must be applied to the table defined for oil royalties (figure 17).

Finally, the ANH's increased understanding of the behavior of the oil and gas prices in the international market and the economics of unconventional resources, established that when calculating the fees for 'Higher Prices' the *Po* to be used will be a fixed price of $81 per barrel.

CHAPTER 4. COLOMBIA'S RISK ANALYSIS

Background

Any company willing to acquire new reserves should evaluate all the risks associated with acquiring those reserves, and more importantly evaluate all the risks that producing those reserves will create to the company, because the big profits come from producing the reserves not only having them. Entering into a new oil field, whether it is in a new county, state or country will bring different risks that will affect whether the project is or not economically viable. From the risk analysis evaluation, a company can make two decisions: go for the new resources or step away from them. If the company decides to acquire the new resources, the evaluation of risk should be used to manage and reduce the risks they will face in the forthcoming operation.

Types of Risk

As Krishan Malik presented on his Petroleum Concessions and Agreements class at The University of Texas at Austin during the Spring of 2012, any company willing to operate in any country will face different risk that fall in two categories: Country and Petroleum risks. Within Country Risk there are three defined risk classes that correspond to the risks that are applicable only to the country. Those include: political, economical and commercial risks. On the other hand, Petroleum Risks are those that are unique to develop any type of oil and gas exploration and production activities. These can be further classified as exploration and production risks (Malik, 2012).

Analyzing the classification of the Country Risks, we can determine that within the *political risks* class, the risks that can normally be defined are war, external threats, civil labor unrest, terrorism and regime stability. While all of those should be carefully evaluated, probably the most important is the last one, because of its direct relationship to the profitability and financial analysis of a long-lived project. The *economic risks* are the same that are faced by any foreign investment in any type of industry. The risks identified in this class include: GDP Change, Inflation change, debt ratio of the country, budget deficit over GDP, balance of payments index and exchange ratio change. Finally, under the *commercial risk* group the common risks are: legal system stability, administrative constraints and finally repatriation restrictions. From this ones probably the most important one is the repatriation restrictions, as it will trigger other type of risks already covered like exchange ratio changes (Malik, 2012).

Likewise for the Petroleum Risks classes, the *exploration risk*s that could be faced by any operator entail the following: business prospects, data access, establishing operations, front-end entry costs, negotiation process and finally logistic requirements. Under the *production risks*, we can find: Work program stability, crude supply obligation, training costs and decision-making efficiency. (Malik, 2012).

These categories and their subcategories parallel the work of Gustavson, where he defines the risks related “to the expectation of the predicted cash flow”, which are essentially the Petroleum Risks from Malik’s classification; and, political risks, which relates to the Country risks classification and definition of Malik (Gustavson, 57-59). Furthermore, all of the risks defined and categorized by Malik, could be paired with the results of the study made by Ernst & Young in 2008 in which they identified the *Top 10 Risks for the Oil and Gas Industry*. However, this study does highlight some risks that are not part of Malik’s risks classification. These risks are: the human capital deficit, climate concerns and finally the energy conservation. These risk factors are becoming more and more important for the future of the industry, as they reflect current national and international anxieties suffered by operators of oil and gas fields (Jessen, 18-20).

Political, Economical and Commercial Risk Assessment of Colombia

Probably the major risks that Colombia presents to any company willing to acquire new oil and gas reserves in the country are within the *country risk* category. Within this category, a mix of different political and commercial risks will likely represent the major risk that an operator needs to evaluate and address when exploring for or producing oil and gas in Colombia.

TERRORISM

A company should evaluate terrorism by following the different definitions that the Federal Bureau of Investigation (FBI) has for it, specially the ones regarding “International terrorism” ("Definitions of Terrorism in the U.S. Code"). By doing so, a company will be able to evaluate other related activities that sometimes are not considered terrorism. Within these activities we can include extortion, kidnapping, sabotage, and to some extent any type of political violence. Terrorism is a complex risk to quantitatively estimate, as it does not follow any historic pattern and can be perceived by the victim as massive or miniscule (Hartwig, 2012). According to AON’s 2013 Terrorism & Political Violence Map (figure 19), Colombia has a high country risk for terrorism and political violence. The perils that Colombia can present are: “Terrorism and Sabotage, Strikes, Riots, Civil Commotion and Malicious Damage” (AON Group Inc, 2013). Within South America, Colombia is one of the four countries with high country risk along with Venezuela, Ecuador and Paraguay (AON Group Inc, 2013). It is important to consider when analyzing South America as a region -using the AON map for 2013- that the whole region is consider riskier relative to the previous assessment of 2011 (AON Group Inc, 2011). This increase in risk reflects the different political and economical events of the last two years that have resulted in riots, insecurity and terrorism acts within the countries that comprise the region. Additionally, in the case of Colombia, it is important to understand that even with the different strategies that the Colombian government has applied towards minimizing the perils identified by AON, the classification as a higher risk country persists. The result of the peace agreement with the Revolutionary Armed Forces of Colombia -Fuerzas Armadas Revolucionarias de Colombia in Spanish- (FARC) guerrilla group will likely lead to some changes in AON's risk ratings (Washington Office on Latin America (WOLA), 2013).

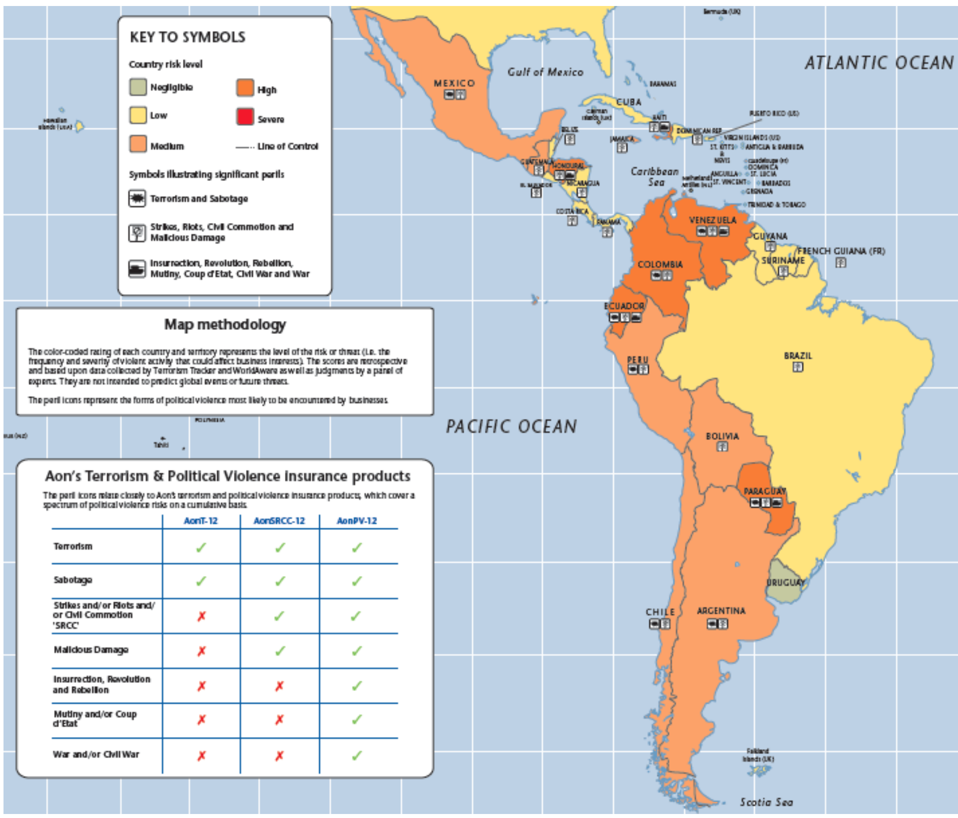

Figure 19. Snapshot of South America Terrorism & Political Violence Map from AON 2013 Terrorism & Political Violence Map; Source: AON, 2013

In the oil and gas industry in Colombia, terrorism has covered all the risks defined previously. Of those, common acts of sabotage and piracy have been quite notorious and common in the last 15 years. Colombia has suffered from common criminals and also terrorist groups stealing oil and gas from its pipelines. Apart from the direct financial consequences –loss of revenue for not selling the petroleum products - that those actions represent to operators and the Colombian government, these actions, normally crudely made, often end up in oil spills or gas explosions that cause environmental and financial damages. Examples for these types of actions are many (Sierra, 2013); if the reader will like some, a Google research of "*oil spill in Colombia*" will bring more than one million results. One that was quite notorious last year occurred in Barrancabermeja, the most important oil and gas city in Colombia. There, the criminals installed an illegal valve in a pipeline that malfunctioned and generated an environmental emergency as oil was contaminating water sources in the region and in Venezuela; thus it was starting to be also an international problem (El Espectador, 2012).

In addition to simple theft, Colombia also suffers from more *complex* terrorism actions within its territory against the oil and gas industry. It is believed that from those actions Colombia loses approximately US$1 Million dollars daily for attacks related to pipelines and oil and gas infrastructure. From January to June of 2012 the oil and gas infrastructure was attacked 67 times, which represented a spike from 2011 of 253% (El Tiempo, 2012). From January to September of 2013, Ecopetrol reported 147 attacks to oil and gas infrastructure of the country, thus making it one of the worst years for the industry, representing a growth of 17.6% from the same period the previous year (Sierra, 2013). Simultaneously, during 2012 Colombia's petroleum industry suffered one of the worst years in terms of kidnaps and murders as 14 engineers were kidnapped and 2 were killed. Terrorist groups like FARC and the National Liberation Army –Ejercito de Liberación Nacional in Spanish- (ELN) see extortion as a new method to obtain financial resources for their operations, as their finances have been hit hard by the war against drugs. Additionally, these attacks against the oil and gas infrastructure gave the terrorist groups political and tactical advantages. First, as Colombia's prime area of growth of foreign direct investment in the last years has been the mineral industries, in order to secure the growth of these activities in the country, the Colombian government had to allocate army forces to guard the oil and gas infrastructure. As of July of 2012, 20,000 military men were deployed for this activity only. Second, the attacks and damage from the terrorist groups to the oil and gas infrastructure create a perception of doubt and insecurity among citizens and foreign investors. Consequently giving the terrorist groups some notoriety nationally and internationally (El Tiempo, 2012; Sierra, 2013)

REGIME STABILITY AND LEGAL SYSTEM STABILITY

Regime stability measures the governmental stability that a country or state has and how it could affect a company's future. The stability or instability will lead to political risk actions that could damage seriously the financial position of a company. Within those the more common actions that the region has suffered in the past and that could occur in the future are: the nationalization and expropriation of oil companies assets, and also repatriation restrictions or currency inconvertibility (Skipper, 432). Legal system stability is basically an indicator of the regime stability, as it is one of the tools that governments use to perform the actions explained before, and also serves as the framework that determines the different type of contracts and laws that companies have to abide by in order to operate in a given country.

From 2005 to 2012, some countries within South America have nationalized to some extent part of their hydrocarbon sector. Pursuing *the ultimate benefit of the people,* heavy-handed expropriation of assets from private companies had occurred. Venezuela has been the biggest nationalizer/expropriator in the region. Under the government of

President Hugo Chavez in 2007 major nationalization and expropriation took place in Venezuela. Energy firms, including ExxonMobil, British Petroleum (BP) and ConocoPhillips lost their assets in the country. Other companies that were present in Venezuela during those years were forced to pay higher royalties in order to continue operating in the country (Brune, 2010).

In similar circumstances, in 2006 President Evo Morales nationalized Bolivia's oil and gas reserves, which by that time were the second largest proven reserves in the region. Additionally, he also took control over the production and commercial operation of private companies present in the country. Likewise, Ecuador President Rafael Correa canceled the contract that Occidental Petroleum –Oxy- had in the country in 2006 and took possession of their production assets. Later, President Correa would change the contract conditions of all the contracts in-place with oil and gas firms and impose a 99% windfall revenue tax on oil. Furthermore, in 2009 President Correa expropriated two blocks that belonged to Perenco, an Anglo-French oil firm (Brune, 2010). Finally, on July 27, 2010 President Correa enacted a bill that give him the power to nationalize foreign companies that refuse to sign the new contractual agreements (MercoPress, 2010). By November 2010, the Ecuador government successfully renegotiated all the contracts with foreign oil companies replacing its production-sharing agreements to new service contracts in which the government owns the oil and natural gas produced. ("Country Analysis Brief Overview: Ecuador", 2012).

Finally, the most recent action of this type and probably the one that is crucial to shale gas development is the expropriation of YPF oil and gas firm that the Argentina government took in late April of 2012. YPF, which was under the control of the Spanish firm Repsol since 1999 was expropriated on the basis that the company was underinvesting in the country ("Country Analysis Brief Overview: Argentina", 2012). As a consequence of this, the Argentina government argued that oil and gas production had declined in the recent years, forcing Argentina import oil and gas from foreign countries. This situation raised concerns about foreign investments in the region and also regarding Argentina's government making additional expropriations of foreign companies in the future (Flintoff, 2012).

Colombia, is seen in South America as one of the best countries to do business within the oil and gas industry with Brazil because of its fiscal regime and political stability (Lafaurie, 2012). However, all the different events discussed previously have stigmatized the region as prone for nationalizations and expropriations and by doing so it has branded Colombia and Brazil as possible cases of these actions in the future. Nevertheless, for the fortune of Colombia, the analysis of the previous events has concluded that nationalizations and expropriations are more likely to occur in socialist governments. These types of governments tend to change the conditions of the contracts they signed with foreign oil companies (e.g. Venezuela, Ecuador, Bolivia), looking to increase the revenues they gain from oil and gas operations within their countries. As shale resources operations are basically a type of oil and gas procedure, the possibility that such acts could happen in the future is high. As soon as major discoveries start to appear and major revenues start to be obtained by the foreign company, the national government will be looking to obtain more economic resources to manage their social policies. This is similar to what has happened in Venezuela and could lead to a country changing the rules of the contracts or going further and making nationalizations or expropriations, seeking to gain ownership of the specialized equipment required to perform these types of operations.

Petroleum Risk Assessment of Colombia

Of all the risk that can be classified within the *petroleum risks* category, probably some of the most important that Colombia is exposed to currently are: the lack of experienced human capital, the time to obtain operation licenses, the lack of critical equipment and required knowledge to use it, and finally its precarious infrastructure. There are many more that could be even more important like: the geologic risk, which creates production-rate risk, commodity-price risk and operating-cost risk (Gustavson, 3). However, as Gustavson explains these type of risks are inherent to all oil and gas production activities, thus anywhere in the world an operator will be exposed to them. Therefore, the analysis, repercussions and possible solutions for Colombia do not differ so much from the ones given by Gustavson in his paper (Gustavson, 3-4).

HUMAN CAPITAL RISK

Deloitte Consulting described precisely the problem of the human capital risk in their report *Drilling for talent in the new millennium* by stating that "the industry is facing ever-increasing pressure to retain an aging workforce -greater than 50% is over 45 years old- and at the same time facing higher costs while employing creative techniques to harness the knowledge they possess. Other challenges regarding this risk include "attracting and deploying the next generation of upstream experts and growing a global resource pool positioned to move swiftly and efficiently" (Deloitte, 2009). This problem, which is global, is suffered also in South America and Colombia.

Related to the development of shale resources in Colombia, this risk is quite high because the techniques used in shale operations while not totally new to the Colombian oil and gas industry (Tovar Aguirre, 2008), have not been performed in the way shale resources require. The use of both techniques as explained in Chapter 1 has been utilized in different periods during the lifetime of the oil fields. Thus, these facts could create a bottle neck on human capital in the country and also it could lead to the increase of the operation costs for the first wells, as employees with the knowledge will ask higher payments in return of their knowledge. Additionally, an ageing workforce that has not been exposed to these techniques and their use in shale formations could be reluctant to learn those techniques, creating a possible scenario of early retirement of this workforce. Consequently, making the problem of finding trained human capital more difficult. Furthermore, if we consider that other shale-rich countries in South America, like Argentina and Brazil and not too far away the U.S., are also looking to hire this type of human capital the risk basically increases (Vaca Coca, 2013;Ernst & Young, 2011). Moreover, the requirement that local governments, unions and also the ANH to some extent, have posed over oil and gas companies operating in Colombia to hire preferably nationals as a way to promote local workers makes the situation more complex and leads to a higher risk *("Minuta Contrato E&P")*. Additionally, there are an insufficient number of specialized courses, which reflects on the poor development of the education system within Colombia and the region related to the oil and gas industry, which finally contributes to a high deficit in qualified personnel ("Ingeniería del petróleo"). Furthermore, the oil and gas industry suffers from a bad brand image, influencing freshmen to choose other lines of studies (Ernst & Young, 2011).

OPERATIONAL LICENSING RISK

An additional *petroleum risk* that has been growing in the recent years in the oil and gas industry is the amount of time that is required to obtain certain oil and gas operating licenses. In Colombia the environmental licenses, which are required by the operator to be able to do any type of operation in their lease land, are the most critical.

According to the Colombian Petroleum Association –Asociación Colombiana de Petroleo in Spanish– (ACP) out of the 22 licenses requested by operators between 2010 and 2011 to the Environmental Licensing Agency –Autoridad Nacional de Licencias Ambientales in Spanish– (ANLA) none were approved by the governmental agency in March of 2012. These licenses could have given Colombia in 2012 an additional production of 120,000 barrels of oil per day. Furthermore, in 2012 some of the laws regarding new licenses were considered for modification. According to the National Business Association of Colombia –Asociación Nacional de Empresarios de Colombia in Spanish– (ANDI) these changes will make the process of obtaining the licenses harder and delay them further, which will create an environment of uncertainty and higher costs for the industry (Portafolio, 2012).

Considering that this situation of long delays on issuing the licenses is happening where the industry techniques and practices are quite common to the industry and the Colombian environmental licensing agency; the possibility that environmental licenses for hydraulic fracturing operations be given in a timely manner is minimal. Not only the environmental agency faces many uncertainties regarding the process, but also its judgment about the operations could be distorted if we consider the scattered information that can be found regarding them nowadays. Stories related to bad casing jobs, gas flaring, natural gas flowing out of faucets and so on is continuously in the news, thus making the public not only more aware but reluctant to have this operations near them, which has created a Not In My Back Yard (NIMBY) phenomenon (Seelye, 2011; Bateman, 2010). The phenomenon has escalated so much that states and countries that have the resources in place have banned their development, like France did in 2011 (Jolly, 2013). The possibility of banning hydraulic fracturing operations in Colombia is almost null, if we consider all the efforts that both the Colombian government and operators have shown towards proving their interest and support for the exploration and production of the Colombian unconventional resources. However, an ever more scrutinized review of the operational environmental licenses is likely to occur. Thus, leading to the delay of operations and to some extent the discouragement of possible new operators.

Furthermore, an additional risk that derives from the delay of issuing the licenses is the financial risk associated with the delay. If those licenses take more time than they should, the operator according to the fiscal regime of Colombia, explained before, will incur additional payments for the use of the subsoil and also could face the payment of additional costs to maintain their leases. Additionally, considering that the ANH requires that the operator perform a *minimum exploration program* within a specific amount of time, if the proper licenses to perform those jobs have not being issued, the operator will incur in cost overruns or even losing the leases, since not performing the *minimum exploration program* is an early termination clause of the contract ("*Minuta Contrato E&P*").

CRITICAL EQUIPMENT

Considering the criticality of the equipment required for hydraulic fracturing operations (Chapter One), the risks that they create in the operations are high. An example of this is the case of the Frac Blender. As Paul Bommer explains, the Frac Blender is one of the most important and critical equipment not only because of its unique capabilities of mixing the fluids, chemicals and proppants required to perform the *frac job*, but because of the fact that it is scarce equipment, thus if a fracturing crew looses one while performing the job, the options of getting a new one are little or will demand a lot of money (Bommer, 2012). Additionally to its scarceness, the risks that the blender creates increase considering that it is one of the most expensive equipment used in the frac job. As Daniel presents on its report of the Perspectives on the National Association of Manufacturers (NAM) Pressure Pumping Market, a blender in 2010 could cost around $1 MM dollars and its useful life with the demand that this type of equipment has does not surpass three years (Daniel, 2010). Furthermore, as more shale plays are discovered in the U.S. and in countries around South America, this equipment will become scarcer, thus creating a bottleneck for the industry in Colombia. Which will determine that the rates for contracting the services of fracturing crews could rise.

The case for the blender is not the most extreme one could imagine, and unfortunately replicates to all the other critical equipment. As Güimar Vaca Coca presented, Argentina, which is one of the richer shale-countries in the world and one that has worked constantly to produce its resources, has already experienced scarceness of hydraulic fracturing equipment. He explained that as of February 2013, Argentina only had 7 complete frac-crews and only 5 coiled tubing units that could perform completely hydraulic fracturing operations (Vaca Coca, 2013). Additionally, if we considered that by 2008 Argentina was performing from 4,000 to 6,000 fracturing jobs per year, meanwhile in Colombia the industry was performing less than 1,000 jobs (Tovar Aguirre, 2008), the risk of not having the required equipment to perform the jobs is high.

CHAPTER 5. FINANCIAL ANALYSIS

Background and Assumptions

Following will be explained a financial analysis model made for a shale project in Colombia. The model is based primarily on some of the information presented on the previous chapters of this thesis, coupled with additional information needed specifically for the creation of the model. The interest on creating this model was to review the viability of a project of these characteristics in Colombia. Additionally, to review the impact of some of the findings made from the research for this thesis like: the change made by the Colombian government on their fiscal regime for shale projects, the risks (geological and political) that Colombia presents on such project. But, before explaining the findings of the model, it is important to explain some of the assumptions defined for the model.

1. The model is basically a Discount Free Cash Flow analysis of a shale project in Colombia. This type of analysis is widely used in the oil and gas industry, as confirmed by the findings of the survey made by the Society of Petroleum Evaluator Engineers in 2011 (figure 20) (Kasriel and Wood, 12).

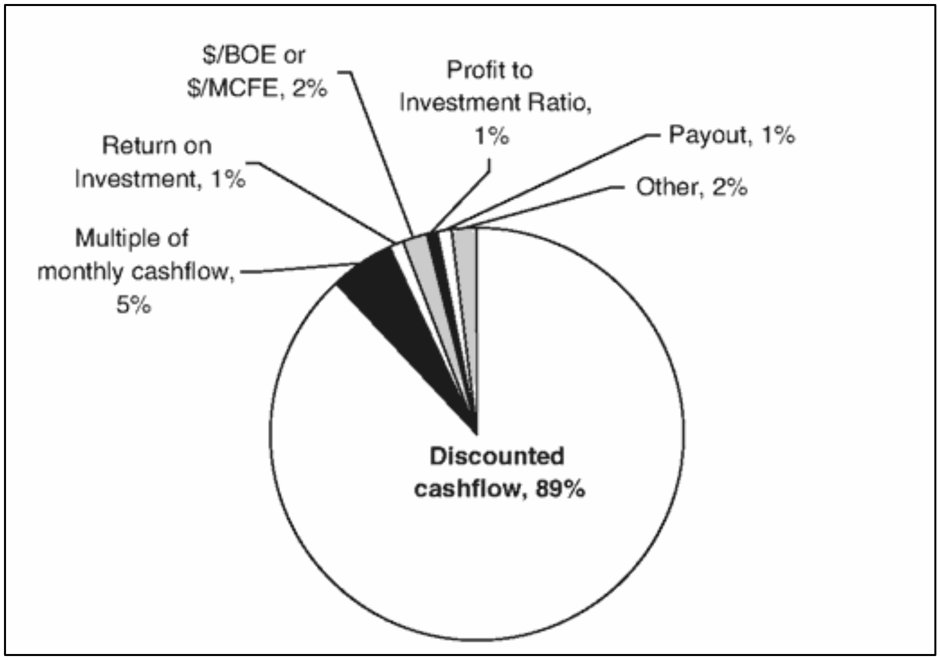

Figure 20. SPEE 2011 Survey, "Most Commonly Used Method for determining Value of Oil and Gas Properties" Souce: Kasriel and Wood, 12.

2. The model includes all the determinants of government take of the fiscal regime of Colombia, explained in Chapter 3 of this Thesis.
3. The production profile was created based on the findings from Fan Li et al., described on the SPE paper 148751 "An Integrated Approach for Understanding Oil and Gas Reserves Potential in Eagle Ford Shale Formation", presented at the Canadian Unconventional Resources Conference (Fan Li, et al., 2011). Based on their research a well in the Eagle Ford Shale Formation can produce during a 30-year period up to 620,000 barrels of oil and up to 480,000 MScf (figure 21). Oil production peaks at 220,000 bbls and gas production peaks at 70,000 MScf, both at year 1 (figure 21). From that year, the production declines following the patterns of an exponential decline curve. The use of this production curve

for the model relates to the fact that, as presented on Chapter 1, La Luna Formation in Colombia relates closely to the Eagle Ford Shale Formation in the United States.

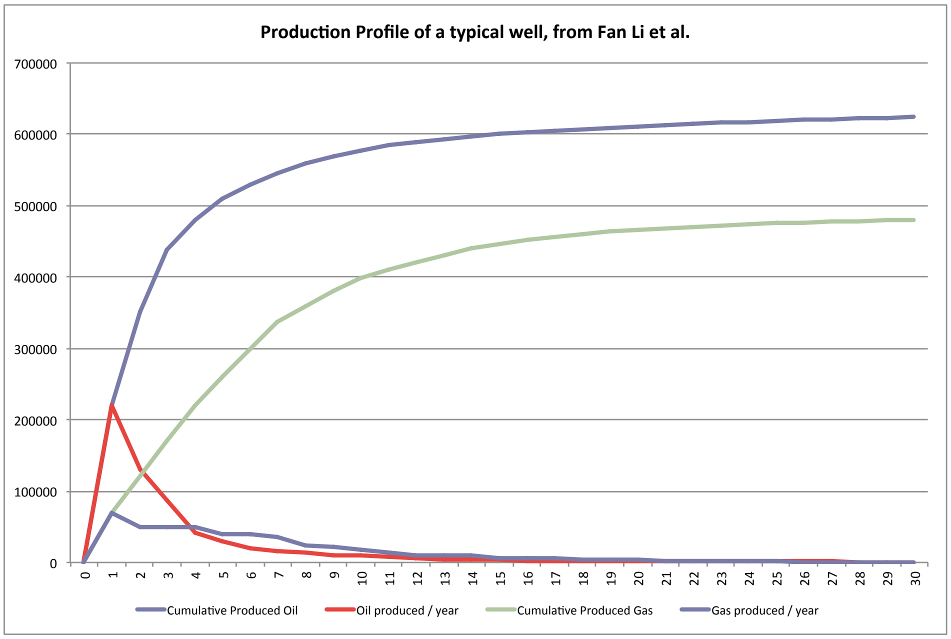

Figure 21. Production profile of a typical well in the Eagle Ford shale reservoir. Source: Modified from Fan Li, et al., 2011.

4. The geology information used in the model is based on the information presented by Sintana Energy for their block VVM 37 in Colombia (Sintana Energy, 2012). Out of this information I obtained the figures for P10, P50 and P90 of the unrisked resources in place within the block (table 7). These three values were used to establish the low, best and high scenarios. The number after P represents probability that the resources determined will be obtained. Thus P90 is the lowest scenario as the assumption is that those resources have a 90% probability to be

discovered, likewise P50 is the best scenario as there is a 50% probability to recover those resources. Finally P10 is the high scenario as the probability to obtained the resources determined is only of 10%. The information extracted for P10, P50 and P90, was used in the model not as resources but as reserves. This is a major assumption and a necessary one, in order to be consistent in the determination of the different government takes. To risk the resource estimation for each scenario a 10% was applied to each unrisked scenario value (table 7). Finally, the figures of Sintana Energy projected NPVs before taxes were used to review the accuracy of the proposed DCF model.

Table 7. Resource Estimation for the Colombian Shale Project

Resources Estimation			
Type of Resources	Low Estimate P90	Best Estimate P50	High Estimate P10
Risked	16.8	70.0	175.0
UnRisked	168.0	700.0	1750.0

Source: Modified from Sintana Energy, 2012.

5. The model runs on the assumption that there is no limit on the number of wells that the operator can drill within a year. Thus the model is run to maximize the number of wells, which will produce accordingly to the declined curved described in No. 3. Consequently the operator will be able to extract close to the 100% of the total reserves within the period lenght of the contract with the ANH.
6. Related to the previous assumption, the model assumes that the operator in order to produce the total reserves of the field will drill the same number of wells per year during the total length of the contract.

7. The price of the hydrocarbons produced is constant for the duration of the contract. The price for oil was set at $95 dollars per barrel and for gas it was determined at $5 per MScf.
8. It was assumed a 25% Tax Rate for all the scenarios of the model, considering that this is the rate for a company that establishes a branch in Colombia. Not establishing one will impose a tax rate of 33%. Review of the different companies already in the country show that is the common practice, and also from a financial and accounting point of view that will be for the best interest for a company given the 8% that the company will save by establishing one.
9. The acreage of the block used for the model (43,160 acres) is the same one as the VVM 37 block of Sintana Energy in the Middle Magdalena Valley Basin of Colombia. This value was maintained constant for the calculation of the fees for the use of the subsoil.
10. The expenses for the exploration phase where maintained constant in the model. The expenses follow the guidelines of the ANH for the minimum exploration program for a block assigned throw a bidding process with the Colombian agency. The values are presented on Table 8.

Table 8. Minimum Exploration Program for the Colombian Shale Project

Minimum Exploration Program	Value US$		Units	Quantity	Total	
Aero-geophysics	$	185	US$/km	0.5	$	32,313
Exploratory Well	$	16,000,000	MMUS$	2	$	32,000,000
Stratigraphic Well	$	14,000,000	MMUS$	2	$	28,000,000
Seísmic Reproc & Interp	$	109	US$/km	52.40	$	5,711.46
2D Seísmic	$	43,456	US$/km	34.93	$	1,518,025
3D Seísmic	$	69,529	US$/km2	17.47	$	1,214,410
Grand Total					**$**	**62,770,459**

Source: Author creation based on the guidelines of the ANH Contract.

Findings

In the following pages is presented the sensitivity analysis of the model created for the financial analysis of a project of shale resources in the Middle Magdalena Valley Basin of Colombia. The findings were the following.

1. For the first analysis were used the following additional assumptions: There was not change on the max production of a well. And the reservoir produces a 100% of the oil and gas present on it. Using the Best, Low and High scenarios we were able to identify that all projects show positive NPVs (Table 9). This reflects the high production of oil and the price of it.

Table 9. Minimum Exploration Program for the Colombian Shale Project

NPV & IRR of Low, Best & High Scenarios, by maximizing # wells to produce as much of total reserves						
NPV	IRR	Total Reserves	Total Prod	Risked (10%)	Scenario	Max Wells
$ 7,156,943,385	65.8%	700.0	698,867,360	No	Best	1235
$ 699,382,925	45.5%	70.0	67,851,200	Yes	Best	120
$ 1,710,795,395	56.7%	168.0	166,235,440	No	Low	295
$ 111,902,809	21.6%	16.8	15,266,520	Yes	Low	28
$ 17,433,808,701	67.3%	1750.0	1,747,168,400	No	High	3091
$ 1,780,195,409	57.1%	175.0	173,020,560	Yes	High	305

Source: Authors creation

2. The Tornado Diagram sensitivity analysis of the best scenario without risking the reserves presents that the most important variables that have the highest impact on the NPV for this scenario are the percentage change of the maximum production of a well, the discount rate and the price of oil (figure 22). On the contrary, the variables that have less impact on the NPV of this scenario are the variance of the inflation rate and the variance of the length of the exploration phase (figure 22). Tornado sensitivity analysis “measures the input of each variable one at a time, independently, on the target forecast” (Titman and Martin, 72); in this case the NPV.

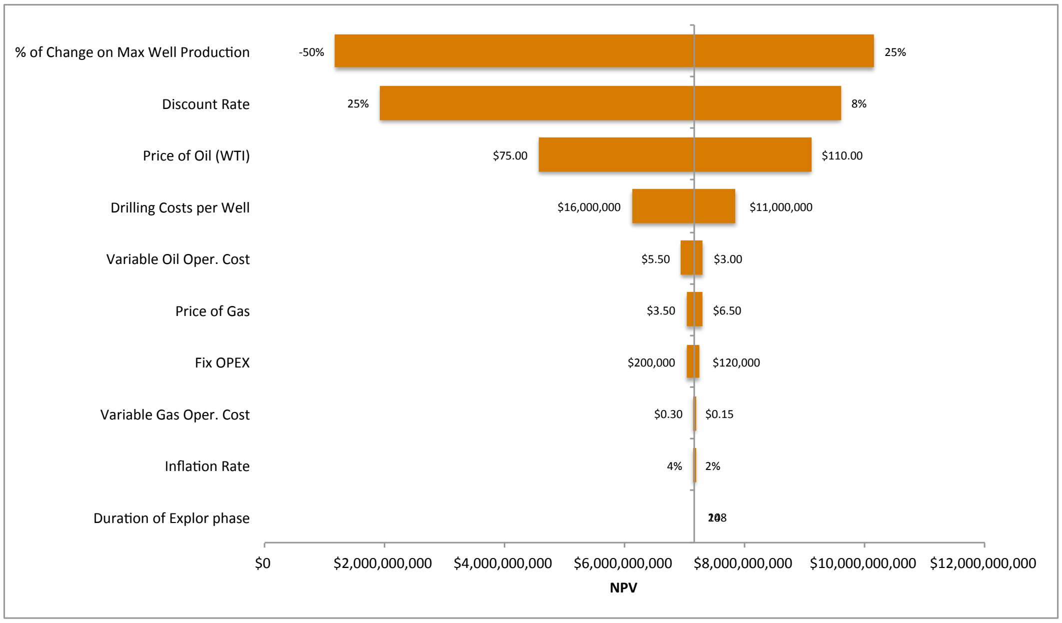

Figure 22. Tornado diagram for the valuation model of the best scenario with unrisked reserves. Source: Authors creation.

The Tornado Diagram sensitivity analysis of the best scenario risking the reserves (figure 23) presents almost the same results as the one for unrisked reserves (figure 22). At a first sight the difference is only the quantity of the values, which is consistent given the reduction made on the quantity of reserves. However, analyzing the resulting values for both tornado diagram sensitivity analysis, the biggest difference between them is in the discount rate that would make the NPV to be cero (table 10).

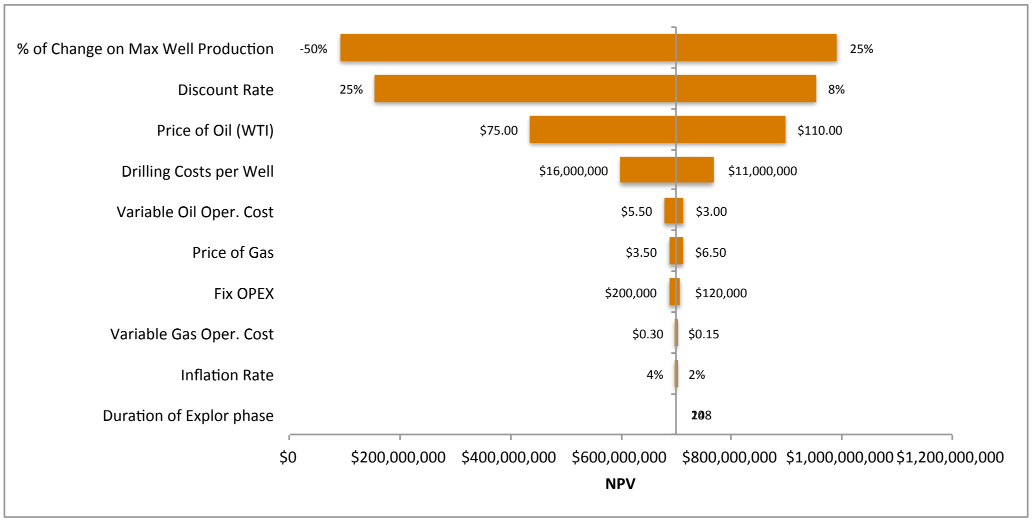

Figure 22. Tornado diagram for the valuation model of the best scenario with risked reserves. Source: Authors creation.

Table 10. Analysis of the differences between the Tornado diagram sensibility analysis of the risked and unrisked best scenario.

Inputs	UnRisked Reserves	Risked Reserves	Difference
% of Change on Max Well Production	-59.8%	-57.4%	-2.5%
Discount Rate	**65.8%**	**45.5%**	**20.4%**
Price of Oil (WTI)	$ 39.87	$ 42.21	$ (2.34)
Drilling Costs per Well	$ 33,611,457.11	$ 33,745,951.72	$ (134,494.61)
Variable Oil Operation Costs	$ 52.81	$ 53.13	$ (0.32)
Price of Gas	$ (76.65)	$ (76.91)	$ 0.26
Fix OPEX	$ 2,827,536.85	$ 2,845,008.41	$ (17,471.56)
Variable Gas Operation Costs	$ 80.07	$ 80.59	$ (0.52)
Inflation Rate	N/A	N/A	N/A
Duration of Exploration phase	N/A	N/A	N/A

Source: Authors creation.

3. The next sensitivity analysis done was determining the different NPVs and IRRs of the best scenario, with risked and unrisked reserves, when changing the amount of oil and gas found and produced from the field. The different scenarios modeled and analyzed were the following: finding gas only, then finding only oil, and finally a mix of finding gas and oil in

different proportions, always adding up to one (25% gas, 75% oil; 50% gas and 50% oil; and, 75% gas, 25% oil). All the results are summarized in table 11. As in the tornado diagram analysis, we can see that the change in the percentage of oil or gas in the reservoir is the most important driver for the NPV of the project. When the oil produced from the field is less than 43% the NPV of the project will always be negative. This is an important find as it determines that a project where the reservoir only produces gas will not be economically, given the actual circumstances of price and amount of the reserves find on it.

Table 11. NPV & IRR analysis for risked and unrisked reserves in the best scenario, changing the percentage of oil and gas produced from the field.

NPV & IRR of Best Scenario, for risked and unrisked reserves changing the % of oil and gas produced from the field				
NPV	IRR	Oil %	Gas %	Risked (10%)
$ 7,156,943,385	65.8%	100%	100%	No
$ 699,382,925	45.5%	100%	100%	Yes
$ 1,176,987,330	19.6%	50%	50%	No
$ 91,591,825	15.2%	50%	50%	Yes
$ (1,660,621,938)	N/A	25%	75%	No
$ (204,358,329)	-9.8%	25%	75%	Yes
$ 4,014,198,503	41.6%	75%	25%	No
$ 387,264,616	30.2%	75%	25%	Yes
$ 6,851,489,005	63.7%	100%	0%	No
$ 669,606,158	44.2%	100%	0%	Yes
$ (4,571,781,685)	N/A	0%	100%	No
$ (500,394,860)	N/A	0%	100%	Yes

Source: Authors creation.

CHAPTER 6. CHALLENGES AND OPPORTUNITIES

Winston Churchill said once “A pessimist sees the difficulty in every opportunity; an optimist sees the opportunity in every difficulty.” (Langworth, 578). Such words will describe essentially the environment that Colombian shale resources are currently facing. These resources bring to the Colombian oil and gas industry a new scenario, where many challenges and opportunities arise to the companies that are willing to work on it. Those challenges and opportunities are created from many sources, must of which were described and analyzed in the previous chapters. Thus, as a SWOT analysis is one of the main summary points of a market analysis (Hasler, 2013), for this Thesis the summary point or conclusions of the different analysis done previously will be the determination of the challenges and opportunities which will be present below.

Challenges

The main challenges identified from the analysis of the previous chapters are:

1. Most of the risks described in detail in Chapter 5 represent a challenge for Colombia’s shale resources from a standpoint of an interested operator. Of those, the most important are the ones explained in the *petroleum risks category*, as they relate to the operation itself, and will require a lot of analysis and mitigation from the operator.
2. The Colombian government needs to work extensively on their environmental and operational licensing processes. Shale oil and gas projects require unlike conventional ones a lot of drilling and completion activities, almost in a fifteen-times ratio -for each well drilled in a conventional oilfield, an unconventional field will require almost 15 wells

to produce almost the same amount of production- thus the number of licenses for performing the different activities related to it will be huge. Therefore this is an area that could become a big challenge for an operator willing to produce the shale resources found in a lease assigned by the ANH.

3. The knowledge of the geology of the Colombian shale basins is still premature. While some work has been done in the past to come up with the values presented in Chapter 2, the information is still not solid enough. Thus, creating an uncertain environment regarding the resources and reserves of the country.
4. Pipeline availability capacity is a major challenge that an operator would have to overcome for either oil or gas. While there are many projects that have been undertaken to increase the capacity of the pipelines of Colombia, almost all this new capacity is already accounted for by the large amount of oil that is moved by trucks. Thus, a new operator in the country will have to either move their oil by truck or engage in different agreements to acquire some of the capacity available in the existing pipelines.
5. Finally, a minor challenge for operators and the government is how to control and manage hybrid production (production from an oil field that produces from conventional and unconventional reservoirs) given that the fiscal regime establishes completely different government intakes.

Opportunities

The main opportunities identified from the analysis of the previous chapters are:

1. The shale geology present in Colombia is a really good one considering that most of its plays and basins are oil prone. Oil has always been more expensive than gas, and with the price of oil in the $90 dollar range per barrel, makes almost every project considered profitable, if the reserves present are large.
2. The petroleum fiscal regime of Colombia, not only for shale but also for conventional reservoirs since 2004 has been considered as one of the best in the world. The further modifications that the ANH made to it for unconventional reservoirs, makes it even more appealing to operators, because by escalating the royalties based on the production, even a small project can be profitable as shown in the financial analysis.
3. Shale gas resources and other unconventional resources (CBM) will provide major gas capacity that can be exploited to the benefit of the different players of the gas market. Additionally, coupled with the strategic geographical position of Colombia, having access to both oceans increases the possibilities for exporting gas. LNG and pipeline export projects to provide gas to the Caribbean and Centro America, can allow shale projects that produce more gas than oil to become also economically viable.
4. Colombia's hydraulic surface resources can provide sufficiently the water required by shale gas operations without creating the dilemmas of water usage that have been reported in other countries like the U.S. in the Eagle

Ford shale play. Additionally, considering that the most important basin (Middle Magdalena Valley Basin) is closed to the Rio Magdalena, there is an opportunity that given the pipeline constraints, oil produced from shale fields in this basin could be move by barge up to the export ports in the Atlantic.

Outlook and further research

The outlook of the shale resources in Colombia is promising, as the Colombian government has created a positive environment for it by developing some mechanism (lowering royalty scheme, and so on) to incentivize it. Additionally, Colombia's security and political situation has being improving so much in the last two decades that it is right now considered one of the best countries to conduct business in the oil and gas industry in Latin America. Just this, plus the good geology that the country has, makes it look like the future for it is really good. Further research in this topic should revolve around three main areas: First, use a Real-Options approach for the financial analysis; second, analyze and/or forecast the implications of shale gas resources in the gas market (national and international) where some research done during this thesis shows will be were major impacts could be faced in the future; and finally, further geological research to develop better geology information to asses the different basins and their resources in Colombia. If the La Luna Formation is as important as the research in Chapter 2 suggests, there is much work that could be done. More explanation of these three topics follows.

Considering that the petroleum fiscal regime of Colombia, and more specifically the contract in place for the E&P projects develops in phases a better approach to evaluate financially shale gas projects in Colombia should be using Real-Options

Analysis. By using this type of analysis a company can actually evaluate the options (decision opportunities) that will face during each of the three determined phases of the contract. By doing so, the company can take advantage of the options that the Colombian government gave in the contract, like walking away of the project or simply taking more time to define their strategy, which could be either produce the field or sell the block to another company in a farm-in/farm-out transaction.

The gas market in Colombia has many more constraints and variables than the oil market. Essentially the oil market in Colombia is comprised of internal consumption, which is the oil refined at the 4 refineries of Colombia; and the exports made by the different companies operating on it, which represent the larger volume of it. In contrast, the gas market has many players. In the demand side, there are the end consumers, industry, transportation, LNG export projects, exports to nearby countries and the government. Their interaction can create many different forecasts. Likewise, on the supply side, there are conventional gas fields, future shale gas fields, Coal Bed Methane production that the government is trying to incentivize too, and also LNG import facilities. All of them create a more complex scenario, if considered all together. Thus understanding and modeling their interactions could determine the real impact of shale gas resources in the Colombian and Latin America gas market.

Finally, La Luna Formation has being described as one of the most important shale plays in the world by different entities. Some of which were included in Chapter 2. Thus, the more geological analysis that could be done about it will derived in larger and more accurate information that will help on the efforts to award the blocks in future bidding rounds the ANH perform for shale resources in the country.

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