QUANTIFICATION OF THE UNCERTAINTIES IN SHALE GAS RESERVOIRS, A CASE STUDY FOR DADAS SHALE FORMATION

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ABSTRACT

QUANTIFICATION OF THE UNCERTAINTIES IN SHALE GAS RESERVOIRS,
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In the world of a decreasing conventional oil and gas resources and high energy prices, the unconventional gas resources has become a new focus of interest of the oil and gas industry. Especially, after the American shale gas revolution, both the industry and the economies are trying to explore and exploit their potential resources. Also, Turkey is one of the lucky countries that are known to have important shale gas resources at subsurface. Up to date, Dadas shale formation in the Southeastern Anatolian basin is regarded as the most promising one among the country. Although, the exact amount and reservoir charactersictics are not determined due to the lack of sufficient engineering and reservoir data, the exploration activities are continuing to get tangible information. While the first wells are being drilled in the field within the scope of the development plan, this study sets out to estimate the gas reserves in the Dadas shale formation by quantification of the uncertainties by using some probabilistic approaches and discuss the economic viability of the field. The estimation of Original Gas İn Place (OGIP) as 88,6 Tcf, Recovery Factor (RF) as 15%, Technically Recoverable Resources (TRR) as 13,3 Tcf, the optimum well number of 5189 wells and the well spacing of 233 acres/wells are illustrated. The Net Present Value (NPV) and the Internal Rate of Return of two different field development plans are projected and compared. The first one has a drilling program in the first 10 years of the project with a 25 years' life cycle and the other one has a drilling program in the first 25 years of the project with a 40 years' life cycle.

Keywords: Shale gas, Dadas, Turkey, uncertainty, economic viability.

ÖZ

ŞEYL GAZI REZERVUARLARINDA BELİRSİZLİKLERİN GİDERİLMESİ,
DADAŞ ŞEYL FORMASYONU İÇİN BİR DURUM ÇALIŞMASI

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Konvansiyonel petrol ve gaz kaynaklarının giderek azaldığı ve enerji fiyatlarının da artış eğiliminde olduğu bir dünyada, konvansiyonal olmayan gaz kaynakları, petrol ve doğal gaz endüstrisinin yeni ilgi odağı olma yolundadır. Özellikle, Amerikan şeyl gazı devrimi sonrasında, gerek petrol endüstrisi gerekse de dünya ekonomileri, sahip oldukları potansiyel şeyl gazı kaynaklarını arama ve yeryüzüne çıkarma çabasındalardır. Türkiye de, toprakları altında önemli şeyl gazı kaynakları olduğu varsayılan ülkeler arasında yer almaktadır. Güneydoğu Anadolu baseninde yer alan Dadaş formasyonu, mevcutlar içinde en umut verici olan ana kaya olarak nitelendirilmektedir. Ne yazık ki, yeterli miktarda teknik veri olmadığı için rezerv miktarı ve rezervuar özellikleri tam olarak bilinmese de, bu konudaki arama faaliyetleri devam etmektedir. Söz konusu saha geliştirme planı kapsamında ilk kuyular kazılırken, bu çalışmada, rezervuar hakkındaki bazı belirsizlikleri gidermek için olasılıkçı yaklaşımlardan yararlanarak rezerv miktarı belirlenmeye ve sahanın geliştirilip üretime geçilmesi için gerekli ekonomik yatırımın yaklaşık miktarının tespit edilmesine çalışılmıştır. Bu doğrultuda, Dadas formasyonunu içerdiği 88,6 Tcf' lik yerinde gaz miktarı, %15' lik kurtarma oranı ve 13,3 Tcf' lik üretilebilir kaynak miktarı hesaplanacak, ardından sahada açılması gereken optimum kuyu sayısı 5189 olarak belirlenecek ve ilk 10 yılında gerekli sondajların tamamlanmasını öngören 25 yıllık saha geliştirme ve üretim planı ile ilk 25 yılında gerekli sondajların tamamlanmasını öngören 40 yıllık saha geliştirme ve üretim planları kapsamında projenin Net Bugünki Değeri ile İç Karlılık Oranı hesaplanacak ve gerekli karşılaştırma yapılacaktır.

Anahtar kelimeler: Şeyl gazı, Dadaş, Türkiye, belirsizlik, ekonomik analiz.

To me,

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TABLE OF CONTENTS

LIST OF TABLES

TABLES

LIST OF FIGURES

LIST OF SYMBOLS

Symbols	Definition
A	Area (Acres)
ARI	Advanced Resources International
BCF	Billion cubic feet
BCM	Billion cubic meter
B_{gi}	Initial Gas Volume Factor
C	Present Value of Capital Investment per Well
CAPEX	Capital Expenditures
D	Darcy
DOE	U.S. Department of Energy
E&P	Exploraiton and Production
EIA	Energy Information Administration
EUR	Estimated Ultimated Recovery
F&DC	Finding and Development Costs
H	Net Pay (Ft)
I	Interest or Discount Rate, Fraction per Annum
IEA	International Energy Agency
IRR	Internal Rate of Return
M^3	Cubic meter
MIT	Massachutsetts Institute of Technology
MMSCF	Million Standard Cubic Feet
Np	Cumulative Producible Gas
NPV	Net Present Value
OGIP	Original Gas In Place

OPEX	Operational Expenditures
Q	Initial Gas Production Rate per Well
Q_n	Flow Rate in year n,
RF	Recovery Factor
SCF	Standard Cubic Feet
Sg	Gas Saturation (Fraction)
Sw	Water Saturation (Fraction)
TCF	Trillion cubic feet
TCM	Trillion cubic meter
TOC	Total Organic Content
TPAO	Turkish Petroleum Corporation
TRR	Technically Recoverable Resources
V	Gas Price Netted Back to the Well
W_o	Optimum Number of Wells
α	Annual Decline Rate
Φ	Porosity (Fraction)

CHAPTER 1

INTRODUCTION

The greatest energy innovation of the decade, according to Daniel Yergin, is unconventional natural gas (Yergin and Ineson, 2009). Unconventional gas resources stand for an inevitable alternative in the period of a diminishing conventional gas production and increasing demand. Also, among these resources, shale gas has become a phenomenon in exploration and production for the last decade. Unconventional gas has thus become a topic that is increasingly being debated.

Shale gas, an “unconventional” bonanza has rapidly transformed America’s energy agenda. The success of United States in unconventional gas, especially shale gas production in giant shale plays like Marcellus in Pennsylvania, Barnett in Texas, Haynesville in Louisiana, Fayetteville in Arkansas and Oklahoma, etc. has made it a phenomenon. A country that dependenct on Middle Eastern fossil fuels is now on the verge of self-sufficiency, with the future plan of becoming an exporter in natural gas. Today, the share of the unconventional gas is over the half of the total gas production of the United States of America.

The American revolution affected the international gas markets, even the renewables about the investment decisions. If the current shale boom appears to be deceptive, the World may be confronted with serious problems about the supply security. But, if it enlarges to a global scale, a cheaper gas market would be inevitable. This expectation has awaked engineers, economists and policymakers in many regions of the world to ask if there exist any new reserves of this valuable under their soils.

Shale gas, regarded as a *game changer*, has became a point of interest all over the world with tangible effects on the energy markets fundamentals after the production boom in the USA. Although Europe is in its infancy of shale gas business due to the legal restricts, economical issues, lack of geological information and industrial infrastructure, there are some substantial activites and future production plans in some countries like France, Poland, Norway, Poland, Ukraine, Sweden and Turkey. Also, it is known that there are significant amount of recoverable shale gas resources in Asia – Pacific region like China, Australia, India and some Latin America countries like Argentina, Brazil and Chile. Even if any production has not started in these countries, it can be said that there are remarkable E&P activities and more important future development plans.

As it is known, Turkey is one of the few countries standing out with its fast and sustainable, at least up to date, economic development even during and after the global financial crisis. In parallel with this development, its requirement for energy is increasing year by year and has become a major natural gas consumer in Europe. Based on the reality that the country is almost completely import dependent on oil and gas, reaching new resources can be regarded as crucial. Under these circumstances, the potential shale gas resources would come to the rescue to increase domestic natural gas production and scale down the import dependency.

This study will focus on estimating the economic viability of the Turkish shale gas plays. The selected resources to be used in the case study are the Dadas shale in the Southeastern Anatolian basin. In addition to the highly uncertain and risky characteristics of the shale gas reservoirs, the lack of adequate geologic and engineering data in the Dadas shale due to the insufficient exploration activity increases the uncertainty level of the reservoir. So the main objective of the study is to quantify these uncertainties by some probabilistic approaches and etimate the shale gas reserves in the formation and evaluate the monetary value of the project if these reserves are to be exploited.

In the first chapter of the study, the unconventional gas resources and the types of them are explained. Then, the question of what the shale gas is and the reasons why it became so attractive by the industry are discussed with its technical background. Also the global shale gas resources and exploration and production activities are given region by region.

In the second part, the main Turkish shale plays, their resource potential, reservoir characteristics and exploration activities in Turkey are discussed in detail. In the third chapter, the problem and scope of the study are stated before some examples from the literature review is given in the fourth chapter.

In the last and fifth chapter of the study, the resource estimation of the selected Dadas shale is done with quantifying uncertainties by some probabilistic approaches. After that, economic viability of this shale play and its monetary value is estimated.

CHAPTER 2

ALL ASPECTS OF SHALE GAS RESOURCES

2.1. Unconventional Gas Resources

As a term, unconventional gas reservoirs are mainly dry natural gas producing reservoirs that having a low - even ultra-low - permeabilities (Holditch, 2007). Infact, it can be said that there is no “typical” unconventional gas. The more easily accessible reservoirs have been generally defined as “conventional” . Reservoirs can vary according to some characteristics like depth, pressure, temperature, fragment design, etc. The important issue is setting free of the gas in these reservoirs that have low, even ultra-low permeabilities and what labeling this process as unconventional gas production is the stimulation to direct the gas from the formation to the wellbore (Kuhn, et al., 2011).

Unconventional gas is usually methane, i.e it has the same chemical composition as “conventional” natural gas. However, reservoir characteristics are unusual and more complex to understand for gas producers and service companies with the current technological masterpiece of the industry (Geny, 2010). The main types of unconventional gas are tight gas, which is found in low permeability rock formations that needs stimulation for gas production, coalbed methane, the natural gas in coal beds and gas hydrates, which is stuck in the icy structures and the frozen ground of the ocean floors which is considered to be the biggest unconventional gas resource, but most such gas is not commercially producible with today’s technologies (Stevens, 2010) and shale gas, natural gas trapped in shales which are also the source rock of the gas (IEA , 2012).

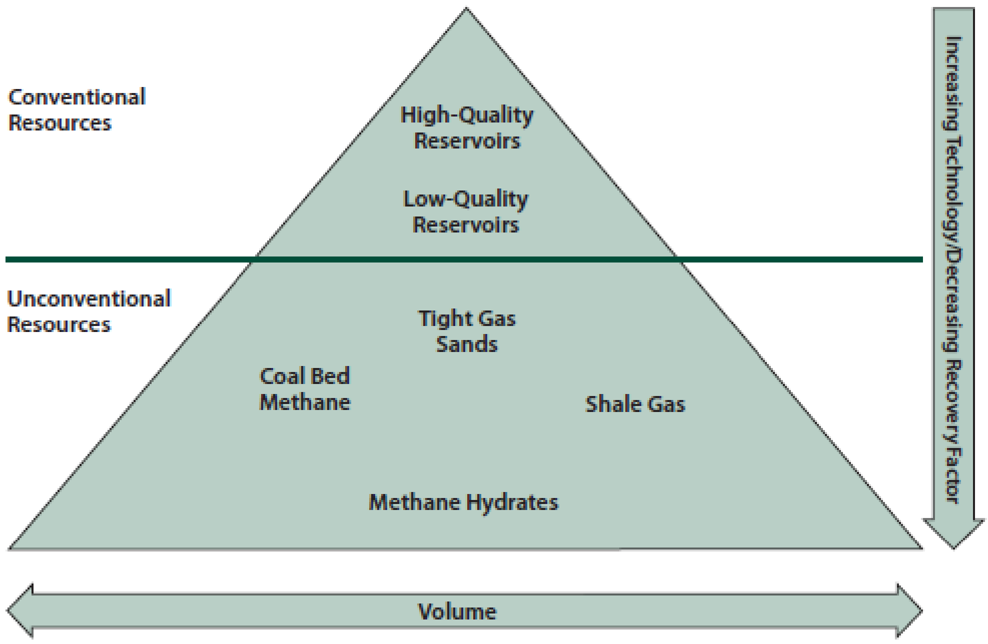

Figure 1: The resource triangle of gas reservoirs. (MIT, 2010)

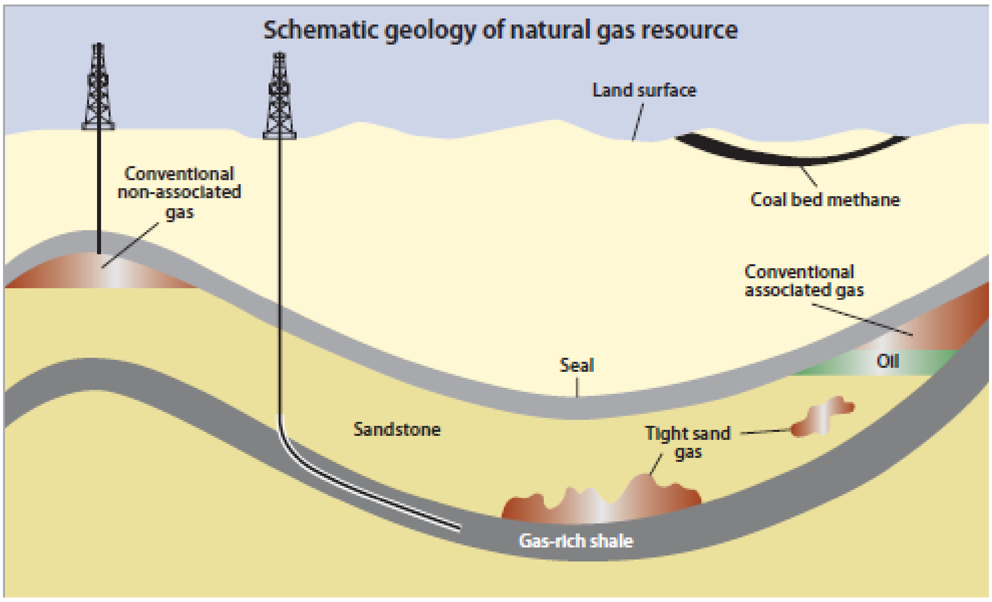

Figure 2: Unconventional gas resources (MIT, 2010).

2.1.1. Methane Hydrates

Methane hydrates are icy forms of methane and water, mainly found in the shallow parts of permafrost areas and continental margins. In a global scale, the methane in the hydrate form is estimated to be above 100,000 Tcf, of which ~99% occurs in ocean sediments. A 10% of these huge resources may be technically recoverable from high-saturation gas hydrate deposits (Boswell, et.al., 2006).

Production of methane from hydrate deposits in sandstone or sandy reservoirs can be treated similarly. As pressure in the well bore is reduced, free water in the formation moves toward the well, causing a region of reduced pressure to spread through the formation. Reduced pressure causes the hydrate to dissociate and release methane (National Energy Techonology Laboratory, 2011).

Methane hydrate may stand for a vast potential resource of far future. Recent researchs are to provide better information about overall resource potential, but many issues remain to be uncertain. While there have been practised limited production tests, the longterm producibility of methane hydrates remains unproven, and broader research is required (MIT, 2010)..

2.1.2. Coal Bed Methane

Coalbed methane (CBM or Coal Bed Methane), coalbed gas, or coal mine methane (CMM) is a form of natural gas extracted from coal beds. In the United States, Canada, and. Australia, it has appeared as an important gas resource. These countries have rich deposits where it can also be known as coal seam gas (Wikipedia, 2013). In Australia, CBM also makes important contributions to the LNG export capacity..

Considerable progress has been made over the last 25 years in developing some techniques to produce coalbed methane feasibly, leading up a significant scale of production, firstly in North America and, since the mid-1990s, in Australia. Coalbed methane can be produced by both vertical or horizontal wells (IEA, 2012). Almost every country all over the world have big or small sizes of coal reserves. Many of them can be mined and have potential CBM recovery. (Holditch, 2007).

2.1.3. Tight Gas

Tight gas is the gas reserves stuck in highly tight underground formations. It is trapped in almost impermeable and hard rocks, or in a sandstone or limestone formation that is extraordinarily impermeable and non-porous.

Typical conventional natural gas deposits have a permeability level of 0.01 to 0.5 darcy. But, the formations trapping tight gas reserves have permeability levels measuring in the millidarcy or microdarcy range. In order to overwhelm the difficulties that the tight formation brings, there are some alternative procedures that can be applied to produce tight gas. Direcitonal drilling practices and detailed seismic data can be useful in exploiting tight gas, as well as artificial stimulation tecniques, such as fracturing and acidizing (Rigzone, 2013).

Within a global scope, there are vast tight gas resources, higher than 32,000 Tcf. The most important reserves are in North America, Latin America, Former Soviet Union and MENA countries. Some systematic evaluation should be carried out on global emerging resources since they are yet to be understood (Holditch, 2007).

Shale and tight gas are currently generating the most media interest. Such deposits have characteristics that are important for their profitability and future prospects.Also, tight gas and shale gas have some common characteristics. For example, compared with conventional gas reserves, shale and tight gas are spread over much wider areas. Also, just like shale gas, tight gas reservoirs needs hydraulic fracturing to be extracted (Stevens, 2010).

2.1.4. Shale Gas

Shale gas is natural gas trapped in shales which are also the source rock of the gas. Shale formations are characterised by low permeability with limited ability of gas to flow through the rock. These formations are often rich in organic matter and are typically the original source of the gas. Shale gas is remained trapped in, or close to, its source rock (IEA, 2012).

The origin of shale gas is the same as that of all hydrocarbons - coal, gas and oil with parallel to the organic theory. They formed within source rock, the result of the transformation of sediments rich in organic matter that are deposited at the bottom of oceans and lakes. Over geological time, the sediments gradually became more deeply buried. During this process, they consolidated and subsurface heat and pressure converted the organic matter they contained into hydrocarbons. Most of the hydrocarbons that formed migrated up toward the surface. However, in some cases, their migration was blocked by an impermeable rock barrier under which the hydrocarbons gathers. Eventually, a conventional oil and/or gas reservoir forms (Total, 2013). Shale gas refers to natural gas that is trapped within shale formations (EIA, 2013).

After the recent production boom in the USA, shale gas has emerged as a game changer and has taken the media interest. Possesing more economically recoverable reserves among the other unconventional gas resources and spreading all over the world, both in the developed economies but also in the territories of the developing countries are important factors putting shale gas on the agenda of the global natural gas market. These are why this study focuses on shale gas as the unconventional gas resource. Detailed information about the shale gas fact wil be given in the following parts of the study.

2.2. Shale Gas; What’s and why?

Shale, consisting mainly of consolidated clay-sized particles, is one of the Earth’s most common sedimentary rock types, having ultralow permeability. In many oil fields, shale forms the geologic seal that withholding the hydrocarbons within producing reservoirs, preventing them from escaping to the surface (Frantz and Jochen, 2005).

Although it is very difficult to treat, most shale gas is fairly clean and dry. Thermally mature shales have had enough heat and pressure to produce hydrocarbons. The most thermally mature shales comprises only dry gas. While less mature shales are containing wetter gas, the least thermally mature shales contain only oil. In rare cases, small percentages of carbon dioxide, nitrogen, ethane, and even propane can be found in produced gas (Frantz and Jochen, 2005).

The first commercial shale gas well was drilled in 1821, only 27 ft below the surface in the Devonian Dunkirk shale, New York. At that times, the gas was used to only enlighten the houses. Any type of natural gas had not become an important commodity till the second half of the twentieeth century. Until recently, however, shale has been seen as only a source rock or seal for oil and gas (Frantz and Jochen, 2005). As, it is seen, although unconventional gas is nothing new to the oil and gas industry, the shale gas production is a revolution rather an progressing evolution as a combination of several old and new technological tools (Kuhn and Umbach, 2011).

The large-scale shale gas production started with Mitchell Energy and Development Corporation during the 1980s and 1990s by making it a commercial reality in the Barnett Shale of North-Central Texas. As this success emerged, some other companies aggressively showed interest in this business so that by 2005, the Barnett Shale became producing almost five hundred billions cubic feet per year. After this achievement in the Barnett Shale and positive results coming from the Fayetteville Shale in North Arkansas, more companies began running after other shale formations, like the Haynesville, Marcellus, Woodford, Eagle Ford, etc. (EIA, 2011)

With the help of the use of horizontal drilling combined with hydraulic fracturing, producing natural gas from shale formations has made an important progress. Starting in the mid-1970s, a partnership of private operators, the U.S. Department of Energy (DOE) and the Gas Research Institute (GRI) encouraged to develop technologies for the commercial production of natural gas from the relatively shallow Devonian Huron shale in the Eastern part of the country. This partnership helped promoting technologies that eventually became crucial for producing natural gas from shale rock, including horizontal wells and fracturing. Practical application of horizontal drilling to oil and gas production began in the early 1980s, when improved downhole drilling motors and the invention of other necessary supporting equipment, materials, and technologies, particularly downhole telemetry equipment, had brought some applications within the realm of commercial viability (King, 2010).

2.2.1. Technical background

As mentioned above, This combined innovation in technological progress has made it possible to access to large volumes of shale gas that were taught to be unfeasible to produce (EIA website, 2013). Seperately, both are not such new found techniques but their synthesis has driven the industry to a revolution. So, at this point giving brief information about horizontal drilling and hydraulic fracturing would be beneficial.

2.2.1.1. Horizontal drilling

Hydraulic fracturing and horizontal drilling are the primary enabling technologies behind the recent surge in effective and economic shale gas production. The first horizontal well was in the 1930's and horizontal wells were common by late 1970's (King, 2012). However, this technique of the industry came into widespread use in the mid-1990s. Horizontal drilling has been an efficient way of extracting gas from conventional reservoirs and also unconventionals like coal seams, and even from tight gas reservoirs. Now it is used to enhance recovery rates in the ultralow permeabilities like shales (Frantz and Jochen, 2005).

In order to produce the natural gas from a reservoir, typically a drill pipe is sent down vertically a distance underground and then turned at a ninety degree angle horizontally into the target shale formation. In horizontal drilling the drill cuts down vertically for up to 7,000 metres and then continues horizontally for up to 2,000 metres (Kefferputz, 2010). By using horizontal drilling, the drill bit can penetrate a much greater contact area in the formation than with vertical drilling with the help of hydraulic fracturing, explained in the mext part of the study. By using this technology, the drill bit can touch a much greater number of pockets of natural gas. According to industry results, horizontal wells produce, on the average, three to five times of the amount of natural gas that vertical ones do.

Horizontal well drilling has progressed from an art to a science. Instead of drilling straight down into the target formation, horizontal drilling enables sideways movement, opening up a much larger area of the resource and, therefore, a greater length of the shale gas deposit to be in contact with the well bore (Kuhn and Umbach, 2011). An illustrationabout the horizontal wells can be seen on the figure below.

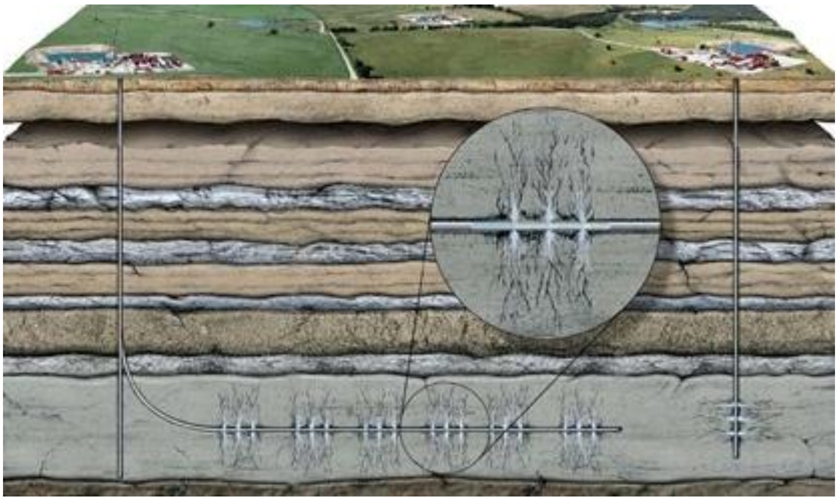

Figure 3: Vertical vs. Horizontal Drilling (Farming Magazine website, 2013).

Also, it is detected that six to eight horizontal wells drilled from only one well pad can access the same reservoir volume as sixteen vertical wells. Using multi-well pads can also significantly reduce the overall number of well pads, access roads, pipeline routes, and production facilities required, thus minimizing habitat disturbance, impacts to the public, and the overall environmental footprint (DOE, 2009).

As it is stated above, there are a wide range of factors that influence the choice between a vertical or horizontal well. However, these advantages has a price for the companies. A vertical well may cost as much as $800,000 (excluding pad and infrastructure) to drill compared to a horizontal well that can cost $2,5 million or more (excluding pad and infrastructure). Horizontal wells may require more capital investment on well basis, but production is often more efficient and economical (DOE, 2009).

2.2.1.2. Hydraulic Fracturing

The other technological key to a economically feasible recovery of shale gas is hydraulic fracturing, which can be defined as the pumping of a fracturing fluid into the shale formation in target under high pressures to fissures to maintain the gas flow through well bore. This method makes gas to go out of the rock to the well in economic quantities. Ground water can be protected during the shale gas fracturing process by a successfull casing and cementing design. Fracture fluids are primarily water based mixed with additives that help the water to carry sand proppant into the fractures. Water and sand make up over 98% of the fracture fluid, and the remaining 2% consists of various chemical additives that improve the effectiveness of the fracture job (US DOE, 2009).

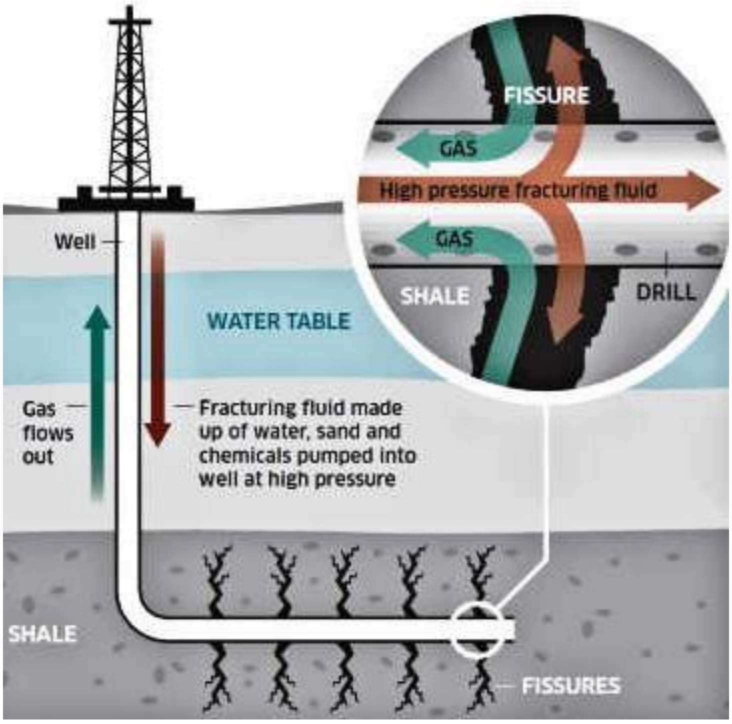

Figure 4 : Hyraulic Fracturing (Suffol University website, 2013).

In addition to water and sand, other additives are used to allow hydraulic fracturing to be performed in a safe and effective manner. This fluid is injected into deep shale natural gas or oil formations and is typically confined by many thousands of feet of rock layers. Additives used in the fluid may include many compounds also can be found in common consumer products. Table 1 is giving detailed information about the most used ingredients of fracturing fluids

Table 1: Additives used in fracturing fluids (Chesapake Energy, 2010).

Product	Purpose	Downhole Result	Other Common Uses
Water and Sand: ~ 98%			
Water	Expands the fracture and delivers sand	Some stays in the formation, while the remainder returns with natural formation water as produced water (actual amounts returned vary from well to well)	Landscaping and manufacturing
Sand (Proppant)	Allows the fractures to remain open so that the natural gas and oil can escape	Stays in the formation, embedded in the fractures (used to "prop" fractures open)	Drinking water filtration, play sand, concrete and brick mortar
Other Additives: ~ 2%			
Acid	Helps dissolve minerals and initiate cracks in the rock	Reacts with the minerals present in the formation to create salts, water and carbon dioxide (neutralized)	Swimming pool chemicals and cleaners
Anti-bacterial Agent	Eliminates bacteria in the water that produces corrosive by-products	Reacts with micro-organisms that may be present in the treatment fluid and formation; these micro-organisms break down the product with a small amount returning to the surface in the produced water	Disinfectant; sterilizer for medical and dental equipment
Breaker	Allows a delayed breakdown of the gel	Reacts with the crosslinker and gel once in the formation, making it easier for the fluid to flow to the borehole; this reaction produces ammonia and sulfate salts, which are returned to the surface in the produced water	Hair colorings, as a disinfectant and in the manufacture of common household plastics
Clay Stabilizer	Prevents formation clays from swelling	Reacts with clays in the formation through a sodium-potassium ion exchange; this reaction results in sodium chloride (table salt), which is returned to the surface in produced water	Low-sodium table salt substitutes, medicines and IV fluids
Corrosion Inhibitor	Prevents corrosion of the pipe	Bonds to the metal surfaces, such as pipe, downhole; any remaining product that is not bonded is broken down by micro-organisms and consumed or returned to the surface in the produced water	Pharmaceuticals, acrylic fibers and plastics
Crosslinker	Maintains fluid viscosity as temperature increases	Combines with the breaker in the formation to create salts that are returned to the surface in the produced water	Laundry detergents, hand soaps and cosmetics

Table 1 (continued)

Friction Reducer	"Slicks" the water to minimize friction	Remains in the formation where temperature and exposure to the breaker allows it to be broken down and consumed by naturally occurring micro-organisms; a small amount returns to the surface with the produced water	Cosmetics including hair, make-up, nail and skin products
Gelling Agent	Thickens the water to suspend the sand	Combines with the breaker in the formation, making it easier for the fluid to flow to the borehole and return to the surface in the produced water	Cosmetics, baked goods, ice cream, toothpastes, sauces and salad dressings
Iron Control	Prevents precipitation of metal in the pipe	Reacts with minerals in the formation to create simple salts, carbon dioxide and water, all of which are returned to the surface in the produced water	Food additives; food and beverages; lemon juice
pH Adjusting Agent	Maintains the effectiveness of other components, such as crosslinkers	Reacts with acidic agents in the treatment fluid to maintain a neutral (non-acidic, non-alkaline) pH; this reaction results in mineral salts, water and carbon dioxide – a portion of each is returned to the surface in the produced water	Laundry detergents, soap, water softeners and dishwasher detergents
Scale Inhibitor	Prevents scale deposits downhole and in surface equipment	Attaches to the formation downhole with the majority of the product returning to the surface with the produced water, while the remaining amount reacts with micro-organisms that break down and consume it	Household cleansers, de-icers, paints and caulks
Surfactant	Increases the viscosity of the fracture fluid	Returns to the surface in the produced water, but in some formations it may enter the natural gas stream and return in the produced natural gas	Glass cleaners, multi-surface

2.2.2. Global shale gas activities by regions

In this part of the study, the history of the shale gas production, reserve stimates and exploration and production activities in the important shale plays are examined globally and region by region. Firstly, North America, as the pioneer of shale business, then Europe, which is the second important economy that can be rejuvenated by the utilization of its shale reserves and lastly the other important regions in the world, like China, Australia, South America etc. will be analysed respectively.

2.2.2.1. North America

2.2.2.1.1. A tale of success: shale gas revolution

It is necessary to study the North American unconventional gas revolution as a starting point because it is the only place today that making substantial production from unconventional gas resources, following a long and uneven path of developments (Geny, 2010).

The growth in unconventional gas exploration in the U.S. in the last decade was initially driven by the high gas prices of 2005-2008 (Kuhn and Umbach, 2011). As it is stated in previous sections, the first commercial shale gas well was drilled in 1821 and few production was done during almost two centuries. Until recent decade, shale has been seen as only a source rock or a seal, however it is now regarded as a game changer in the global gas market with the important production amounts mostly in North America.

It is in the United States that unconventional gas has really taken off in recent years and there are a number of factors have come together that created a major push to develop the resources.

Firstly, there now exists a great deal of geological knowledge. In many cases unconventional reservoirs overlie conventional deposits, many of which have been extensively explored. This provides a good reference for drilling locations according to the earlier measurements about the unconventional plays. Often conventional wells explore below the initial find and this can also provide data on shale plays below conventional deposits.

Secondly, in 1980, the Crude Oil Windfall Profit Tax Act introduced an alternative fuel production tax credit of $3 per BTU oil barrel – 53 cents per thousand cubic feet (tcf) – under the Section 29 Credits of the Act. This credit, which remained in force until 2002, was a function of the price of oil. To reduce the incentive to switch from unconventional gas to oil products when oil prices fell, a decline in oil price was matched by an increase in the tax credit. Given that after 1980, the wellhead price rarely exceeded $2 tcf, this was a significant incentive to attempt to develop unconventional gas. After 2000 prices began to rise, further encouraging gas production.

The technological developments with horizontal drilling and hydraulic fracturing, were a third major factor in the American story. For example, in 2004, 490 of the 920 wells in the Barnett Play were vertical. By 2008, as many as 2,600 of the 2,710 wells were horizontal (IEA, 2009).

One other factor backing the shale gas boom in the US is that unconventional gas operations are free of restricting regulations on both state and federal basis. The best example at this point is the exemption for hydraulic fracturing from the Safe Drinking Water Act by the Energy Policy Act of 2005 (Hines, 2012) .

The last but not the least is the existence of a dynamic service sector, adequate technologial equipments and experienced labour of both white-collars and blue-collars. A dynamic and competitive service industry is able to respond to the interests of the operators. The major part of the drilling rigs suitable for horizontal drilling and hydraulic fracturing in the world is in operation in the United States. Also the know-how of labour for unconventional gas operations is mostly working in this country (Stevens, 2010).

2.2.2.1.2. Reserves

The United States is the country that having the most prominent shale gas reserves. It is known that shale formations are present across much of the lower 48 states. However, most active shales to date are the Barnett Shale, Fayetteville Shale, Haynesville Shale, Marcellus Shale, Woodford Shale, Antrim Shale, New Albany Shale plays.

Regarding to the technically recoverable reserves, the biggest shale play in the US is Marcellus. After Marcellus, Haynesville, Barnett, Fayetteville, Antrim, New Albany and Woodford shale plays are the other important shale plays respectively (DOE, 2009).

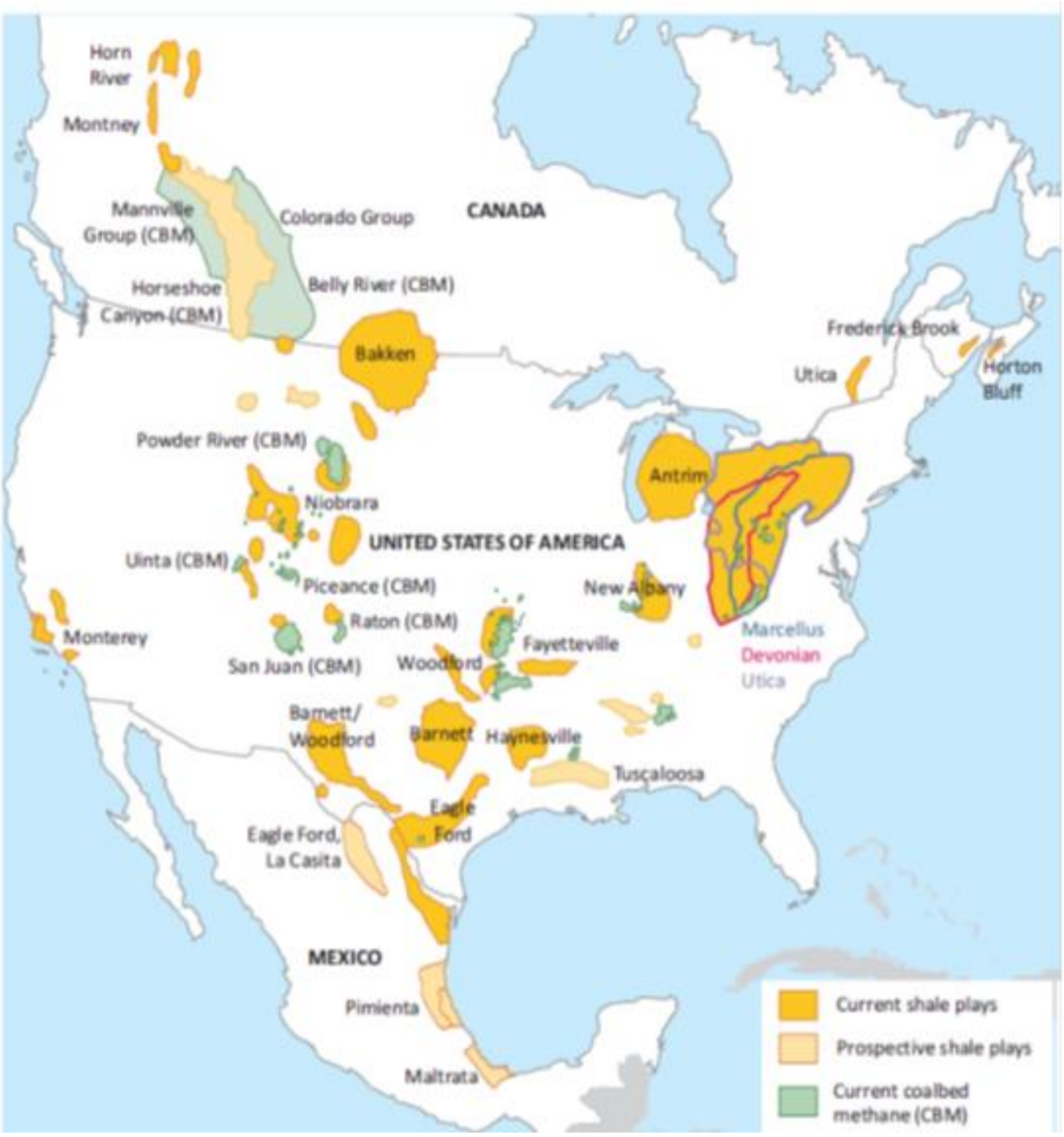

Figure 5: North America Shale Plays (IEA, 2012).

The most recent released estimation of Energy Information Administration, Department of Energy demonstrates that the total original gas in place is over 2800 Tcf (trillion cubic feet at 14.73 psia and 60 degree Fahrenheit) and technically recoverable gas is 650 Tcf in 2009 (DOE, 2009) and 97,5 Tcf proven reserves in 2010 (EIA website, 2013) only in these 7 active shale plays of the United States, the Barnett Shale, Fayetteville Shale, Haynesville Shale, Marcellus Shale, Woodford Shale, Antrim Shale, New Albany Shales in 2009. The specific technical properties of these prominent shale plays are as follows.

Table 2 : Comparison Data for The Shale Gas Shales in the United States (DOE, 2009)

Gas Shale Basin	Barnett	Fayetteville	Haynesville	Marcellus	Woodford	Antrim	New Albany
Estimated Basin Area, square miles	5,000	9,000	9,000	95,000	11,000	12,000	43,500
Depth, ft	6, 500 - 8,500	1,000 - 7,000	10,500 - 13,500	4,000 - 8,500	6,000 - 11,000	600 - 2,200	500 - 2,000
Net Thickness, ft	100 - 600	20 - 200	200 - 300	50 - 200	120 - 220	70 - 120	50 - 100
Depth to Base of Treatable Water*, ft	~1200	~500	~400	~850	~400	~300	~400
Rock Column Thickness between Top of Pay and Bottom of Treatable Water, ft	5,300 - 7,300	500 - 6,500	10,100 - 13,100	2,125 - 7650	5,600 - 10,600	300 - 1,900	100 - 1,600
Total Organic Carbon, %	4.5	4.0 - 9.8	0.5 - 4.0	3 - 12	1 - 14	1 - 20	1 - 25
Total Porosity, %	4 - 5	2 - 8	8 - 9	10	3 - 9	9	10 - 14
Gas Content, scf/ton	300 - 350	60 - 220	100 - 330	60 - 100	200 - 300	40 - 100	40 - 80
Water Production, Barrels water/day	N/A	N/A	N/A	N/A	N/A	5 - 500	5 - 500
Well spacing, acres	60 - 160	80 - 160	40 - 560	40 - 160	640	40 - 160	80
Original Gas-In-Place, tcf[127]	327	52	717	1,500	23	76	160
Technically Recoverable Resources, tcf[128]	44	41.6	251	262	11.4	20	19.2

Other than the USA, Canada and the Mexico are the other shale gas holder countries in the continent.

The gas-bearing shales of Canada are concentrated in Alberta and British Columbia of Western Canada and in Quebec, Nova Scotia and New Brunswick of Eastern Canada (Dawson, 2010). The risked gas in place is nearly 1500 Tcf and the technically recoverable resources are 388 Tcf among the country (EIA, 2011).

In Mexico, thick, organic-rich and thermally mature source rock shales occur in northeast and east-central Mexico, along the country's onshore portion of the Gulf of Mexico Basin. These shales are Eagle Ford, Haynesville, Bossier and Pearsall shales. Advanced Resources (ARI) estimated that the five Mexico onshore basins assessed in this study contain approximately 2,366 Tcf of geologically risked shale gas in-place. An estimated 681 Tcf (risked) is judged to be technically recoverable (EIA, 2011).

2.2.2.1.3. Exploration and production activities

At the current situation, the seperate share of the shale gas in total natural gas production is 34% with 8,13 Tcf while the share of the unconventional gas in the total domestic natural gas production is 65% with 15,6 Tcf in 2012 (Siemenski, 2013).

The first serious commercial flows began in 1981 and by the late 1990s the Barnett Play was producing 13 bcm. In 2002, the first horizontal well was drilled on this play and by 2009 it was producing 76 bcm, over 11% of total US gas production. The technology has been developing quickly. It took the Barnett Play 20 years to achieve 5 bcm while the Fayetteville Play reached this level in 4 years (Stevens, 2010). Experience and information gained from developing the Barnett Shale have improved the efficiency of shale gas development around the country.

There are several companies dealing with the shale gas business especially in the United States. Many of them are small and middle scale companies that have become popular and have grown with their shale gas production like Devon Energy, Chesapeake Energy, and XTO Energy. Also there are some international and multinational oil companies that are taking part in the American shale business by both greenfield investments and brownfield investments by acquiring American companies or purchasing their leases or licences.

Table 3 demonstrates the top 25 shale gas players in the USA, their names, reserves and productions.

Also, while the production level of Canada is far less than the USA, Nexen, the joint venture of Penn West Energy Trust and Mitsubishi, Talisman and Forest Oil, some other smaller companies such as Questerre, JunexTriangle Petroleum and Forent Energy are some of the operational companies in Canada (EIA, 2011).

On the other hand, despite the proximity between the American and Mexican shale plays, there is not any shale gas exploration drilled yet. It is known that the national oil company of country, PEMEX is planning to drill an exploration well in the Eagle Ford Shale (EIA, 2011).

Table 3: Top 25 Shale Gas Players in the USA (Sasarean, 2011)

Quote Symbol	Company Name	Estimated US Natural Gas Reserves (Bcf)	Natural Gas Production (mmcf/d)*	Estimated Shale Gas Share in Overall O&G Production
XOM	Exxon (XTO)	26,100	3,873	0 to 20%
CHK-N	Chesapeake Energy Corporation	15,455	2,639	75 to 100%
APC-N	Anadarko Petroleum Corporation	8,100	2,369	0 to 20%
DVN-N	Devon Energy Corporation	9,000	1,997	50 to 75%
BP_GB	British Petroleum (BP)	13,700	1,869	0 to 20%
ECA-N	EnCana Corporation	7,500	1,833	75 to 100%
COP	ConocoPhillips	10,500	1,621	0 to 20%
SWN-N	Southwestern Energy Company	4,345	1,312	75 to 100%
CVX	Chevron (Atlas)	2,500	1,284	0 to 20%
EOG-N	EOG Resources, Inc.	6,861	1,124	50 to 75%
RDSA_GB	Royal Dutch Shell (East)	4,502	953	0 to 20%
APA-N	Apache Corporation	4,340	869	0 to 20%
HK-N	Petrohawk Energy (BHP Billiton)	3,392	792	75 to 100%
OXY	Occidental	Not Reported	748	0 to 20%
QEP-N	QEP Resources Inc.	2,612	641	50 to 75%
UPL-N	Ultra Petroleum Corp.	4,200	614	75 to 100%
NFX-N	Newfield Exploration Company	2,490	510	20 to 50%
EQT-N	EQT Corporation	5,200	464	50 to 75%
COG-N	Cabot Oil & Gas Corporation	2,644	439	75 to 100%
RRC-N	Range Resources Corporation	4,442	346	75 to 100%
PXD-N	Pioneer Natural Resources Company	2,594	331	75 to 100%
XEC-N	Cimarex Energy Company	1,254	326	20 to 50%
TLM-T	Talisman Energy Inc	5,240	315	20 to 50%
PXP-N	Plains Exploration & Production Company	1,157	285	20 to 50%
HES	Hess Corporation	568	103	0 to 20%

2.2.2.2. Europe

When the fact that unconventional gas resources are estimated to be five times those of conventional gas (Stevens, 2010) is taken into consideration, unconventional gas accounts in the projections of International Energy Agency for nearly half of the increase in global gas production to 2035 (IEA, 2012).

With this importance of the new shale gas discoveries, the possible replication of this revolution has started to be talked all over the world, especially Europe after the successful story of shale gas production boom in the U.S. It is known that this continent is one of the biggest natural gas consumers in the world and dependent on the imports mainly from Russian Federation by pipeline and a few countries by LNG beside its domestic production which is insufficient to meet the consumption with a ratio of slightly under 40%.

In this section of the study, the question whether Europe can replicate the shale gas revolution of the U.S. will be tried to be answered, and then the shale gas reserves and the exporation and production activities in the continent will be analyzed.

2.2.2.2.1. Can Europe replicate America's revolution?

Many policy makers and energy companies have already Show interest on the shale gas production in Europe throughout the continent. They aim to repeat the American shale gas revolution. Although it is estimated that there are important shale plays, detailed information about those are given in the next part of this section, the exploitation of these reserves can be regarded as questionable. At this point, there are some obstacles that can hinder to convert the reserves to money. To state, those are landholding and public acceptence, water management, lack of geological information, industrial competence and financial requirements.

Firstly, legal landholding conditions in Europe are totally different form the U.S. In the U.S., the owner of the land also owns the subsoil rights and receives revenues from the resources exploited underground. This provides an important incentive to landowners to allow gas drilling and production on their land. Conversely, in most European countries, the state owns the rights and receives royalties. The owner of the land does not own the underground rights and E&P companies must therefore negotiate with the subsoil owner – the state in most cases – and the land owner, which makes the process far more knotted. This has two major implications for public opinion. Firstly, because landlord does not become lucrative, the possibility of approving is reduced. Also, the local opposition to drilling activities from an environmentally more sensitive European public is quite possible if it cannot get any profit from their underground properties (Kuhn and Umbach, 2011). In addition, it is a fact that Europe is densely populated and highly urbanized nearly three times of America. Unfortunately, the shale plays are generally located in the densely populated urban areas in Europe. When the fact that unconventional gas development needs larger areas up to ten times of conventional production is taken into account, largescale unconventional gas operations will strike on residential areas and people will intend to oppose to operations. (Stevens, 2010). However, with the tecnological improvements in drilling and reservoir management, it is thought that this handicap can be removed by time.

Second obstacle is the water management which can be analyzed in the categories of water contamination due to fracturing and the water scarcity caused by drilling operations. Many sociological reearches reveals that European society is more sensitive about environmental issues than the Americans. The lack of public acceptance as a result of the popular debate about the groundwater contamination caused by fracturing and the legal restrictions in drilling and fracturing operations in many European countries appear to be a serious handicap for European shale gas operations. However, it should be remembered that, there was no documented contamination case due to transfer of fracturing chemicals to any fresh water aquifer or to the surface from a zone deeper than 2000ft with proper well construction. Cases of suspected contamination by chemicals in shallower zones are known to be linked to poor isolation of the well during the well construction phase (King, 2012). Also, as it is known, unconventional gas production needs huge amounts of water to fracture the formation. According to the IEA estimates, 4–5 million gallons are needed to stimulate only one well (IEA, 2009). Providing such large quantities of water in regions where water is insufficient will be an obstacle to develop shale gas projects. However, today it is known that 70% of fracturing water can be re-used in most shale plays. Therefore the necessary amount of watercan be reduced. In addition, where fresh water could not be provided, technological improvements now make it possible to use salty water (Kuhn and Umbach, 2011).

The third problem is the lack of the sufficient geological information about the European shale plays. A major potential problem in Europe is that the geology for shale gas is much less promising than in the United States. The plays are more rended and the shale is richer in clay, making European resources less compatible to stimulation. Furthermore, they lack the history of drillling measurements that exists in the United States, since onshore drilling in the Western Europe has been much more limited (Stevens, 2010).

Another obstacle is the quality of the industrial infrastructure in Europe. The existence of a dynamic and competitive service sector abundant industrial technology and equipments were substantial supports of the American revolution. In World Energy Outlook 2009, IEA estimated for Western Europe to produce 1 tcf of shale gas over 10 years (around 5% of total gas consumption in Western

Europe) would require around 800 wells per year to be drilled. However, as of April 2010 there appeared to be only around 100 land rigs, even most of them are not suitabe for unconventional operations, in Western Europe, compared with 2.515 active rigs in the United States in 2008, of which 379 were in oil and 1,491 in gas (Stevens, 2010). If the American revolution is wanted to be imported, also the dynamic sectoral structure is to be imported.

The last but not the least is the financial situation of the European gas markets. The breakeven prices of the shale gas production would be very higher than the American shales due to the higher drilling & completion costs, European gas imports, etc. According to the Oxford Institute for Energy Studies, the cost of producing shale gas in Europe will be up to 4 times the one in U.S. where costs of production are in the range of $2 and $6 or $7, which means costs of $8 to $27 per mmbtu in Europe (Geny, 2010). So, shale gas production would be an expensive case, but the European gas market structure with high and stable oil-linked prices, important shale plays will probably make producer companies happy.

The detailed comparison and differences between the U.S shales and the European shales are summarized in Figure 6.

U.S. shale	European shale
Much domestic gas production	Dwindling & limited domestic production
Many effective hubs	Few hubs
Many interstate pipelines	Few integrated market players
Many integrated energy companies, market players	Landscape dominated by National regulators, not Federal regulator
Strong federal Regulator	Higher initial cost
Infrastructure, Service companies & suitable drilling rigs	Well & production cost are higher
Vast Geologic formations / plays	Higher depths of the reserves
Property rights	Varying geologic formations / plays
Landowners	Technique needs to developed and adapted
Lower population	Property / land rights owned by state
Liberalized market	Local community profits from drilling?
Access to trading hubs & pipelines	Public opinion of drilling (NIMBY)
Spot traded commodity	Dense population
	Surface footprint of unconventional gas
	Missing service industries & drilling rigs
	Market structure liberalization & deregulation
	Long-term contracts
	Few integrated market players

Figure 6 : Comparison of U.S. and European shale possibilities (Kuhn and Umbach, 2011).

Wood Mackenzie and Deutsche Bank reports indicate that a European shale gas boom has a low possibility. Indeed, Deutsche Bank reports do not expect unconventional gas to produce more than 9 bcm – nearly the 1% of European demand by 2020 (Kuhn and Umbach, 2011).

In sum, regardless of the achievement possiblity of affordable and sustainable shale gas production, it has already started to reshape the European energy markets; even before a single well has been drilled, or a single cubic meter of shale gas is produced from the European resources (Kuhn and Umbach, 2011).

2.2.2.2.2. Reserves

Europe is the region that having the second most prominent shale plays in the world. When the fact that the developed economies fed by natural gas in the Western side of the continent and the developing ones in the Eastern side are extremely dependent on the Russian gas isconsidered, the importance of the shale gas reserves come to the forefront.

The total estimated technically recoverable resources are 639 Tcf in the continent (EIA, 2011). The Western and the Eastern sides of the continent will be examined seperately.

In the Western Europe, France, Norway, Denmark, United Kingdom, the Netherlands and Germany are the countries that shale gas deposits lay under their soils with technically recoverable resources of 180, 83, 23, 20, 17 and 8 Tcf, respectively. The total resources of the Western Europe is 372 Tcf (EIA, 2011)

The largest basin is the North Sea-German Basin which comprises of Posidonia, Namurian and Wealden Shales. After that, France Paris Basin is the second largest basin with its Permian-Carboniferius Shale formation. Scandinavia Region comprising of Alum Shale, UK Northern Petroleum System with Bowland Shale, France South-East Basin comprising Terres Noires and Liassic Shales and UK Southern Petroleum System comprising Liassic Shale formations are the other shale plays.

The countries having shale gas resources are Poland, Ukraine, Turkey, Lithuania and others (Romania, Hungary and Bulgaria) with amounts of 187, 42, 15, 4 and 19 Tcf, respectively. Poland has the biggest reserves with 187 Tcf both in the Eastern side of 267 Tcf and the whole continent of 639 Tcf. The Lower Silurian Shale Formation lies through the Baltic, Lublin and Podlasie basins.

Outside of Poland, the shale gas potential of Eastern Europe has not been widely explored. However, several basins are considered to have shale gas targets, such as the northern Baltic Basin in Lithuania, the Lublin Basin into Ukraine and the Dnieper-Donets Basin in Ukraine. Additional potentially prospective basins are the Pannonian-Transylvanian Basin in Hungary and Romania, and the Carpathian-Balknian in Southern Romania and Bulgaria (EIA, 2011).

Rather than the other European countries, more detailed information about the reserves of Turkey will be given in the prospective chapter of the study.

2.2.2.2.3. Exploration and production activities

Poland is the most active country that holding shale gas exploration and production activities besides having the biggest reserves among the Europe. There are many energy companies taking part in the Polish shale gas business either performing seismics, drilling wells or having licences and prospects for future plans. Those are national gas entity PGNiG, International Oil Companies like Marathon Oil, ConocoPhilips, BNK Petroleum, ENI and smaller companies like 3 Legs Resources (a subsidiary of Lane Energy Poland), Talisman Energy, Realm Energy International, San Leon Energy, etc.

As of April 2012, seventeen wells have been drilled, two of them horizontal, with several drilling operations underway (Talisman Energy, ENI). The two horizontal wells and a handful of vertical wells had been hydraulically fractured. Cores of shale rock are currently been examined by geochemists in laboratories in the USA and Canada. According to industry officials, the first findings are ‘‘very promising,’’ but there are also important indications from 3 Legs and BNK Petroleum that drilled wells in Poland (Bloomberg News website, 2013). A handicap is the underdeveloped gas and oil service industry that is present in Poland with a few drilling rigs. Moreover, there is no clear indication yet whether the economic and political conditions in Poland will be favorable enough for industry players to justify further exploitation of this resource (Johnson and Boersma, 2013).

In Eastern Europe, outside of Poland, Lithuanian government has declared that they are aware of their shale gas potential. Also, Estonian shale gas resources' development plans are underway. Also, Shell, ExxonMobil and a joint venture between Eurogas and Total have interests and operations in Ukraine. Also in Romaina and Bulgaria, Chevron has some activities.

In Western Europe, shale gas activities are slower than the Eastern side due to legal restricts and some other concerns. Nevertheless, there are many energy companies having interest on the prospects of the countries. French government has granted many licences for its through their country to companies like Total, GSF Suez, Devon Energy and many other small companies. In Germany, the leading company is Exxon Mobil with some exploration wells drilled, BNK Petroleum and 3Legs Resources with 2D and 3D seismics and some drilled exploration wells. In the Netherlands, TAQA (Abu Dhabi national energy company) and BG Group have licences but there is not any serious activity about the shale reserves. In Scandinavian region, the most active company is Shell with drilled exploration wells and in UK, also companies like Celtique, Cuadrilla, Island Gas has licences and future plans for shales in Northern and Southern Petroleum Systems (EIA, 2011).

2.2.2.3. Rest of the world

Besides America, the pioneer of the shale gas business and its slower follower Europe, also there are some other regions and countries that have serious shale gas activities like China, India, Australia and the Latin American countries.

2.2.2.3.1. Reserves

China has the biggest amount of technically recoverable shale gas resources in the world, even more than the U.S. with 1275 Tcf. Also, in Asian region India has a resource of 63 Tcf and Pakistan has a resource of 51 Tcf.

China has two large sedimentary basins that contain thick, organic-rich shales with important potential for shale gas development. These two basins are the Sichuan and the Tarim. Since the shale drillings have recently started, public information on shale formations in China is quite limited. But, the future of shale gas development in China is promising, though it seems likely that five to ten years will be needed before sufficient production. Also, it is known that some Chinese companies acquiring some mid scale American companies to get the right to take part in American market. In Asia-Pacific region, India and Pakistan are the other countries that are having fairly well shale gas resources (Bloomberg News website, 2013).

India and Pakistan contain a number of basins with organic-rich shales. For India, there are four priority basins: Cambay, Krishna Godavari, Cauvery and the Damodar Valley sub-basins such as Raniganj, Jharia and Bokaro. Also, there arae some other basins of India, such as the Upper Assam, Vindhyan, Pranhita-Godavari and South Rewa, but found that either the shales were thermally too immature for gas or the sufficient data about them is not available. For Pakistan, there is one priority shale gas basin, Southern Indus (EIA, 2011).

Alongside of its extensive CBM and tight gas reserves, Australia has also important amount of shale gas resources. The magnitude of the gas in these shale basins that can be technically recoverable is 396 Tcf. With geologic and industry conditions resembling those of the USA and Canada, the country intends to commercialize its gas shale resource. There are four main shale basins: Cooper, Maryborough, Perth and Canning Basins (EIA, 2011).

Although resources in the Latin America countries like Chile, Paraguay, Bolivia and Uruguay are much less than the huge basins in Argentina and Brazil, 774 and 226 Tcf respectively, but still are more than many European countries with the magnitude of 64, 62, 48 and 21 Tcf, respectively (EIA, 2011).

2.2.2.3.2. Exploration and production activities

In China, the center of the industry on the shale gas exploration activities is Sichuan Basin with its favorable reservoir quality, including prospective thickness, depth, TOC, thermal maturity. Alongside of the national companies of China, PetroChina and Sinopec, major oil companies like Shell, Chevron, ConocoPhilips and some other companies like EOG Resources and Newfield Exploration have exploration rights in the basin. As the country have the biggest reserves in the world, the dynamism of the E&P acitivities can be regarded as the second in the world after the U.S. However, the most important problem in the sector is the lack of expertise. To solve this problem, companies have signed agreements with foreign specialist service companies like Schlumberger and Halliburton for the hydraulic fracturing technology. The first results of the exploration wells in the basin are promising and investment worths billions of dollars are planned in the country (Cnbc website, 2013). Other than China, it can be said that there is not serious activity in other Asian countries like India and Pakistan.

Initial shale explorations are under development in Argentina's Neuquen Basin, led by Apache Corporation and YPF (Repsol). (Apache Cosp. Website, 2013). Also, Apache and Repsol have extensive 3D seismic coverage in the basin. On the otherhand, there is not substantial exploration activity in the northern part of the continent. However, a good gas potential is reported from the first tests of the La Luna formation by a well drilled by Ecopetrol. Although this potential is estimated for conventional gas resources, this may also be interpreted for the unconventional resources in the same formation (EIA, 2011).

CHAPTER 3

THE SHALE GAS POTENTIAL IN TURKEY

"Turkey is one of the luckiest countries for shale gas in terms of its soil structure, TransAtlantic Petroleum's country manager Selami Uras told Reuters (Reuters website, 2013). While, Shale development is progressing slowly in Europe, where Poland and Britain also have plans, Turkey's low taxes, existing oil and gas infrastructure, high domestic energy demand and role as a hub for international shipping help make it attractive as a potential shale gas producer. U.S. Department of Energy, Energy Information Administration stated in its report by name “World Shale Gas Resources: An Initial Assesment of 14 Regions Outside The United States” in April 2011 that Turkey has a techically recoverable shale gas resources of 15 Tcf (425 bcm). On the other hand, some experts claim that estimation studies done by EIA held in a narrow perspective, even they did not go out of the limits of the currently producing conventional fields. These arguments support Turkish energy analyst Mr. Necdet Pamir told Reuters, “In shale gas, you have to dig lots of wells to determine the amount of reserves, it's still too early to make forecasts, but it's said that 1.8 trillion cubic metres of shale gas exists in southeast and northwest Turkey, which is a significant amount.” (Reuters website, 2013) Also, if the facts that these forecasts are evaluated for only the southeastern and northwestern Turkey and according to the first results of the surveys conducted in the Central Anatolian Region reveals that there may probably exist shale gas deposits in Ankara, Kırşehir and Konya (Mr. Taner Yildiz, the Minister of Energy and Natural Resources, 2013) are taken into consideration, it is quite likely that Turkey will be shale gas rich country provided the necessary investments are made.

3.1. Potential Reserves and Reservoir Characterization.

It is known that there are two main shale gas basins in Turkey, the Thrace Basin in western Turkey and the Southeast Anatolia Basin along the border with Iraq and Syria. These two basins are under active shale and conventional gas exploration by the Turkish national petroleum company, TPAO, and some other international exploration companies.

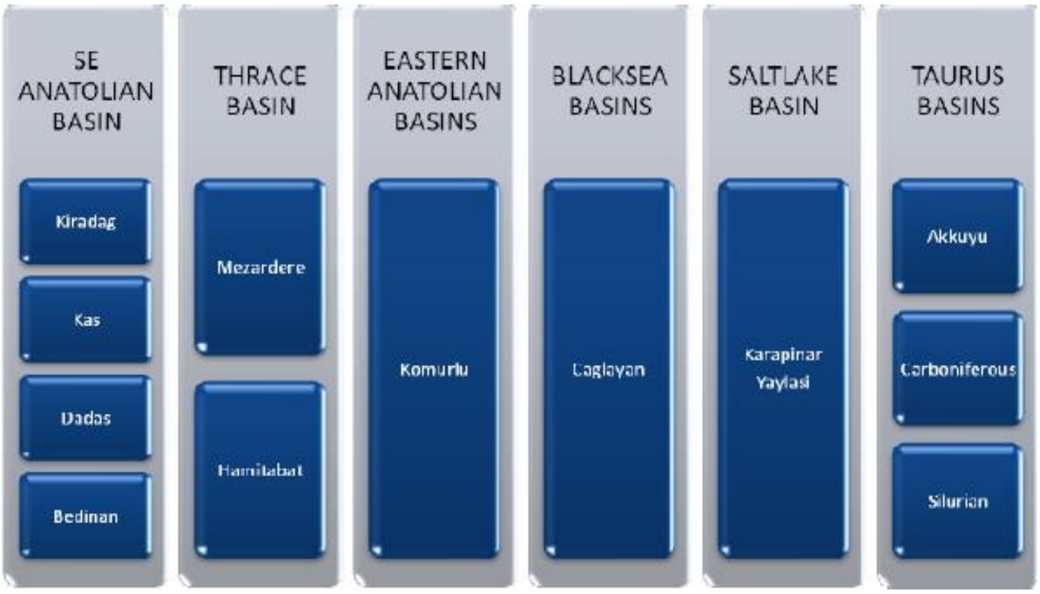

Figure 7 : Potential unconventional formations in different basins of Turkey (TPAO website, 2013).

Turkey may also have shale gas potential in the interior Saltlake – Sivas, Aegean, Eastern, Taurus basins and some others, as well as the onshore portion of the Black Sea Basin. However, because detailed reservoir data on shale formations in these basins is not readily available, their shale gas resource potential has not been assessed. The main shale plays, as the basins and geographical regions, and the seismic data gathered in Turkey are shown in the figures below.

Figure 8 : The shale plays in Turkey (Bahtiyar, 2013).

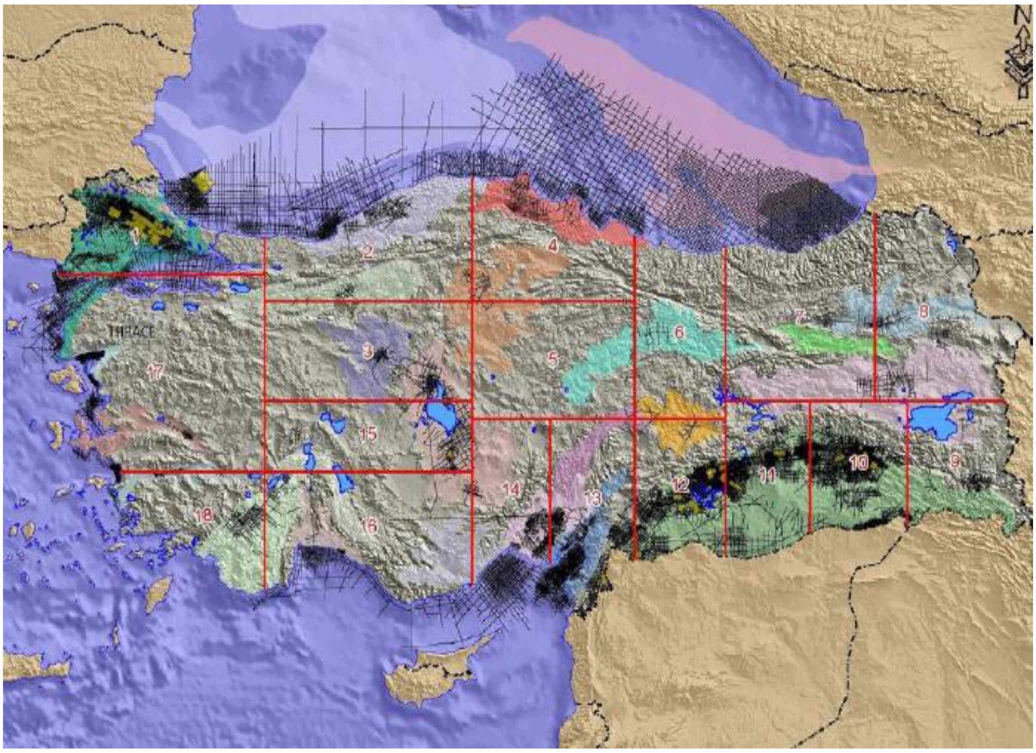

Figure 9 : The seismic data gathered in Turkey (Bahtiyar, 2013)

As stated previously, ARI (Advanced Research Institute) estimates for EIA that the Thrace and SE Anatolian basins contain 64 Tcf of risked gas in place from three prospective shale formations. These formations contain an estimated 15 Tcf of technically recoverable shale gas resource (EIA, 2011).

Table 4 : Reserves and Reservoir Properties of Turkish Shale Formations (EIA, 2011).

Basic Data	Basin/Gross Area		SE Anatolia Basin (32,450 mi²)	Thrace Basin (8,586 mi²)	
	Shale Formation		Dadas Shale	Hamitabat	Mezardere
	Geologic Age		Devonian-Silurian	Mid-Lower Eocene	Lower Oligocene
Physical Extent	Prospective Area (mi^2)		2,950	312	303
	Thickness (ft)	Interval	328 - 1,300	3,280 - 8,200	1,640 - 8,200
		Organically Rich	500	1,722	1,476
		Net	150	344	295
	Depth (ft)	Interval	6,560 - 9,840	12,136 - 16,400	8,200 - 10,168
		Average	8,200	14,268	9,184
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal
	Average TOC (wt. %)		5.5%	3.9%	2.5%
	Thermal Maturity (%Ro)		1.10%	1.75%	1.10%
	Clay Content		Medium	Medium	Medium
Resource	GIP Concentration (Bcf/mi^2)		61	128	74
	Risked GIP (Tcf)		43	14	7
	Risked Recoverable (Tcf)		9	4	2

As the only basins that the necessary seismic data exist are Thrace and SE Anatolian basins, the geological characterization and the reservoir properties about Turkish shale plays that are examined in this study are about these two.

3.1.1. The Thrace Basin

There are two different potential formations in the gas-prone Thrace Basin, Hamitabat and Mezardere formations. These formations and their geochemical properties are given below according to their maximum values obtained from the core&cuttings (Aydemir, 2010);

Mid - L. Eocene Hamitabat Formation:

- Thickness: 1500 m
- TOC: 1.54 - 6.37%
- S_1 +S_2: 230 - 39860
- T_{max}: 412 - 438 ^oC

L. Oligocene Mezardere Formation:

- Thickness: 2000 - 2500 m
- TOC: 1.00 - 4.06%
- S_1+S_2: 30 - 12490
- T_{max}: 437 - 445 ^oC

TOC refers to Total Organic Content. S_1 is the integral of the first hydrocarbon peak produced by heating the rock sample in flowing helium at 250" C for 5 minutes (or from 50 to 325' C at 40 C/min in the case of the MP-3 analysis). S_1 is free or adsorbed hydrocarbons in the rock. S_2 is the integral of the second hydrocarbon peak produced mainly by pyrolysis of the solid organic matter when the rock is heated from 250" to 550" C at 25" C/min (or 325" to 720" C at 40" C/min in the case of the MP-3 analysis) (Plafker and Claypool, 1979)

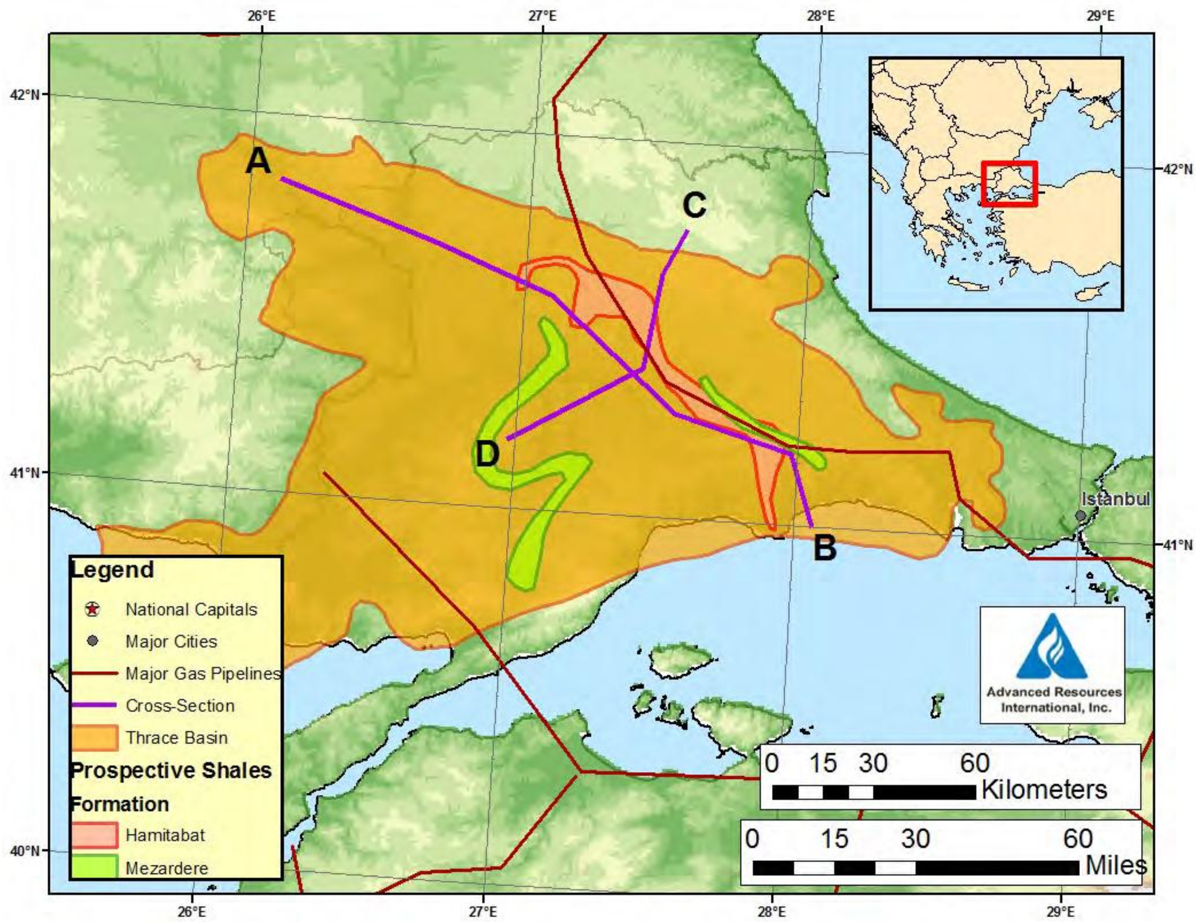

Figure 10 : Shale formations in the Thrace Basin (EIA, 2011).

Also, ARI has estimated some reservoir characteristics for the Thrace shales, shown in detail in the Table- 5, and, based on these estimations, it has calculated a shale gas resource concentration of 128 Bcf/mi^2 for the Hamitabat Shale and 74 Bcf/mi^2 activity for the Mezardere Shale within their prospective areas, the Hamitabat and Mezardere shales contain a risked gas in place of 14 Tcf and 7 Tcf, respectively. Of this, an estimated 4 Tcf could be technically recoverable in the Hamitabat Shale and 2 Tcf could be technically recoverable in the Mezardere Shale (EIA, 2011).

3.1.2. Southeast Anatolian Basin

This Basin spreads a large, 32,450 mi2 area of the Arabian plate inside the Turkish border.It is bounded on the northern part by the Zagros suture zone, which marks the juncture of the Arabian and Eurasian tectonic plates. The basin covers an area similar to the size of the Barnett Shale.

There are four different formations in the Southeast Anatolian Basin, namely Bedinan, Dadas, Kas, and Kiradag. Among those, Devonian – Silurian Dadas formation is the most promising one in terms of having potential shale gas reserves. Such that, ARI calculated a moderate gas in-place resource concentration of 61 Bcf/mi^2. Within the 2,950 mi^2 prospective area, the shale formation is estimated to contain a risked gas in-place of 43 Tcf, of which 9 Tcf is regarded as technically recoverable (EIA, 2011).

The reservoir and geochemical properties are given below according to their maximum values obtained from the core&cuttings (Aydemir, 2010);

- Thickness: 100-400 m
- Type II- Kerogene
- TOC: 0.5 - 16%
- $S_1 + S_2$: 2000 - 50000
- T_{max}: 435 - 465 ^oC

Also, some other reservoir properties and the reserves estimated by Advanced Resources International Inc. (ARI) are given in the Table 5.

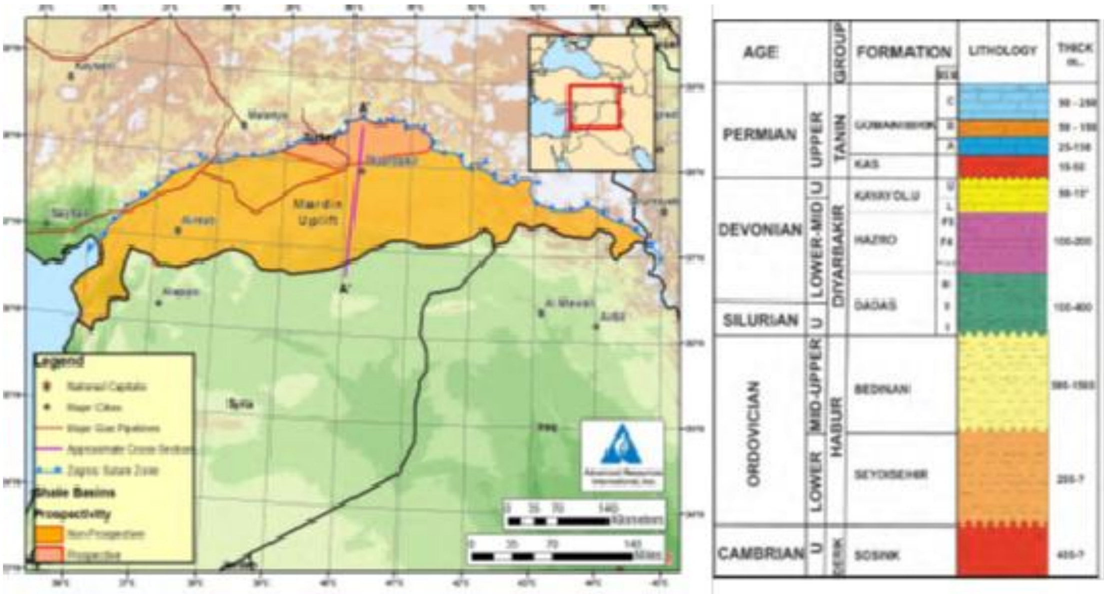

Figure 11 : The area and the reservoir characterization of Dadas Shale (EIA, 2011)

3.2. Exploration and production activities

There were drilled almost 15000 unconventional wells in 2010 all over the world. Only 50-60 of those were outside the North America. So, it can be seen that the unconventional operations are going on too slowly by comparison with that continent, mainly the U.S. Although the shale gas potential is becoming a popular issue in the import dependent Turkish energy sector, the exploration and production activities about shale gas are limited in Turkey, yet, in parallel with the global activities outside the U.S.

In the vast Dadas Shale around Diyarbakir, TransAtlantic Petroleum Co. and fellow Canadian-listed firm Valeura Energy are conducting drilling activities. Also, the firm called Anatolian Energy can be said active in the Dadas Shale (Natural Gas Europe website, 2013). However, the most important and promising shale gas exploration activity in the region is Royal Dutch Shell's. Shell has established a partnership with TPAO about exploration shale gas resources in Diyarbakir, Dadas Shale. The drilling of the first well, Saribugday-1 is continuing. After the completion of this well, an additional two or three wells are planned to be drilled until the end of 2013 by the joint venture of TPAO and Shell.

According to the results of the first well drilled, Southeastern Anatolian shales are expected to attract new significant investments from domestic and foreign companies. Thus, it was declared by General Manager of TPAO that Exxonmobil is already closely interested in partnership with TPAO about the shale resources in Turkey. (Bugün, 2012)

Also, TransAtlantic Petroleum Co. and Valeura Energy have some licences in the region and they have applied some hydraulic fracturing operations targeting for both shale oil and shale gas that they have got to the production stage, but it can be said that the production rates do not meet the expectations. In addition to them, Anatolian Energy has spudded an exploratory well in the formation (Natural Gas Europe website, 2012).

After the Dadas Shale of Southeastern Anatolia, the second important region is the Thrace Basin. It covers over 22.000 km^2 area in European Turkey. Besides the unconventional resources, there are also about 350 wells drilled for conventional gas resoures and three oil fields (EIA, 2011).

Although the Thrace Basin is under active conventional gas development by a number of domestic and international firms, its shale gas potential is only being targeted by Transatlantic Petroleum. As in the SE Anatolia Basin, Transatlantic has entered into an agreement with TPAO to recomplete and test wells in prospective shale formations (EIA, 2011). Transatlantic's current agreement calls for the company to recomplete some wells like Kayarca-1 and Kepirtepe-1, on a centrally located lease in the Thrace Basin and drill an additional three to four wells over the coming years (TPAO website, 2013).

In addition to these studied resources, also there some other formations that may have serious amount of shale deposits. To exemplify, Kiradağ, Kaş and Bedinan are the other parts of the Southeastern Anatolian Basin besides the Dadas Shales. Also, Komurlu Formation in Eastern Anatolian Basins Caglayan Formation in Blacksea Basins, Karapinar Yaylasi Formation in Saltlake Basin and Akkuyu, Carboniferius and Silurian Formations in Taurus Basins are the other potential Shale deposits in addition to Dadas and Thrace Basin Shales (Aydemir, et.al., 2013). Due to the lack of enough exploration activities, there is not exact information about these formations. However, there are exploration licences given to the companies mentioned above and some others.

CHAPTER 4

STATEMENT OF PROBLEM & SCOPE

This study is undertaken to estimate the amount of the shale gas resource and economic viability of one of the Turkish shale gas plays. The selected resources to be used in the case study is the Dadas shale of the Southeastern Anatolian basin. In addition to the highly uncertain and risky characteristics of the shale gas reservoirs, the lack of adequate geologic and engineering data in the Dadas shale due to the insufficient exploration activity increases the uncertainty level of the reservoir. The objectives of the study are;

- Estimating the original gas in place in the Dadas shale resources with Monte Carlo simulation method by using the data about the reservoir properties determined by different surveys held by Advanced Resources International (ARI), TPAO, and some other firms, institutions and researchers.
- Estimating the recoverable amount of the reservoir by assuming a reasonable recovery factor.
- Designing a reasonable well spacing and determining a plan specifying the development of the field to go into production.
- Analysis of the economic viability via doing a Net Present Value and Internal Rate of Return estimation by the planned expenditures and the expected incomes in parallel with the development and production plans of the field.

CHAPTER 5

LITERATURE REVIEW

It is certain that the interest on the global shale gas resource potential is growing with some reasons mentioned in the previous sections of this study. The volume of the prospective gas resources and the exploration efforts are intensified by the industry. Although the current experiences outside the United States are insufficient, there are a few number of important academical studies examining shale gas reserve estimations and their economic viabilities under the reservoir uncertanties. Some of these examined studies are summarized below.

Almadani (2012) estimated the economically recoverable gas for unconventional plays by quantifying the impact of changes in finding and development costs (F&DC), lease operating expenses (LOE) and gas prices. To develop the methodology, he had performed an economic analysis using data from the Barnett shale, as a representative study. By using the cumulative distribution function of the values of the Estimated UltimateRecovery (EUR) for wells, Almandi determined the P10, P50 and P90 values. Then, he had used these probability values to calculate the technically recoverable resource (TRR) for the play and determine the economically recoverable resource (ERR) as a function of F&DC, LOE and gas prices.

Dong, et al. (2012), developed the data sets, methodology and tools to determine values of original gas in place (OGIP), technically recoverable resources (TRR), recovery factor (RF) and make an economic analysis in uncertain and risky shale gas reservoirs. To achieve these objectives, they proposed a model working through a computer program, namely Unconventional Gas Resource Assessment System (UGRAS). In the program, they integrated Monte Carlo technique with an analytical reservoir simulator to make the necessary estimations. They applied the UGRAS to dry gas wells in the American Barnett shale and Eagle Ford shale to determine the probabilistic distribution of their resource potential and economic viability. On the basis of their assumptions, the Eagle Ford shale in the dry gas portion of the play has more technically recoverable resources than Barnett shale. However, the Eagle Ford shale is not as profitable as the Barnett shale because of the high drilling costs in the Eagle Ford dry-gas window.

Weijermars (2013), evaluates the economic feasibility of five emergent shale gas plays of the European continent. The study makes a first attempt to evaluate the economics of five potential shale gas plays in Europe, by name Austria, Germany, Poland, Sweden and Turkey. Well productivity type curves are established for each play based on an earlier review of estimated ultimate recovery for the plays. Decline curve analysis provides the well productivity model that fits the EUR data. Subsequently, the net present value (NPV) and internal rate of return (IRR) of each shale play are calculated by applying discounted cash flow analysis, using representative inputs for gas price, production cost, taxes, depreciation and discount rate. According to the results of the study, the ranking of these five shale gas basins from the most attractive one to the least is Poland, Austria, Germany, Turkey, Sweden, respectively.

CHAPTER 6

METHODOLOGY & THEORY

The objective of this study is to develop a methodology and tools to determine values of original gas in place (OGIP), recovery factor (RF) and technically recoverable resources (TRR) and evaluate the economic viability in uncertain Dadas shale formation. While doing these analysis, some existing approaches in literature, such as decline curves or volumetric analysis, may not be useful since there is not enough production history and due to high uncertanties in the shale reservoir. So, some relevant data from already gas producing shale formations in the USA, like the Barnett shale, is used and some assumptions are made within the scope of previous studies in the literature and again Barnett shale. Those will be stated explicitly in the relevant parts of the study.

6.1 Methodology

In this study, firstly, OGIP, RF and TRR are estimated with using petrophysical and reservoir properties of Dadas shale by performing a simulation. Reservoir simulation coupled with a stochastic model, Monte Carlo simulation method will provide a successful mean to predict the reservoir volume with the properties under some uncertainty. The uncertainty is assessed by generating a large number of simulations, sampling from distributions of uncertain engineering, geologic, reservoir data and other important parameters. Then, an optimum well spacing parameter is determined and the Estimated Ultimate Recovery (EUR) per well is reached. The next and the last step is comparing the costs for development of the field and the expected production and analysing the economic viability of the field by estimation of the Net Present Value of the project.

At this point, it is convenient to give some theoretical information about the concepts that is mainly used in the case study. Monte Carlo simulation method and triangular distribution type can be labeled as the fundamentals of the case study application.

6.2 Theoretical information

Monte Carlo simulation is a computerized mathematical technique that allows people to account for risk in quantitative analysis and decision making. The technique is used by professionals in such widely disparate fields as finance, project management, energy, manufacturing, engineering, research and development, insurance, oil & gas, transportation, etc.

Monte Carlo simulation performs risk analysis by building models of possible results by substituting a range of values—probability distribution—for any factor that has inherent uncertainty. It then calculates results over and over, each time using a different set of random values from the probability functions. Depending upon the number of uncertainties and the ranges specified for them, a Monte Carlo simulation could involve thousands or tens of thousands of recalculations before it is complete. Monte Carlo simulation produces distributions of possible outcome values.

By using probability distributions, variables can have different probabilities of different outcomes occurring. Probability distributions are a much more realistic way of describing uncertainty in variables of a risk analysis. The most common probability distributions can be named as normal, log-normal, uniform and triangular distributions (Palisade, 2013).

- Normal distribution, also called Gaussian distribution, the most common distribution function for independent, randomly generated variables. Its familiar bell-shaped curve is ubiquitous in statistical reports, from survey analysis and quality control to resource allocation.

The graph of the normal distribution is characterized by two parameters: the mean, or average, which is the maximum of the graph and about which the graph is always symmetric; and the standard deviation, which determines the amount of dispersion away from the mean (Britannica, 2013).

- Log normal distribution, is a continuous probability distribution of a random variable whose logarithm is normally distributed (Wikipedia, 2013).
- In uniform distribution, all values have an equal chance of occurring, and the user simply defines the minimum and maximum and has constant probability (Palisade, 2013).
- The triangular distribution is a continuous probability distribution with lower limit, upper limit and mode (Wikipedia, 2013). The user defines the minimum, most likely, and maximum values. Values around the most likely are more likely to occur (Palisade, 2013).

During a Monte Carlo simulation, values are sampled at random from the input probability distributions. Each set of samples is called an iteration, and the resulting outcome from that sample is recorded. Monte Carlo simulation does this hundreds or thousands of times, and the result is a probability distribution of possible outcomes (Palisade, 2013).

In this study, the uncertainties of the variable is quantified by a simulation of 10000 iterations. And also it should be stated that the distributions of the uncertain variables are assumed to be triangular because there is a lack of sufficient data to know exact data or any mean and standard deviation. The known minimum, maximum and most likely values gathered fom literature associating with author' s comments and analysis are for triangular distribution.

CHAPTER 7

APPLICATION: CASE STUDY

THE RESERVE ESTIMATION AND THE ECONOMIC VIABILITY OF DADAS SHALE

The application of the model is examined step by step through the objectives and scope of the study stated above.

7.1. Estimation of OGIP, RF, TRR

At the first step, The OGIP in the Dadas shale formation is estimated with Monte Carlo simulation method by using the petrophysical and reservoir properties outlined below.

Table 5: Reservoir and petrophysical parameters of Dadas shale (EIA,2011).

Parameter	Average value
Area (acre)	1.888.000
Net pay (ft)	136
Porosity (%)	6,8
Water saturation (%)	8,15
Depth (ft)	8200
Pressure	Normal

Table 5 lists the relevant reservoir and petrophysical parameters that is used in the simulation. Also, the initial and final distributions for uncertain Dadas shale parameters can be seen on Table 6. It should be stated that the mnimum, most likely and minimum values are determined with parallel to the literature findings and the author's comments where necessary

Table 6: Distributions for uncertain parameters.

Parameter	Minimum	Maximum	Most likely	Distribution type
Area (acre)	944.000	1.416.000	1.264.960	Triangular
Net pay (ft)	50	200	135	Triangular
Gas saturation (%)	0,8	0,95	0,9185	Triangular
Porosity (%)	0,06	0,08	0,068	Triangular
B_{gi} (RCF/SCF)	0,00375	0,00562	0,00464	Triangular

It should be stated that the distribution of the parameters are triangular and there is not any possible correlation among them.

As it is known, Original Gas In Place (OGIP) is calculated as follows;

$$OGIP\ (MMCF) = 0.04356 * A * H * \Phi * S_g\ /\ B_{gi} \ldots\ldots\ldots \quad \text{(Equation 1)}$$

where;

A = Area (Acres)

H = Net Pay (ft)

Φ = Porosity (fraction)

S_g = Gas Saturation (fraction)

B_{gi} = Initial Gas Volume Factor.

7.1.1. Inputs of the equation

Input parameters are compiled from the report of EIA, by name *"World Shale Gas Resources: An Initial Assessment of 14 Regions Outside The United States"* (EIA, 2011), Schumberger's Petrophysical Evaluation (Mitchell, 2013), TPAO' s evaluations through Mr. Aydemir's research papers (Aydemir, 2013) and Mr. Aydemir' s article (Aydemir, 2011). Also, for some parameters, that any sufficient data cannot provided, it is referred to Barnett shale formation, accepted as a similar reservoir (Dong, 2013). In addition to those, the author's comments and analysis is applied on some existing data.

7.1.1.1. Area

The total area of the formation lying on the Southeastern Anatolian Basin is accepted 2.950 sq mi, or **1.888.000 acres** as it is stated in the report of EIA, by name *"World Shale Gas Resources: An Initial Assessment of 14 Regions Outside The United States"* (EIA, 2011).

However, it is obvious that the area comprehending a shale formation with a net thickness within the range of the assumed values stated below (50 ft – 200 ft) cannot be equal to the size of the whole area.

According to the personal interviews with Mr. İsmail Bahtiyar, an expert of the shale gas exploration activities of TPAO in the region, the related area that can be mentioned in the model of this study as approximately the two third of the whole area. However, the minimum, maximum and the most likely values for a triangular distribution are set to be 50% as 944.000 acres, 75% as 1.264.960 acres and 67% as 1.416.000 acres, respectively for quantification of the remaining uncertainty.

7.1.1.2. Net pay (net thickness)

The net pay, or the net thickness parameter has important uncertainty due to the lack of sufficient data about mean, standard deviation and any other parameters about the distribution of the net pay of the Dadas shale. Because of this reason, the distribution is assumed to be triangular and the minimum, maximum and the most likely values are determined by synthesising the author' s comments and two different Dadas thickness value existing in the literature. First one is the net pay in the report of EIA, 150 ft (EIA, 2011). The other one is data gathered rom the Bahar-1 well drilled by Transatlantic Petroleum, 57 ft (Mitchell, 2013).

The minimum value is 50 ft, the maximum value is 200 ft and the most likely net pay value is accepted to be **135 ft** by etimating the average literature values and author' s comments**.**

7.1.1.3. Gas saturation

The gas saturation value is calculated by the simple formula of (S_g = 1- $S_{w)}$. The most tangible data about the water saturation in the Dadas shale formation is obtained from the Bahar-1 well, 8,15% (Mitchell, 2013). So, the gas saturation is to be 91,85%. However, it is obvious that the saturation value may not be same every part of the formation. To removing the uncertainty of this data as far as possible, the distribution of this parameter is assumed to be triangular and a minimum and maximum values of 80% and 95% are determined by the author's comment and the value of 91,85% is set to be the most likely value.

7.1.1.4. Porosity

The most tangible data about the porosity in the Dadas shale formation is obtained from the Bahar-1 well, 6,8% (Mitchell, 2013). However, it is obvious that the porosity value may not be same at every part of the formation. To remove the uncertainty of this data as far as possible, the distribution of this parameter is assumed to be triangular and a minimum and maximum values of 6% and 8% are determined by the author's comment and the value of 6,8% is set to be the most likely porosity value.

7.1.1.5. Initial Gas Volume factor

Like the other parameters, due to the lack of exact values of the pressure gradients, there is an uncertainty in the volume factor also and it is not possible to make exact calculations.

Then, the hydrostatic pressure is assumed to be normal and the volume factor is calculated with the simple formula of (B_{gi} = Depth / 36,9).

The depth interval is stated between 6560 ft and 9840 ft and the average depth is stated as 8200 ft in the report of EIA, by name "World Shale Gas Resources: An Initial Assessment of 14 Regions Outside The United States" (EIA, 2011). According to this data put in this simple formula, the minimum, maximum and most likely volume factor values are calculated as 0,00375, 0,00562 and 0,00464 if it is assumed to have triangular distribution to quantify the uncertainty as far as possible.

7.1.2. Results

Since, most of the parameters contain uncertainties, as it is stated before, it is convenient to apply Monte Carlo simulation to the data set as given above.

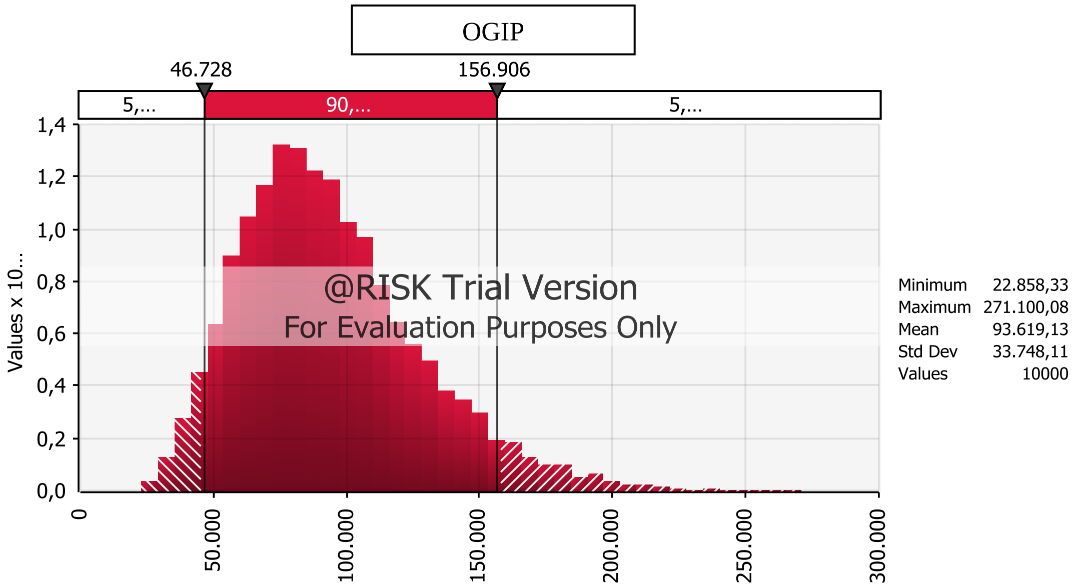

Figure 12: Risk distribution of the OGIP simulation results.

According to the apllied Monte Carlo simulation with 10.000 iteration, the probability density distribution and cumulative probability distribution graphs illustrated in Figure 12 and Figure 13, the results yielded an OGIP distribution with a **P10** value of **53,96 Tcf**, a **P50** of **88,6 Tcf** and a **P90** value of **140 Tcf**.

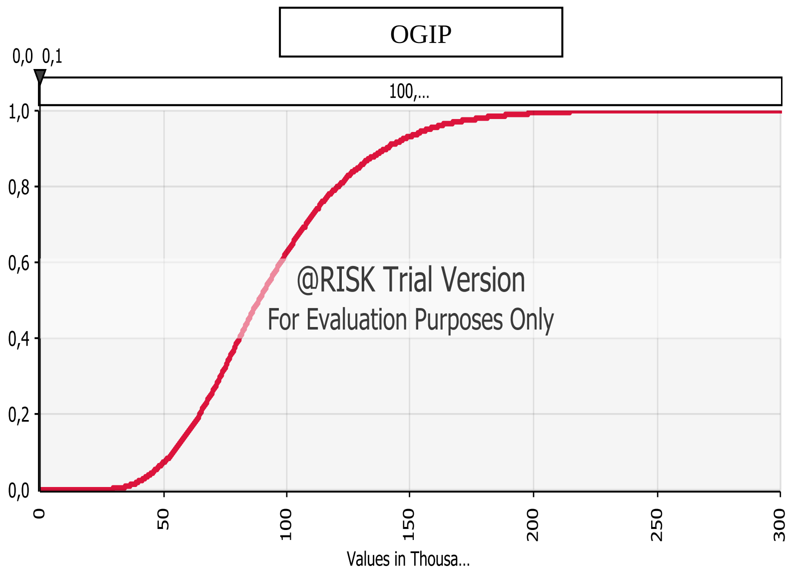

Figure 13: Cumulative probability distribution of the OGIP simulation results.

It should be stated that in our estimations of TRR, optimum well spacing, NPV and IRR values, the **P50** value of **88,6 Tcf** is used.

Technically recoverable resource (TRR) is the volume of petroleum which is recoverable using current exploration and production technology without regard to cost, which is a proportion of the estimated in-place resource. Also, TRR of shale resources are known to be smaller than conventional resources. Since, sufficient geologic and reservoir data do not exist for Dadas formation, a recovery factor (RF) of 15% is assumed through the value set for Turkish shales stated in *"Strategic Perspectives of Unconventional Gas: A Game Changer With Implications For The EU' s Energy Security"* (Kuhn and Umbach, 2011) and similar with the parallel formation of the Barnett shale (Dong, et al., 2013) .

So, by the equation of TRR calculation;

$$TRR = OGIP \times RF \quad \text{.......(Equation 2)}$$

TRR= (93,6 Tcf) x (0,15) = 13,3 Tcf

The technically recoverable gas resources in Dadas formation is **13,3 Tcf.**

7.2. Well spacing

After the estimation of TRR, the next step is determination of the optimum well spacing for the field.

This "optimum" number should satisfy both the technical and economic criteria. A single well can theoretically drain the whole reservoir, but it would take ages and become uneconomical. Thousands of wells can drain it faster, but it would be costly and again uneconomical. Between these two extremes, there ought to be an ideal number of wells that would yield maximum profitability. At this point, the Corrie equation is assumed to be applied to determine the optimum well number of shale gas reservoirs. After making some simplifying assumptions, Corrie analytically determined an optimum number by finding the maximum economic return from the equation below:

$$W_o = \frac{N_p}{365QC}\left\{\sqrt{365QVC\ln(1+i)} - \ln(1+i)C\right\} \quad \text{.......(Equation 3)}$$

Where:

W_o = optimum number of wells, number
N_p = cumulative producible gas, Tcf
Q = initial gas production rate per well, MMSCF/day
V = gas price netted back to the well, $/MMSCF
C = capital expenditures per well, $
i = discount rate, fraction per annum

7.2.1. Inputs of the equation

Here, the certainty of the the reservoir and financial variables are important.

7.2.1.1. Cumulative producible gas

The variable of cumulative producible gas (N_p) is technically recoverable resource determined above, **13,3 Tcf.**

7.2.1.2. Initial gas production rate per well

Q, initial gas production rate per well, cannot be determined before it is passed to the production phase in the field. So, it is mandatory to make an assumption and as previously done. In the result of the literature survey, the initial gas production rate in American shale gas wells vary in a reasonable range. For example, in Fayetteville shale gas wells Q varies between 1,0 to 2,6 MMSCF/d. This rate varies in Woodford shale wells between 2,1 and 3,6. And in vertical Barnett shale wells, initial production rate is approximately 2,0 MMSCF/d (Baihly et.al., 2010). The average initial production rate of the Barnett shale in the literature is averagely assumed as the Q of Dadas shale as **2,0 MMSCF/d.**

7.2.1.3. Gas price

As it is known, Turkey imports the majority of her natural gas requirement via pipeline from 3 main countries, Russia, Azerbaijan and Iran with different prices and there is not any organized market structure that prices are occured in a liberally. So, to estimate V, gas price in Turkish market, the average import price gas can be found with a small calculation as follows;

Table 7: Turkish natural gas import amount and prices. (EPDK, Enerjigunlugu, 2013)

Country	Import amount of most recently announced,2011 (bcm)	Average import price ($/1000m^3)
Russia	25,4	430
Iran	8,2	530
Azerbaijan	3,8	355

If the weighted average of the amount and price is calculated, the average import price of Turkish market can be found as $444/1000m^3, in other words $12.570/MMSCF. However, due to some political reasons and market powers, BOTAS is selling the imported gas under the import price, at **$10.760/MMSCF** in the wholesale market recently and the market price occurs generally around this level (BOTAS website, 2013).

7.2.1.4. Capital expenditures per well

The variable, C represents the capital expenditure per well. The average cost for unconventional drilling wells may vary from country to country and from field to field and number of fracturing stages. Performing several stages of fracking to ready a shale gas well for production can cost a producer upwards of 2-3 million dollars per well in the United States (Hefley, et. al., 2011).Also, the result got from the literature review reveals that average drilling and completion costs including acquisiton and landing costs, drilling pad preperation, rig site costs, daily drilling costs, labor costs, multi-stage fracturing costs including fracturing fluid, transportation, truck fleet costs, etc per a shale gas well in Europe reach two to three times of an American well due to the market structure, service requirements, industry infrastructure, etc.

The average drilling and comletion cost per well stated in *"Strategic Perspectives of Unconventional Gas: A Game Changer With Implications For The EU' s Energy Security"*, estimated through Wood Mckenzie, DeutscheBank and CERA' s reports and the author' s own analysis, is **$8,07 million dollars** for Turkey (Kuhn and Umbach, 2011). This amount approximately confirms the theory that it is about 2,5 times of an American well.

7.2.1.5. Discount rate

The interest rate or discount rate is assumed as **10% annually** that reflects the average rate that usually accepted in the oil and gas sector.

7.2.2. Result

By using these parameters, the optimum well number (W_o) is calculated through Equation 3 as **5189 wells**. This result also corresponds to a well spacing of **233 acres/well** when all of these wells are drilled uniformly through the part of the formation of comprising of net thickness between 50 ft an 200 ft.

7.3. Economic analysis

After determining the OGIP, RF, TRR and well spacing of the field, the the next step is to making the economic analysis of investment with such a development plan. Hereby, the discounted cash flow analysis model is used to calculate the Net Present Value (NPV) and the internal rate of return (IRR) of the project before tax using inputs for, production costs (CAPEX and OPEX), depreciation rate, discount rate, gas price, decline rate of the production and royalty rate. During this estimation, Monte Carlo simulation method is used to quantify the uncertainties about the inputs.

Within the scope of the development plan, the Dadas field is assessed by using a sensitivity analysis of two uniform field development plans of 25 years and 40 years life cycles.

In the first plan, a **10 years drilling plan** with a rate of **519** drilled wells/year is projected. So, the optimum well number is reached in a period of **10 years**. The gas production from the realized wells is monitored over a plan of **25 year life cycle**.

In the second plan, a **25 years drilling plan** with a rate of **207** drilled wells/year is projected. So, the optimum well number is reached in a period of **25 years**. The gas production from the realized wells is monitored over a plan of **40 year life cycle**.

7.3.1 Inputs of the model

The inputs of the model are examined below.

7.3.1.1. Gas Price

The produced gas is sold approximately at the wholesale gas price of BOTAS in American dollars determined with parallel with the national import prices (Botas website, 2013). This price is assumed to be purified from any market power like political pressure, subsidies etc.

This price is almost **$10.760 per MMSCF**.

7.3.1.2. Capital expenditures

The capital expenditure for a shale gas development is to a large degree determined by its subsurface properties and technology solutions selected for extraction As stated above, the average drilling and comletion cost per well including acquisiton and landing costs, drilling pad preperation, rig site cost, daily drilling costs, labor costs, multi-stage fracturing costs including fracturing fluid, transportation, truck fleet costs, etc is assumed to be **$8,07 million dollars.**

7.3.1.3. Operational expenditures

The operating expenditure (OPEX) for large conventional oil and gas projects is often indexed at 5% of total CAPEX. However, for shale gas wells it may be more appropriate to index OPEX to well flow performance. For example, for the Barnett OPEX has been fixed at $1/Mcf as a benchmark (Madani and Holditch, 2011). An additional rate for general and accounting cost should be added at a rate of

0,5 \$/Mcf (Weijermars, 2013). According to Kuhn and Umbach, the average OPEX for a shale gas well in Turkey is \$1200/MMSCF and the other OPEX is \$1000/MMSCF (Kuhn and Umbach, 2011). The total OPEX used as an input in this model is **\$2.200/MMSCF.**

7.3.1.4. Depreciation

Depreciation rates for investment in tangibles must comply with the established accounting practices. The rate to be used is sometimes prescribed by a regulatory agency. For example, the SEC in the USA mandates 10% depreciation rate should be used in economic assessments related to reserves reporting (Weijermars, 2013). With parallel to this American application, the depreciation rate in assumed to be 10%.

7.3.1.5. Royalty Tax

A percentage share of production, or the value derived from production, paid from a producing well to the government is called royalty tax**. The royalty tax** laid down by the laws in Turkey is **12,5%**. So, the 12,5% of the gas revenue is paid to the government as the royalty tax.

7.3.1.6. Discount rate

The annual rate of discount accounting for time value of money, in other words discount rate is determined as **10% annually** that reflects the average rate that usually accepted in the oil and gas sector.

7.3.1.7. Estimated Ultimate Recovery and Decline Rate

It would be an important counseling for the economic analysis of the development of the non-American that if the well productivity of US shale gas plays are examined well. For instance, if a review of US well productivities, using 46.506 shale gas wells, gives a 40-year mean EUR of 1,14 Bcf. Also, as a similar formation, in the Barnett shale, the mean EUR for representative horizontal wells is 1,4 bcf/well, but there is considerable spread in well performance for subareas. In the 'best areas' for the Barnett a representative mean EUR is 2,1 bcf/well, and the 'worst areas' have a mean EUR of 0,59 bcf/well (Weijermars, 2013). For this study, it is assumed that the well EUR can be modeled by an exponential decline function:

$q_n = q_i\ (1+\alpha)^n$ ……………………………………………………………………………….…(Equation 4)

where;

q_n is the flow rate in year n,
q_i the starting flow rate in first year
α is the annual decline rate (a negative fraction),
n is the number of years.

Since there is not any production from the Dadas field, there is not any information about the decline rate. So, this parameter should be assumed for a reasonable value. The decline rate in this study is assumed to be **-15%.**

The EUR/well is calculated with technically recoverable resources of 13,3 Tcf and optimum well number of 5189, the EUR/well is to be approximately **2,6** Bcf.

Then if the EUR/well and annual decline rate values are taken into consideration, In the first plan of a 25 years life cycle, the gas production of the first year is to be **0,39** Bcf per well. And the cumulative production of the prospective years are to decline year by year after the end of the 10 years' drilling program. The annual gas production of 25 years' lifecycle of the project is shown in the figure below.

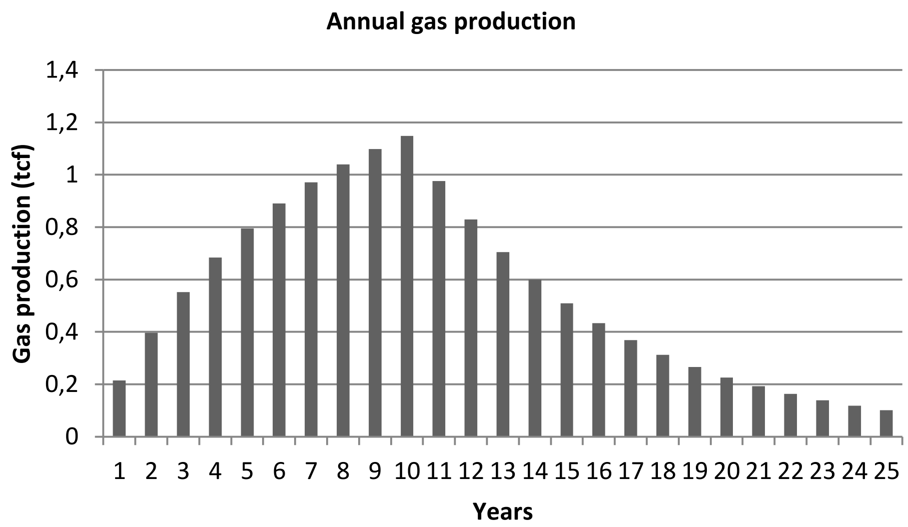

Figure 14: Annual gas production of the first plan.

In the second plan of a 40 years life cycle, the gas production of the first year is to be **0,39** Bcf per well. And the cumulative production of the prospective years are to decline year by year after the end of the 25 years' drilling program. The annual gas production of 40 years' lifecycle of the project is shown in the figure below.

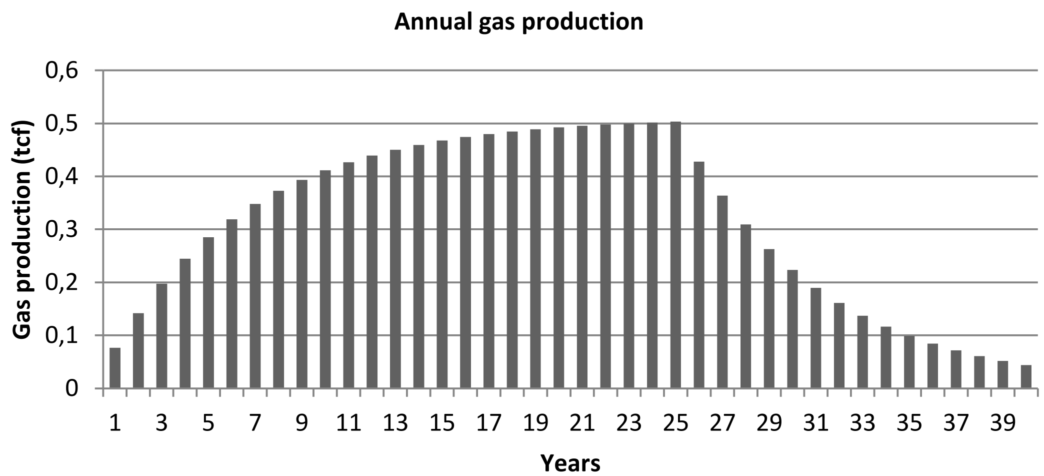

Figure 15: Annual gas production of the second plan.

7.3.2. Results of the model

The expected results, or outputs of the model are Net Present Value (NPV) and the Internal Rate of Return (IRR), showing the economic viability of the project.

7.3.2.1. Net Present Value (NPV)

When all these input parameters are entered to the model driven by Monte Carlo simulation method, the mean of Net Present Value distribution of the presented first development project is estimated as **$8.468.513.684**.

The probability distribution of the simulation results of the first plan is shown below.

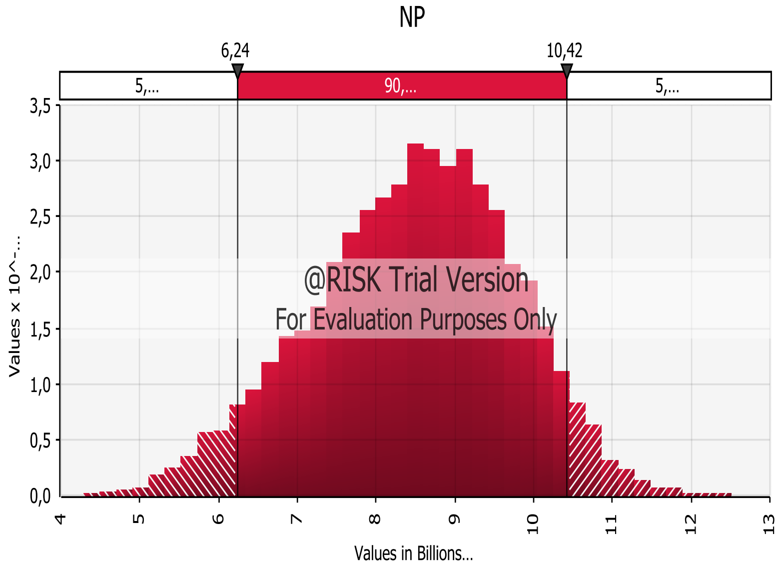

Figure 16: The simulation results of the NPV of the first development project.

The mean of Net Present Value distribution of the presented second plan with the 40 years' life cycle development project is estimated as **$4.605.030.738**.

The probability distribution of the simulation results of the second plan is illustrated below.

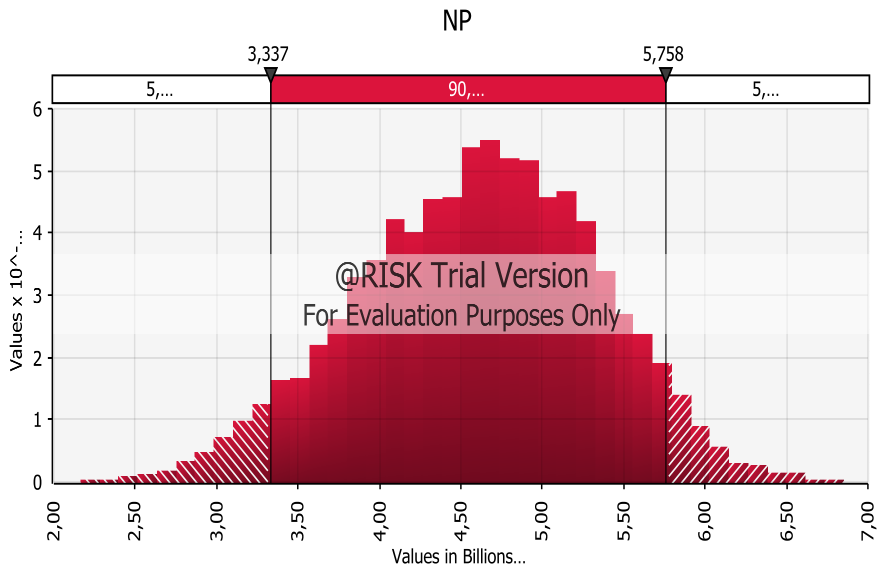

Figure 17: The simulation results of the NPV of the second development project.

7.3.2.2. Internal Rate of Return (IRR)

The internal rate of return of the first development project is approximately **21,5%.** And the payback time is **between 4 and 5 years.**

Also, the cash flow graph comprising the 25 years life cycle is illustrated below.

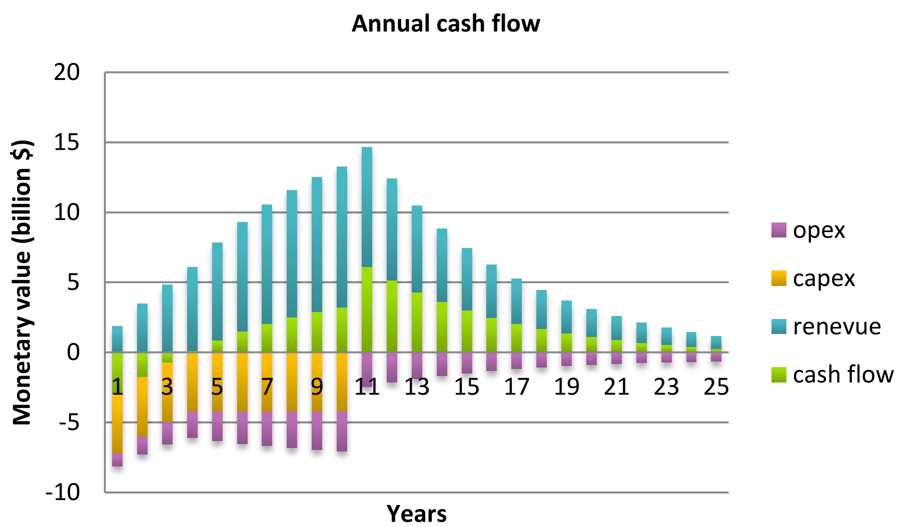

Figure 18: Annual cash flow chart of 25 years' life cycle.

The internal rate of return of the second development project is again approximately **19,8%.** And, the payback time is between **4 and 5 years.**

Also, the cash flow graph comprising the 40 years' life cycle is illustrated below.

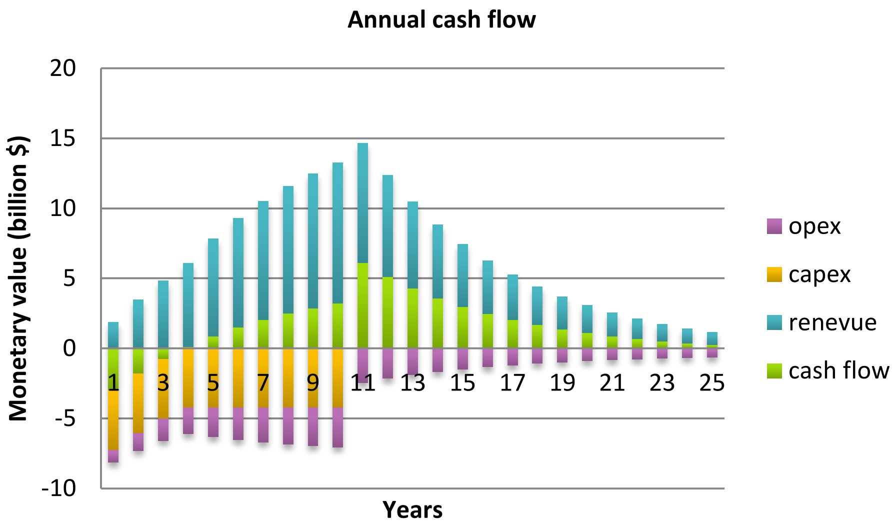

Figure 19: Annual cash flow chart of 40 years' life cycle.

If these two devlopment plans are compared, it can be seen that the IRR values are very closed to each other. However, the NPV of first development plan is obviously greater than the second. On the other hand, it is a fact that the 10 years' drilling program with a rate of 519 wells/year is more difficult to achieve than the 25 years' drilling plan with a rate of 207 wells/year. So, if the industrial infrastructure and the other factors like labor, intensive engineering schedule, etc. are no longer a problem, than the first plan appears to be more attractive to work with it higher NPV and IRR values..

These monetary values are worth if all of the field of such a considerable size of area is developed and all of the technically recoverable resources of 13,3Tcf of the shale gas is extracted by a huge drilling and production program similar to the gigantic American shale plays.

CHAPTER 8

DISCUSSIONS

The results of original gas in place and technically recoverable resources of Dadas shale gas reached from the estimations are evaluated to be more than the estimations of Energy Information Administration that revealed in the report of *"World Shale Gas Resources: An Initial Assessment of 14 Regions Outside The United States"* in 2011 (EIA, 2011). However, it may be regarded as reasonable when the objective forecasts about the Turkish shale gas potential made by some experts or media.

It should be stated that the tools used in this study could be helpful in assessing the amounts of reserves in shale gas plays. However, it is necessary to acknowledge the assumptions and some uncertainties in the results of estimations.

Although it is an assumption, 25 and 40 years' life cycles and an IRR above the level of 20%, a payback time below five years are generally accepted rationale by the oil and gas industry. But, different results may be found with different parameters of these criteria.

Also, the resource assessments are made for entire formation, reservoir and well properties were modeled as well-by-well basis instead of a whole. Through probability distributions and simulations, the uncertainties of these reservoir and petrophysical properties like net pay, porosity, gas saturation etc. were tried to be quantified. If the fact that these parameters may vary through portions of such a large area of the play.

The facts that it is not went into the production stage from the field yet and the reservoir and petrophysical properties are not declared to the public officially dispatch the study to make these assumptions. It should be stated that more accurate estimations would be done after the reveal of the first results of the wells drilled in Dadas and moved to the stage of production.

CHAPTER 9

CONCLUSION

Turkey is one of the lucky countries that being accounted of reserving significant amount of shale gas under its soils. It is estimated that there are two main shale plays in the Thrace Basin and the Dadas Formation of Southeastern Anatolian Basin, which is the more prospective one. But the important questions are whether these resources are large enough to contribute for removing the import dependency of the country and is it economically viable for setting out to develop the fields. While the first wells are being drilled, this study purpose to answer these questions.

In the first part of the study, a general information about the unconventional resources, shale gas, global reserves and E&P activities by region is given. In the second chapter, the shale gas potential, reservoir and petrophysical characteristics of the formations and E&P activities regarding shale gas extraction are examined. After stating the problem and the scope in the third chapter and the literature review in the fourth chapter, in the last chapter, the shale gas potential of the most promising formation, Dadas is tried to be determined in terms of original gas in place and technically recoverable resources beside the studies done in the literature and the economic analysis of the development plan of the field is done through simulations in order to quantify the uncertainties of data since it is not possible to get sufficient data about the field before they are declared after the first results.

Concepts like stochastic uncertainty modeling is regarded as crucial for forward field development planning based on realistic well productivity assessment and sound economic appraisal. Accordingly, by the simulation done within the study, the original gas in place in the Dadas shale formation is estimated as 88,6 Tcf with P50 wells. The technically recoverable resources are determined as 13,3 Tcf with a recovery factor of 15%.

The optimum well number should be drilled in the field is calculated as 5189 and the optimum well spacing is set to 233 acres/well. This value can be regarded as reasonable when compared to some other American shale formations

At the next and the final step, with the data and the parameters determined and stated above, the Net PresentValue (NPV) and the Internal Rate of Return (IRR) of two development plans are determined. In the first plan, we need to drill 519 wells/year in the life cycle of the project as 25 years with a drilling program of first 10 years. The NPV and the IRR of this plan are estimated as $8.468.513.684 and 21,5%, respectively. In the second plan, we need to drill 207 wells/year in the life cycle of the project as 40 years with a drilling program of first 25 years. The NPV and the IRR of this plan are estimated as $4.605.030.738 and 19,8%, respectively.

Since the indisputable importance of the place of the natural gas in the primary energy resources of Turkey and the import dependency of the market is taken into consideration, the amount of the investment can be regarded as reasonable with the huge amount of extracted gas, 13,3 Tcf. This amount equals to approximately 376 bcm and it meets more than the 8 years' demand of Turkish natural gas market with a simple calculation by means of a 45 bcm realized consumption in 2012.

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