SHALE GAS:
A GAME CHANGER WITH IMPLICATIONS FOR EUROPE

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The greatest energy innovation of the decade, according to Daniel Yergin, is “unconventional” natural gas [1]. Although, unconventional gas is nothing new to the oil and gas industry, and the supposed shale gas revolution is rather an unfolding evolution -a combination of several old and new technologies. Unconventional gas – from shale, coal-bed methane and tight formations – has been produced in the US since 1800s.[2] The first commercial shale gas well was drilled in 1821 into the Devonian Dunkirk shale near the village of Fredonia, New York to provide fuel to illuminate local homes. [3] For the supply-and-demand-driven oil and gas industry, natural gas did not become an important commodity until the end of World War II. Subsequently, in the 1980s producers began looking beyond traditional sources of natural gas production to keep up with the growing market and to compensate for depleting reservoirs. By the early 1990s the industry began evaluating coal-bed methane and later shifted its attention to shale gas. [4] It was not until around 2005, when the potential of unconventional gas became fully clear. In a time of soaring gas prices, rapidly depleting conventional wells, and failed attempts to bring forth additional supplies, the U.S. was destined to become an importer of liquefied natural gas (LNG). The surge in unconventional gas production in the U.S., however, led to a reassessment of the long-term gas balance. In recent years the U.S. supply assumptions have been turned upside down by the successful development of domestic shale gas.

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WHAT IS UNCONVENTIONAL GAS?

Conventional gas is generally extracted by drilling into porous reservoirs from where the gas can easily migrate to the well bore and up to the surface in relative free flow. Unconventional gas refers to gas extracted from formations where the permeability of the reservoir rock is so low that the gas cannot easily flow (e.g. tight sands), or where the gas is tightly absorbed and or attached to the rocks (e.g. coal-bed methane). There are many types of unconventional gas resources, which include tight gas that is of relative poor quality with low porosity and low permeability. The two principal types are: a) coal-bed methane (CBM), commonly known as firedamp in coal mines, which is a natural gas/methane that can be produced industrially with oil technologies. b) shale gas, derived from a source rock that has matured and produced gas. The main focus of this paper will be on shale gas.

Usually unconventional gas is found as dry and clean natural gas in the shale formations, either as free gas in fine-grained rock pores with low permeability, as free natural gas in natural fractures, or by clay particles absorbed gas on organic matter and mineral surfaces.[5] Shale formations can act as both a source and a reservoir. In the United States, these reservoirs tend to be found within a depth range of 80 to 2500 meters and have a prospected thickness of around 100 - 200 meters. [4] The major North American shale reserves are in the Marcellus Shale in Appalachia, Haynesville, on the border of Louisiana and Texas, and the Barnett Shale in Texas.

In the United States (U.S.), the definitions of unconventional and conventional gas were arbitrarily specified by taxation issues implemented in the 1970s. According to the taxation code, conventional gas is produced gas from a tight gas well whose permeability is equal or less than 0.1 microdarcy. Depending upon the permeability, the well can receive state or federal tax credits for the production of gas. However, flow rates of gas are determined by a number of both economic and physical properties independent of permeability, thus choosing a single value of permeability to define unconventional or tight gas is of limited significance. For example, in deep, high-pressure, thick recovers, commercial completions can be achieved when the formation permeability to gas is in the microdarcy range (0.001 md). In shallow, low-pressure, thin reservoirs, permeability of several millidarcies might be required to produce the gas at economic flow rates, even after a successful fracture treatment.

The National petroleum Council [6] defines unconventional gas as "*natural gas that cannot be produced at economic flow rates nor in economic volumes of natural gas unless the well is stimulated by a large hydraulic fracture treatment, a horizontal wellbore, or by using multilateral wellbores or some other technique to expose more of the reservoir to the wellbore.*"

WHAT IS TYPICAL UNCONVENTIONAL GAS?

Actually, there is no “typical” unconventional gas. Generally, gas is extracted from reservoirs, and it is the more accessible reservoir over the last centuries that have been defined as “conventional” exploitation of the hydrocarbons. Reservoirs can be deep or shallow, high or low pressure; high temperature or low temperature, blanket or lenticular; homogeneous or naturally fractured, and contain single layer or multiple layers. A function of each unique reservoir characteristics and the economic situation defines the optimum drilling, completion, and stimulation method.[6] Therefore, the challenge is to release the gas in each unique reservoir from rock that can be as impermeable as concrete. Hence, when permeability requires stimulation to achieve sustained gas flow the process has been labeled “unconventional” gas exploration.

DEVELOPMENT OF UNCONVENTIONAL / SHALE GAS IN THE U.S.

The major oil and gas companies neglected the potential of the organically rich gas shale reservoirs, which were considered as a sealing layer rock that drillers - for conventional resources - passed through, for a long time, thus avoiding the stimulation techniques that are required to exploit shale gas. [7]

Shale plays were regarded as a small-scale niche plays because of the low productivity and drillers traditionally sought the larger and less intensive exploitation opportunities, thus aiming at faster returns on their investments. New exploration and development technology changed the picture and made unconventional shale gas recoverable in areas where previously thought to be infeasible and economically unrecoverable.

The so-called “shale gas revolution” received public attention with the reassessment of the United States’ non-proven reserves in 2007/2008, when the U.S. Potential Gas Committee raised its estimate of unproven U.S. gas resources by an astonishing 45%, from 32.7 trillion cubic meters (TCM) up to 47.4 TCM. Similarly, Wood Mackenzie estimates that unconventional production in the U.S. lower 48 states has risen from 33% of total output in 2000 to 59% in 2009, and predicts that its share could reach 73% by 2020. Equally newsworthy was the effect on U.S. gas production, and its dramatic supply impact leading to continued weak gas prices on the spot market. Unconventional gas production in North America now accounts for about a half of U.S. gas production. U.S. production accounted for 599bcm in 2009, up 52bcm or 9.4% over two years driven by shale gas production, making the United States the de facto No.1 producer of gas worldwide, overtaking Russia.

WHAT MAKES SHALE GAS SPECIAL?

The prize in accessing these very large gas volumes is that the potential unconventional resources are several times the order of magnitude than that of conventional sources. A study by IHS Cambridge Energy Research Associates (CERA) calculates that the recoverable shale gas outside of North America could be larger than the entire world's gas discovered to date. [8] Estimates of recoverable resources are increased at a greater pace as technological advances permit access to gas from "unconventional" resources. The most prolific shale reservoirs are relatively flat, thick, and predictable; the formations are so large that once drilled for production, the wells are expected to produce gas at a steady rate for decades. Generally, it is assumed that shale gas wells flow rates are considerably lower than their conventional peers, but once the production stabilizes, the well will produce consistently for 30 years or more. [4]

The growth in unconventional gas resources exploration in the U.S. in last decade was initially driven by high gas prices over the period 2005-2008. It represented a "mainstreaming" of sorts, becoming a business focus of larger, more established and independent mid-cap oil and gas producers such as Devon Energy, Chesapeake Energy, and XTO Energy. It represented a culmination of years of effort by a small group of risk-taking independents in the U.S. best exemplified by George P. Mitchell and his brother, Johnny, of Mitchell Energy & Development.

The brothers were pioneers in trying to solve the perennial problem of how to liberate and extract the plentiful supplies of the locked away impermeable shale gas. [1] [8] Mitchell and his team of geologists and engineers worked on the shale challenge for over 12 years, from around 1981 to 1993. They experimented with different technologies on wells, many barely commercial to cover the costs of completion, to make shale gas work by freeing up the gas and stimulate the gas flow into the wellbore. Melting together two key technologies - horizontal drilling and "slick water" hydraulic fracturing - finally cracked the shale rock and thus cracked the code for major North American shale gas resources. Yielding significant increase in well production and leading to a series of incremental improvements which have enabled them and other operators in the United States to unlock the vast potential of these challenging resources, and to build shale gas production eventually to levels where it has become a significant factor in the nation's production of gas. [6, 9] The recognition that one could "create a permeable reservoir" and high rates of gas production in deep shale formations by using enhancements which were perfected through research and development by smaller "independent", and by oilfield service companies, who together took a decades-old technique – horizontal drilling and hydraulic fracturing, to get more oil and gas out of the ground and perfected it to work in dense shale formations and therefore changed the game for unconventional gas. [10]

Horizontal well drilling has progressed from an art to a science. Instead of drilling straight down into the resources, horizontal drilling enables to go sideways after a certain depth, opening up a much larger area of the resource-bearing formation and therefore a greater length of the shale gas deposit to be in contact with the well bore. The other key technology is hydraulic fracturing, which creates multiple productivity and same production at one quarter of the costs and has a much smaller footprint than vertical drilling. [11] Hydraulic fracturing was first used as a method to artificially stimulate oil wells, and was introduced in the late 1940s in Texas oil fields. The technique has been improved, refined over the years, and more recently, adapted to maximize exploitation of shale gas formations. Hydraulic fracturing involves isolating sections of the well in producing zone, then pumping a mixture of steam water, fluids and proppant (grains of sand or other materials used to hold the crack open) down the wellbore through perforations in the casing and out into the shale. The hydraulic pressure created by pumping fluid into the well, under pressure up to 8,000 psi, is enough to produces fissures in the reservoir and crack shale as much as 1000m in each direction from the wellbore, liberating the trapped gas and boosting the migration of the gas flow through the created multiple fractures in the rock into the wellbore. Even without proppant, the cracks stay open for a while, but they will eventually heal and the gas production will decline accordingly. The more fractures in the shale around the wellbore the faster the gas will be produced. [4] Thus, fractures are the key to good production, but keeping them open after the pressure is released while the well is producing is a tricky process. [12]

Research and technological innovation, enhancements for prospect evaluation and core testing, shale lithotyping to determine key characteristics of productive shale, optimization and tailoring water-fracturing fluid chemistry to the shale and remedial treatment processes for obtaining long-term production, have increased the potential per-well gas recovery factor up to 20%. State-of-the-art technologies have opened new areas by reducing overall exploration, production and operation costs. [13] Knowledge of the methodology is the most important constant in the speed and efficiency of bringing on shale gas production. Understanding the complex unconventional gas reservoirs is a critical step in designing optimal fracture geometry, fluid interactions, evaluation processes, micro-seismic surveys, tracers, and production logs. Collaboration and sharing information across disciplines, so that insights are leveraged as effectively as possible, is a key factor and central to improve production. Ultimately, this knowledge sharing helps create a single strategy and facilitate a holistic view of the reservoir throughout its development, which brings with it various insights needed to create shared efficiencies and synergies. [14]

FALLING COST NOT A GIVEN?

George P. Mitchell should be credited with cracking the code that opened the shale plays across North America and perhaps elsewhere in the world. He is also recognized as the one who helped commercialize and bring down many of the costs associated with exploitation of shale gas. It is currently estimated that the break-even point to exploit the resources of some key shale basins ranges between \$3.50/mcf and \$7/mcf. The marginal production costs are thus very competitive – partly cheaper than U.S conventional gas production costs- despite being higher than the current costs indicated on the North American market.

A fundamental variable in the cost equation is that the major U.S. shale gas reserves in the Appalachian basin, the Michigan basin, the Illinois basin, the Forth Worth basin and the San Juan basin are found in close proximity to areas of consumption: this is a clear and major factor in the profitability of these shale reservoirs. Availability of access to local pipeline systems and the short distances to consumer markets, in combination with the available service companies and the infrastructure in place, lead to cost reduction in the development of unconventional gas. The cost of fracturing requires it to be done on a large scale to be economically efficient. The cost could be even lowered by another \$1 to \$1.50 per Mbtu if shale oil and gas liquids could be developed simultaneously.

Finally, while the current outlook forecasts costs to fall over the foreseeable future due to technological advances. However, at some point costs are bound to rise again as developers move away from high performance wells and "sweet spots" into more problematic areas due to the increasing number and complexity of hydraulic fracturing required.

COINCIDING FACTORS HAVE HIGH IMPACT ON GLOBAL SUPPLY EQUATION

There is a critical international component challenging shale gas production in the U.S.. The dramatic rise in unconventional gas over the last decade has provided a solution to U.S. supply concerns, but is also affecting global spot gas prices and created one part of the problem. The economic recession, provided the other part, by reduced natural gas consumption globally, but especially in the biggest natural gas market, Europe. Natural gas is evolving from a local, stationary, non-residential commodity, into a mobile, international, primary product similar to crude oil. Almost at the same time, we are witnessing significant changes in incremental flexibility of global deliveries of liquefied natural gas ("LNG"). LNG is natural gas compressed and liquefied for transportation, then decompressed at local delivery stations (or trains). It has been expected through the nineties and in the early 2000 to become a staple supplier to the US and Europe. Today, in the US, the combination of enhanced LNG transportation and delivery capacity increases coming on stream, plus current and expected shale gas supply have changed the gas landscape and resulted in freeing up some previously contracted LNG volumes bound for the US.. Global liquefaction capacity is expected to be up sharply this year and outpace demand for LNG. Meaning that in 2009-2010 an additional nine billion cubic meters (Gm3) extra liquefaction capacity will come online. This is expected to create excess supply in the market with immediate impact on spot market prices and on the need for imports, by both pipeline and LNG. Some contracted LNG will be forced to go to the US terminals, even if demand is not there. [9] Forcing Henry-Hub spot gas prices further down and keeping U.S. near-term prices range-bound ($4-8/mmcf). Thus North American LNG gas prices that are naturally connected to the Henry Hub spot market prices will in effect result in low marginal prices for LNG in other markets like Europe and Asia.

In sum, the combination of three factors, a drop in demand linked to the global recession, an increase in incremental U.S. non-conventional shale gas production, and the arrival of new LNG delivery capacity have together created a sudden abundance of gas supply.

HOW LONG IS THIS GAS BUBBLE EXPECETED TO LAST?

Many observers argue the gass bubble will end in 2013-2015. Why? Because despite the logic that suppliers should reduce production and postpone development plans, a number of factors are aligned indicating continued gas shale drilling plans even in the face of weak US domestic gas prices [15].

First, many gas drilling leases were signed with the condition “drill or lose lease”. Typically these gas leases run for five years, though the contracts are set to expire after three years if the driller does not begin production. Hence, to protect long-term assets, producers chose to drill and produce than forfeit leases. To paraphrase Chesapeake Energy (CHK) CEO Aubrey McClendon, up to 50% of all industry drilling for natural gas is tied to the need to retain leases. According to FBR Capital, this is a factor in several areas, including the Marcellus Shale, the Eagle Ford Shale, and it's most prominent in the Haynesville Shale. [15]

Second, most of the independent E&Ps companies - the pioneers of the onshore shale plays – involved in shale gas exploration and production do not have a refining/marketing arm like the integrated oil majors to serve as a natural hedge. They typically have very aggressive hedging programs in place to protect asset and cash flow. A simple hedge involves buying “futures” contracts to lock in prices. For gas exploration and development companies, hedges in effect guarantee the amount of revenue that companies will receive on a future production, thus giving them some financial stability. As an example, CHK has about 55% of its 2010 production hedged at average NYMEX price of $7.52. In fact, Chesapeake boasts ~$4.8 billion in realized gains from its hedging program since inception in 2001. [15] This past behavior may be modified, given there are currently two proposed bills in Congress intending to limit speculation on future commodity prices. Hedging restrictions (as well as lower existing prices) could also adversely impact available capital for financing new projects.

THE ENVIRONMENTAL ISSUES:

Developing shale gas reservoirs also comes with some environmental controversy: as production has moved into densely populated areas of the US northeast, concerns over the effect of drilling and hydraulic fracturing on drinking water has intensified. Major environmental concerns are over excessive water utilization, drinking water well contamination, and surface water contamination from both drilling activities and fracturing fluids disposal. [2] The industry claims hydraulic fracturing, which involves injecting water laced with chemicals into the shale to break the rock, has no effect on water sources – but environmental groups claim the opposite.

The Environmental Protection Agency (EPA) indicates that chemicals found in water from 11 of 39 wells tested around the Wyoming town of Pavillion in March and May this year may cause illnesses including cancer, kidney failure, anemia and fertility problems. EPA scientists claim that the preponderance of those compounds in the area would be attributable to the oil and gas industry. The water there was discolored, foul-smelling and bad-tasting. There were confirmed cases reported by regulators in Pennsylvania where water has become flammable because methane has “migrated” from drilling into the aquifer. [16]

‘Good oil field practices’ and state-of-the-art techniques should prevent drilling fluids, hydraulic fracturing fluids, or natural gas from leaking into the permeable aquifer and contaminating groundwater. The casing also prevents groundwater from leaking into the well where it could interfere with the gas production process. [2]

The potential for propagating fractures to an overlying aquifer may depend on the depth separating the two. Engineers designing and conducting fracturing jobs have a strong incentive to limit the fractures to the height of the gas-producing shale zones. Any fracture propagated to an overlying aquifer could allow water to flow down into the gas-producing portion of the shale, which could significantly hamper gas production. Afterwards the well operator recovers a large proportion of these fluids by pumping them out of the well, and disposes of them through waste-water treatment plants or by other means as discussed below. [2]

In this stage of production the risk to surficial aquifers is limited; nonetheless, any drilling fluids or fracturing fluids spilled on the ground surface could infiltrate downwards to shallow groundwater could pose a risk. Since each shale gas well is different, as previously explained, the service companies adjust the proportion of fracturing fluid additives to the unique conditions of each well, which is one of the major concerns given that that proportion of each chemical additive is kept proprietary. [2] The majority – 60% to 80% - of the injected fracturing additives returned in flow-back. Typically, it contains proppant (sand), chemicals residue, and trace amounts of radioactive elements that naturally occur in many geologic formations. [17-18] An important question remains: where is the “backwater” stored and/or disposed of

A further risk is naturally existing deposits of methane. Once disturbed by drilling, methane may flow, either up the well or to ground water. This is the phenomenon causes drinking water wells to explode or water from kitchen spigots to catch fire. It is a product of drilling (whether for gas or water), not of the fracturing fluids. It can be controlled by isolating the deposit from the well hole with cement, but this does not always work.

This flow-back causes problems for public owned treatment works (POTW) for the processing of the waste water. Contaminants in industrial process wastewaters can kill off the biota essential to a PTOW´s operation and hence lead to a violation of water quality standards.

In particular, concerns were raised about the large volumes of water needed to drill and hydraulically fracture the shale, and the disposal of this water and other wastewater associated with gas extraction pose significant water quality and quantity challenges that trigger regulatory attention. And there are several other regulatory question marks being raised over the sector in the US. Although, the development of shale gas is already subject to several regulation under relevant federal and state laws including the Safe Drinking Water Act (SDWA) and the Clean Water Act (CWA), and related state requirements. [12] US authorities face a series of difficult choices on gas priorities, which require a more realistic appraisal of the many constraints on capacity development and policies need to adapt to environmental concerns.

Despite all of these constraints, the North American "quiet revolution" on unconventional gas has made unconventional gas development cost lower than in conventional gas projects. Advances in techniques have opened huge U.S. reserves of unconventional gas, and made the country virtually self-reliant in terms of its gas-supply needs. Therefore, shale-gas drilling is unlikely to be stopped for environmental reasons, especially since the oil and gas majors have invested so much.

Conversely, deep shale natural gas uses water primarily during drilling and stimulation, but produces a tremendous amount of energy over the approximate 20-year lifespan of the natural gas well. When compared against other energy resources, it is by far the most water efficient of all the "base-load-level" energy resources, and when used for power generation in a NGCC power plant, is among the most water efficient at generating electricity. [19] Hence, reaching out to the often overlooked fact that compressed natural gas (CNG) is among the water efficient transportation fuels available today. Yet it needs to be taken into account that most of the environmental concerns arise from a lack of environmental stewardship combined with ineffective regulatory framework and monitoring. Thus it is imperative to establish environmental rules, laws and regulations as well as standards for shale gas production which eventually will change and improve the environmental conditions.

Given that the shale gas phenomenon is a game changer in the US, what are the clear and immediate implications for Europe? In the first instance, Europe is benefiting from the price compression and the consequent LNG cargo re-routing towards the EU in the Atlantic basin for consumers in the EU and affects the natural gas prices on the continent.

SHALE GAS IN EUROPE: A REVOLUTION IN THE MAKING?

A number of energy companies as well as policymakers are actively focused on how to replicate and improve upon the North American model of unconventional gas production and use it as a blueprint for reducing European natural gas import dependence. The IOC´s – who at large missed out on the first stage of shale growth in the US – are fulfilling a land grab encouraged by cheap acreage prices and a solid resource estimate in the EU. As the EU continues to promote self-sufficiency and security in energy, it places much hope in unconventional gas and the possibility that it will radically change the supply outlook for natural gas within a few years, as it has done in North American context.

Currently, three major potential shale gas Paleaozoic plays have been identified: the Cambrain-Ordovician (stretches from Denmark through to Sweden), the Silurian (Poland) and the Carboniferous (runs from the UK through to Poland).

Both the European Commission and the IEA believe these and other basins could be depositories of significant resources with estimated total recoverable reserves in Europe that fall between 33 to 38 TCM, of which 12 TCM are tight gas, 15 TCM shale gas, and 8 TCM coalbed methane. Such sizable resources have the potential to radically reshape the picture of European´s gas supply and shale gas could thus play a key balancing role in gas markets on a regional basis.

Several questions remain as to how these unconventional resources can transform the European market. These include concern over organic content, shale pressure, and mineralogy, all of which result in risk to any forecast.

DIFFERENT MARKET STRUCTURES AND FUNDAMENTALS ARE CORE CHALLENGES:

Several obstacles lie ahead of efforts to commercialize shale gas in Europe, starting with acute environmental concerns in Europe. The constraints connected to water can be summarized in two categories; one is the environmental concern, that fracturing of shale contaminates fresh water supplies and the other is connected to scare water availability for drilling.

To avoid contamination of aquifers through drilling and to obey the strict environmental regulations of most European countries wells are drilled with multiple casing strings, and the shallowest ones isolate the fresh water aquifers. Fresh water aquifers are generally found at depths that are 1,500 to 2,000m+ shallower than the productive shales. In comparison to other fossil fuels, for example coal, the environmental damage done by lignite mining and also its impact on aquifers is tremendous.

With further technology improvements and potential to develop of more environmentally-friendly drilling technologies the oil and gas industry will find a way to cope with many of the water issues related to drilling, and will reduce these obstacles over time.

The other underestimated obstacle connected to water is the scarcity of availability of water. The very large volumes needed to unlock shale gas from rock formations will compete for water with the agriculture industry. Potentially millions of gallons of water per well are needed for fracturing operations. Sourcing of such large quantities of water in areas where water is scare and environmental regulations apply to large areas of the land will be an obstacle to unconventional gas development. It is often overseen in these allegations that in most shale plays 70% of fracturing water can be re-used and therefore drastically reducing the amount of water needed. In addition, where ground water is not present technology improvements now make it possible to use water from brackish aquifers. [20]

Public reticence in acceptance of, water and air pollution around gas rigs and compressor stations, and the environmental surface footprint with drilling pads and new roads in place are significant obstacles, especially in Europe's dense populated areas.

This leads to the next anticipated obstacle, that shale gas production requires hundreds and thousands of square kilometers, compared with tens or hundreds needed for conventional gas development.

In Europe, this will be very problematic since the population density will require negotiations for getting production rights and access to land will entail talking to hundreds of landowners. As an illustration in Poland one million farms are averaging only twelve acres in size.
Allocation of property rights is very different in Europe compared to the U.S.. In North America the owner of the land also owns the subsoil with its resources underneath and she/he receives revenues which give important incentives for landowners to allow gas drilling and production on their land. In contrast, in Europe it is common that the state own land rights and states receives royalties. Hence the owner of the land does not own the subsoil, and exploration and production companies must therefore negotiate with the subsoil owner (the state in most cases) and the land owner, which renders the process considerably more complicated. This has two major implications for the public opinion, which is central. First, since the landowner does not receive revenues from drilling, the incentive to accept the inconvenience is less given. Second, arriving from the first fact is that local opposition of an ecologically sensitive public in Europe is opposed to onshore drilling if the profit for local communities is not given.
This will lead to a rash of NIMBY (not-in-my-back-yard) opposition to shale-gas drilling. This is not unlike the development in the U.S., where environmentalists have raised objections to the rampant growth of the unconventional-gas sector. As an example, in October, Chesapeake, one of the largest shale-gas drillers in the U.S., decided it would not drill in an area of New York State after opponents claimed its operations could endanger the watershed. [21]
Over time, improvements and more investments going into horizontal drilling and fracturing give the possibility to reduce the number of well pads needed. New well and drilling technologies will continue to increase the lateral lengths that can be drilled. This means, that long laterals can be drilled in multiple directions from single surface locations. Given this fact, as many as 8 to 12 wells can be drilled from each pad to drain gas from a large area. Therefore the technological improvements are expected to reduce not only the surface footprint but also the need to negotiate with all landowners.

ECONOMICS

A major challenge to develop unconventional gas is the entrenched economics of conventional gas. Conventional remains the cheapest favoring gas imports through an already in place transport infrastructure which brings heavily reliant on one supplier and has produced an extreme view of supply security.

The fact that shale gas has lower productivity than conventional gas and production declines faster in the first years of production adds further economic constraints. This means that a larger number of wells will be needed to keep up production. These wells require horizontal drilling and hydraulic fracturing, which makes the wells more expensive again. Even though, the well will then keep producing for some decades as mentioned earlier, but how expensive shale gas is to produce will technically depend on the shale characteristics.

Although, European geology is sufficiently well documented, rock formation, abundance of shale gas, and the cost of production remain crucial issues. Some of the reserve estimates come from studies that were done in the late 90s, [9] but the potential of rock properties and geologic structures has yet to be confirmed. What is know so far is that geology is more disturbed and fragmented, where the strata of rock have over the eras folded back on themselves creating faults, thus complicating the drilling and appraisal process.

Until test wells are drilled in each prospective shale gas basin, it is impossible to know whether any individual project will be economic or not. Low gas prices in the U.S. will ensure continued acceleration of technological advances, which will increase efficiency and improve economics even further. [20] Especially, if you take into account that we are talking about a development period of five to ten years.

One myth that often comes up is that European shale is deeper underneath the surface and probably lacks sedimentary basins of the scale of those of the US. Conversely, shales in Europe are found at a wide variety of depths, numerous shales go from outcrop to various depths just like in the U.S. The Fayetteville produces from 1200 m and Haynesville at 4000 m. In Europe, Shell is testing the Alum shale in Sweden at 900m while we are targeting shales in the Baltic Basin between 2,500m and 4,000m.[20] Also some of the European shale is thought having more gas stored than the shale found in the U.S.. Moreover, some of the most promising European shale’s are offshore in the North Sea, and offshore production of shale gas has not been tried yet, which is more likely an issue of economics than of technology. [9]

Thus, additional economic constraint comes from the fact, that unconventional gas exploitation is at an embryonic stage and needs further development. And while Europe's gas-distribution infrastructure is well developed, the services sector that would support an unconventional gas industry is not. But subcontractors are already gearing up for the anticipated level of activity. Supplementary, Europe also lacks of technical equipment like suitable drilling rigs. [21] According to Baker Hughes rig count of May 2010 Europe accounted for 46 Land and 42 offshore rigs making up to a total of 88 (57 oil / 23 gas / 8). Most of these rigs are unsuitable for shale gas necessary types of drilling and hydraulic fracturing operations, but there are sufficient rigs to drill the science wells. Poland, for example, which prospects are believed to be in similar depths to those in Texas' Barnett Shale there are just seven operational rigs suitable for shale exploration. Rig transfers within the EU would be easiest but this would equate to only 46 land rigs, which are unlikely to be suitable for horizontal and fracturing operations, especially if polish shale is over pressured as believed. Compared to the U.S. having 1513 total rigs in place from which 1464 where onshore, the majority of it used for unconventional drilling and 49 for offshore drilling. [22]

It is often stated, that this makes Europe either dependent on importing equipment from North America or China. Although, U.S. imperial rig measurements provide further scope for delays due to mismatches with European metric standards. Also, European import requirements and regulations make it challenging to simply import rigs from aboard and this creates a bottleneck for both rig access and service. This might be either a chicken-and-egg issue which can be overcome by time. Europe has excellent engineering and skilled workers that will take the U.S. knowledge, and likely improve upon it, with rigs being built to European specifications within 9-12 months as needed. [20]

Besides that, the regulatory issues and the current market structure have some obstacles in place. Nevertheless a regulatory system with potential tax credits to help push unconventional-gas development will evolve only as the companies demonstrate the commercial viability of their plays. Most of the pipelines in Europe are still not independent but are affiliates of major national producers, which have an impact on their operations and strategies. The ongoing liberalization process and need for a deregulated European market brings several uncertainties even to conventional gas production and long planned investments. [23]

The long-term import contracts are also a major obstacle for new sources of gas finding its way into the market. Were new unconventional gas is rather going to depress the spot price for the little spot trade that is there. Unconventional and additional LNG gives also more flexibility and liquidity to the trading hubs and spot pricing. [24]

HIGHER COST OF DRILLING

Given the infancy of the sector in Europe, we can expect initial production cost are much higher; drilling costs for Europe is currently between two to four times more expensive on a unit cost basis than the U.S.. Labor cost is significantly more expensive than in the U.S.. Adding up additional costs, and with less competition in the services sector, there are fewer drivers to bring down the price of development. Wood Mackenzie's predicts the break-even price for shale gas in

Europe would be around $9/m Btu, or almost twice the price of gas in the U.S. at present. [21] According to Oxford Energy, the cost of producing shale gas in Europe will be up to four times the one in U.S.. Experts say U.S. costs of production are in the range of $2 and $6 or $7, which means costs of $4 to $28 per mbtu in Europe.

On the other hand, Europe's market is well developed and flexible enough to reward new suppliers. With high and stable oil-linked gas import prices, shale gas production can be very lucrative. So where the average import price on the German boarder was around $8.52 per mbtu in 2009 and the average NBP spot marked price in the UK was $4.85 per mbtu.

As long as European suppliers hold onto the oil-price index that governs prices for long-term gas-supply contracts, the gas market will follow crude. Gas prices estimate for 2012 are to reach $9/mmcf – 70% of which is contributed by the 9-month trailing Brent price and the remaining 30% from government subsidies, meaning that the break-even gas price will also be much higher in the EU. [21] Despite projections for abundant gas supply in the next three years, this means that the price would be even sustainable to pay for the higher capex cost for unconventional gas development in Europe related to the lack of operational efficiencies from a smaller drilling network. Beyond the strategic rationale for bringing new supplies on stream, should offer a commercial rationale for developers. [21]

A TOUGH NUT TO FRAC

As demonstrated, existing economic constraints and obstacles in Europe make the cost and the development risk for shale much higher than in the U.S., although the exploration risk is low. Even when the geological, environmental hurdles can be overcome, economic concerns, like production cost and gas pricing issues may even be greater. That said there remains an upside from expected rising trend in domestic gas pricing and by relative attractive fiscal terms. Several test wells which will be drilled this year will shed some light on some geological uncertainties and by the end of this year we may have a better idea of “Doctor Drill´s” preliminary estimation on that issue. Yet even if Europe's shale-gas potential is realized, it probably will not happen - for the next ten years as the Petroleum Economist states - before the entire planned, new import infrastructure to supply the continent's forecast demand is built. [21]

GAME-CHANGER, OR NOT?

Having elaborated facts of shale gas development in the U.S. and compared the fundamentals, different economics and therefore core challenges for unconventional gas development in Europe can be drawn. Now, it is time to answer the remaining question: is shale gas a game changer, or not?

To what extent shale gas will change the game in Europe remains unclear; however, with the restructuring efforts in the European markets, unconventional gas development will be a key element to the energy agendas of many member states, especially Central/ Eastern European market. The playing-out of the environmental issues in more densely populated Europe will be also a key factor to watch in assessing the potential of shale gas in Europe. European energy is facing opportunities and challenges in terms of policy changes, short of up to date technology and equipment, capital introducing and market norms.

So, is shale gas a game changer, or not? Some of the experts, geologists and industry representatives say it will be: some of them say it won´t. In my opinion, shale gas has certainly changed North America´s natural gas market; and within the evolving global natural gas market it has a causal effect on all markets and in particular on the European market. Shale gas enabled the U.S. to remove its energy dependency and furthermore reduce nearly all of its LNG import needs. In combination with economic recession, this lead to an oversupply of the international LNG market with strong downward pressure on gas prices around the world. Despite how European unconventional gas develops, the shale gas evolution in the U.S. has changed the international and first of all the European gas market. Yet, shale gas has yet to change the energy balance in Europe, and it is not clear if it will materialize before 2020, although it has become a game changer on the European gas market.

The U.S. shale gas boom enabled a revolutionary domino-effect on the European LNG market, the contractual structure of the hitherto dominated by 20-years long term take-or-pay contracts and lead to re-negotiations of some of the oil linked natural gas prices. Therefore, shale gas is having an increasing influence on European gas prices and it is anticipated that it will continue to do so through 2015.

Regardless of how the outlook on European unconventional gas development looks, and whether or not unconventional gas will become affordable and sustainable in the mid-to-long term in Europe, shale gas has changed the European market even before a single well has been drilled, or a single molecule of unconventional gas has been produced in the European basins.

APPENDIX I

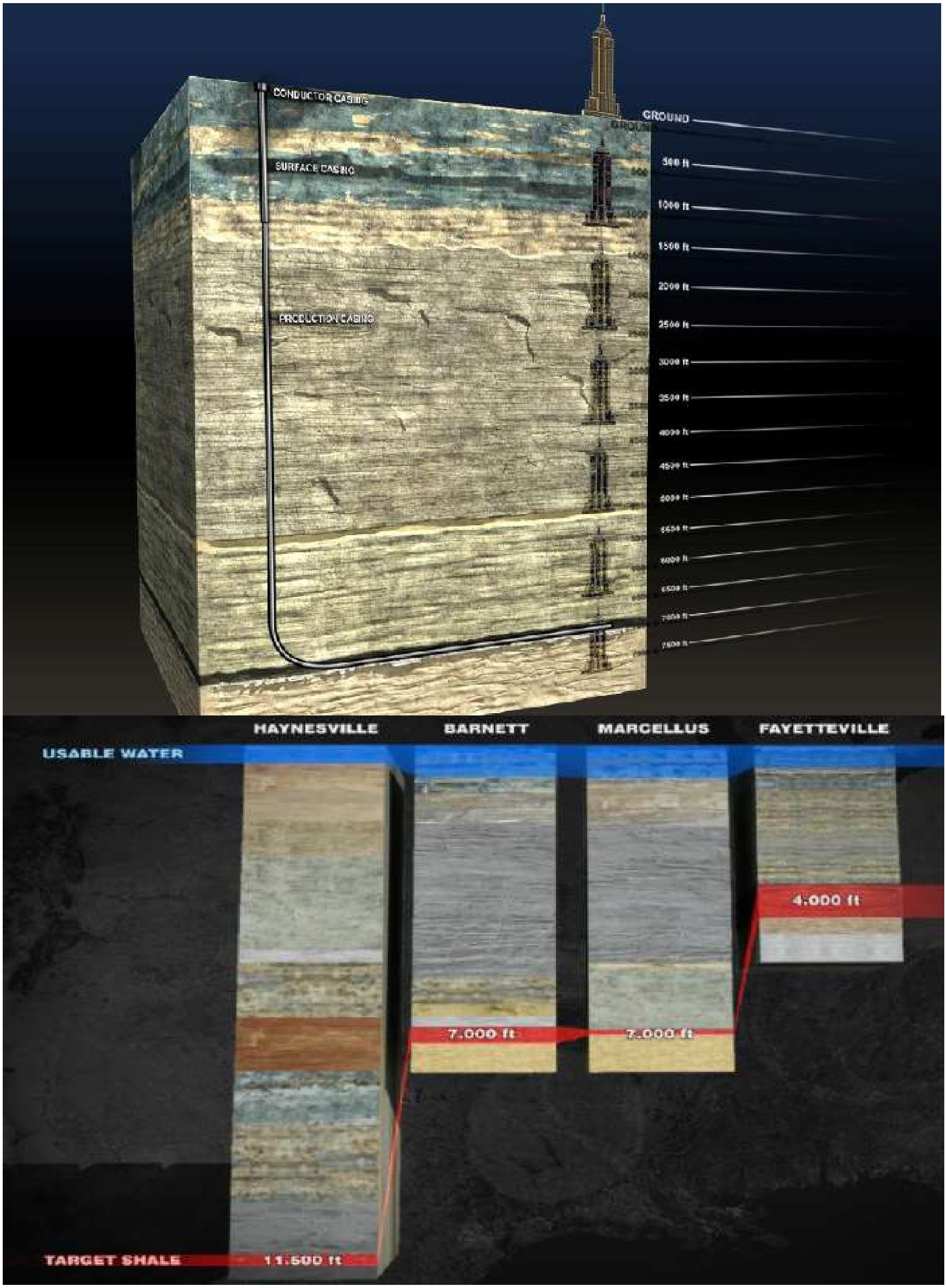
Comparison and Differences between the U.S. and European unconventional gas possibilities

US shale	European shale
• Many 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

European shale gas unit cost typically double that of US shale gas			
Location	**Average Gross UR per well (Bcf)**	**Average Well Cost (US$m)**	**Unit Cost US$/mcf)**
Shale gas - US	3-6	6	1.0 – 2.0
Shale gas - EU	3-6	15	2.5 – 5.0

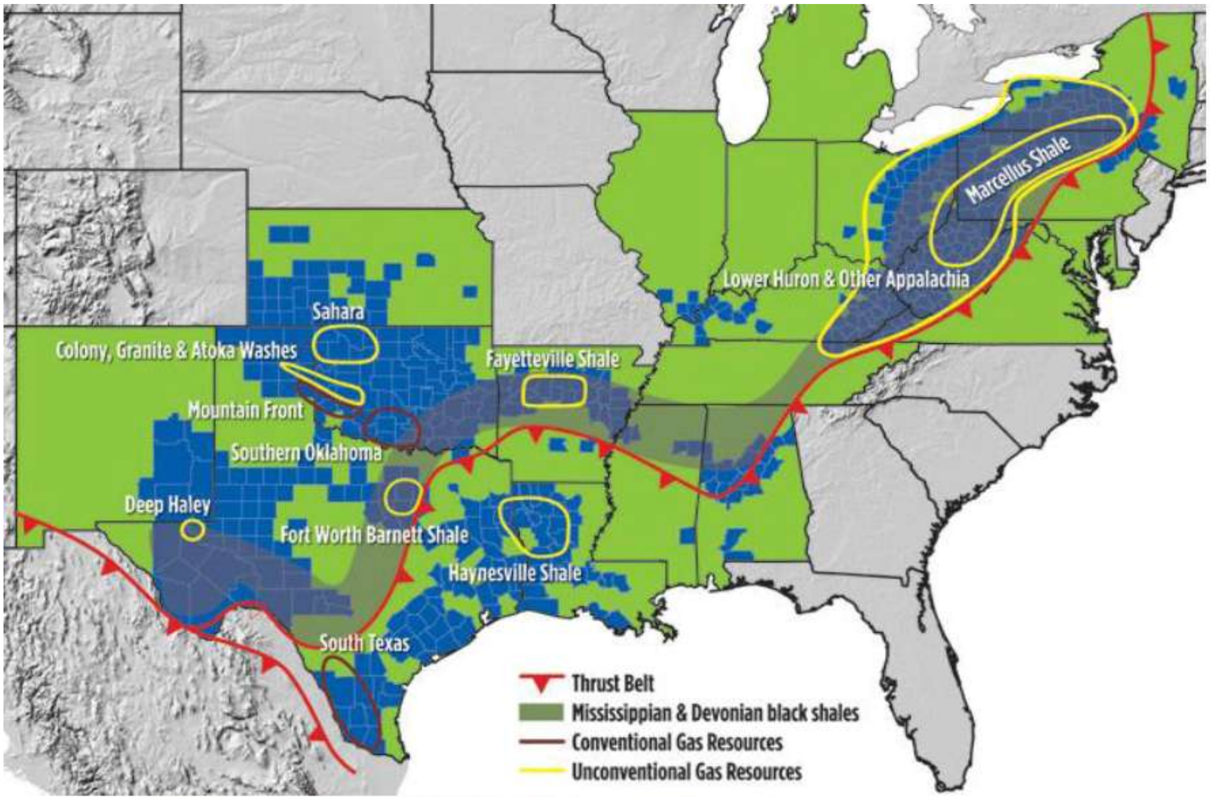
Source: various news and company resources, own compilation

Horizontal drilling and target depth of major U.S. shale plays



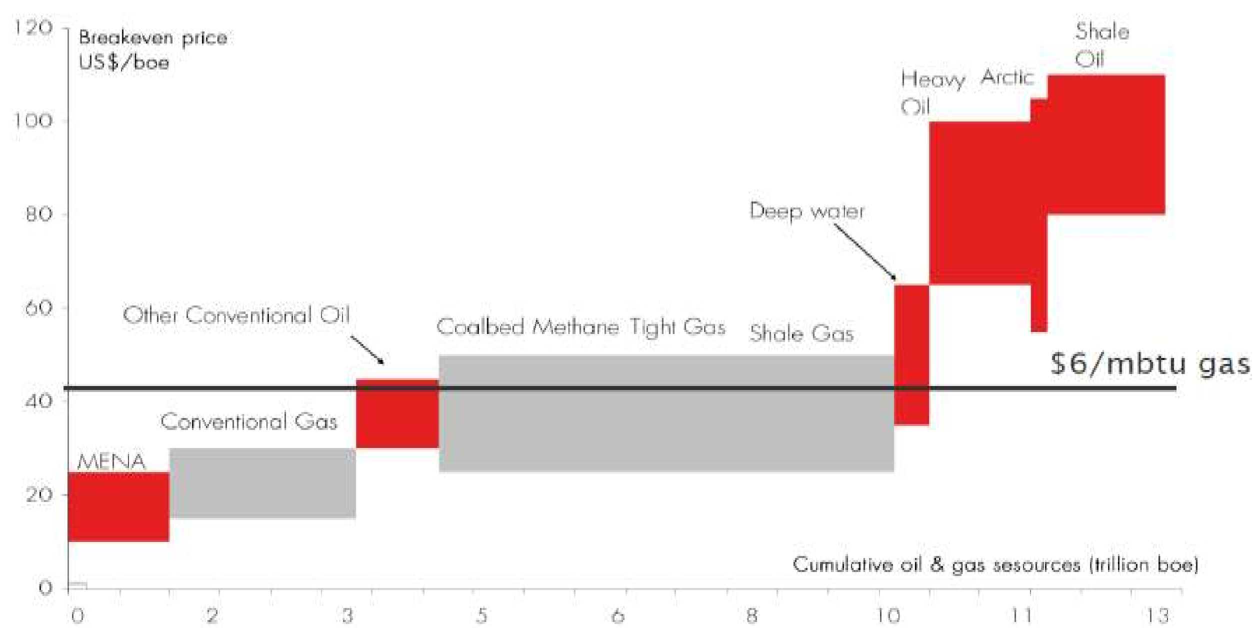
Source: The “Big 4” Shale Plays:Usable Water vs. Target Depth; Chesapeak [25]

Shale gas fields in the US



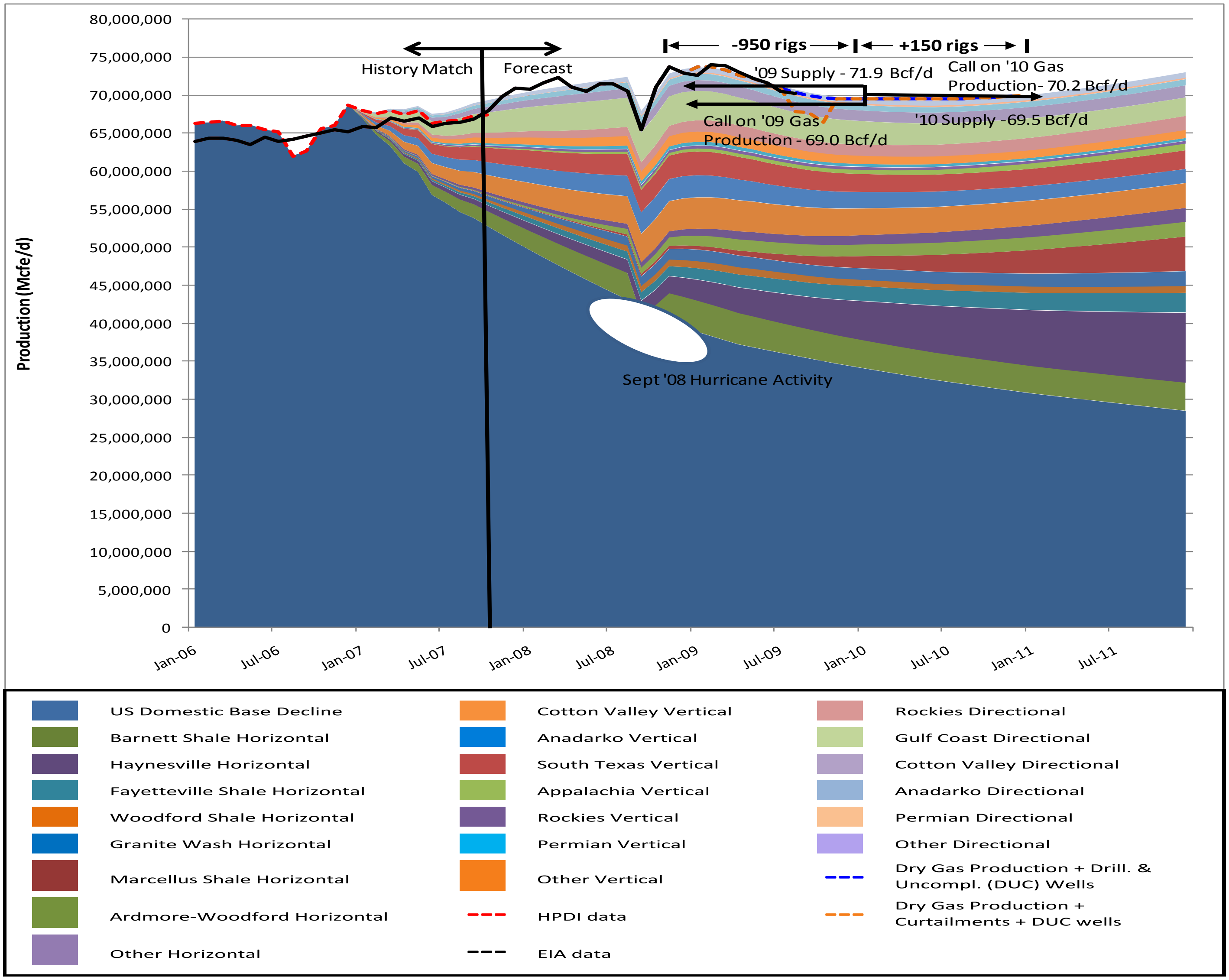
Source: Chesapeak [25]

Breakeven prices conventional and unconventional gas



Source: IEA, USGS, Nomura Equity Research

US gas production growth

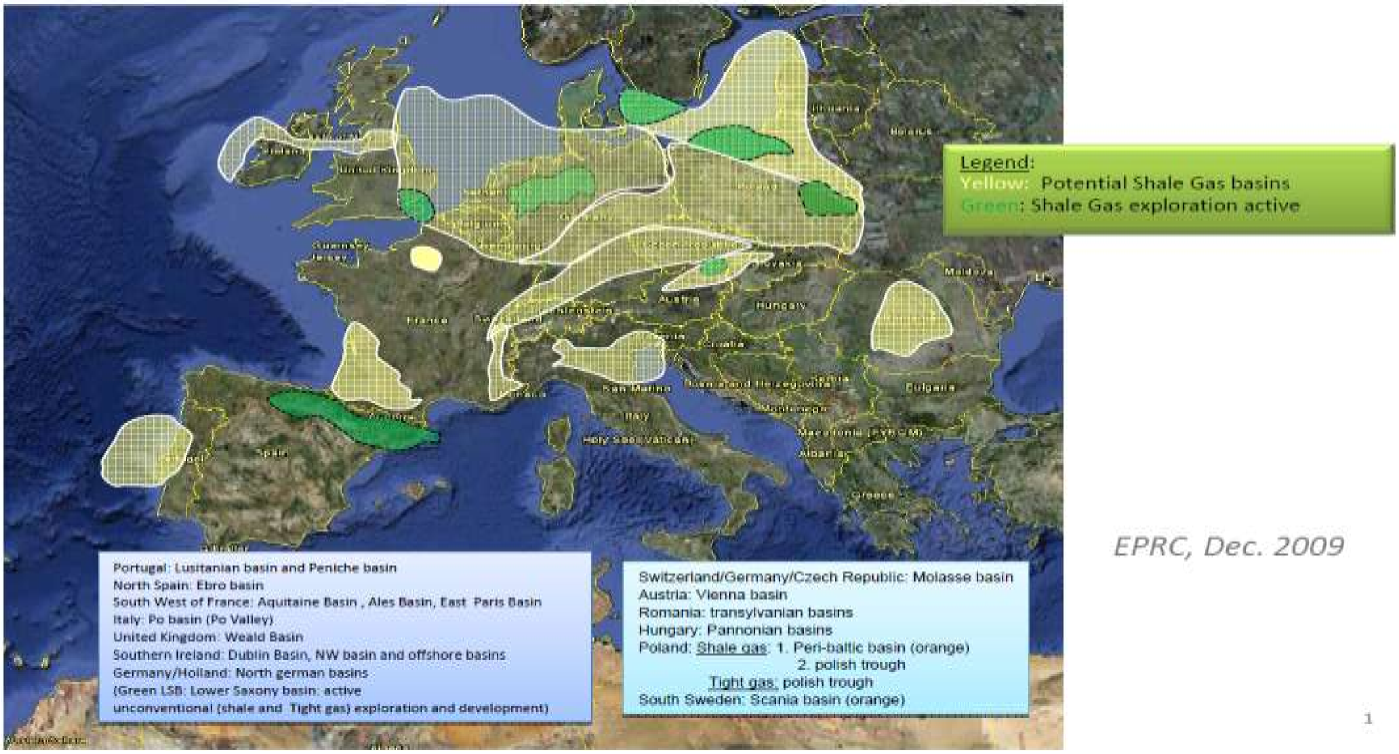


Source: various data reports and company resources

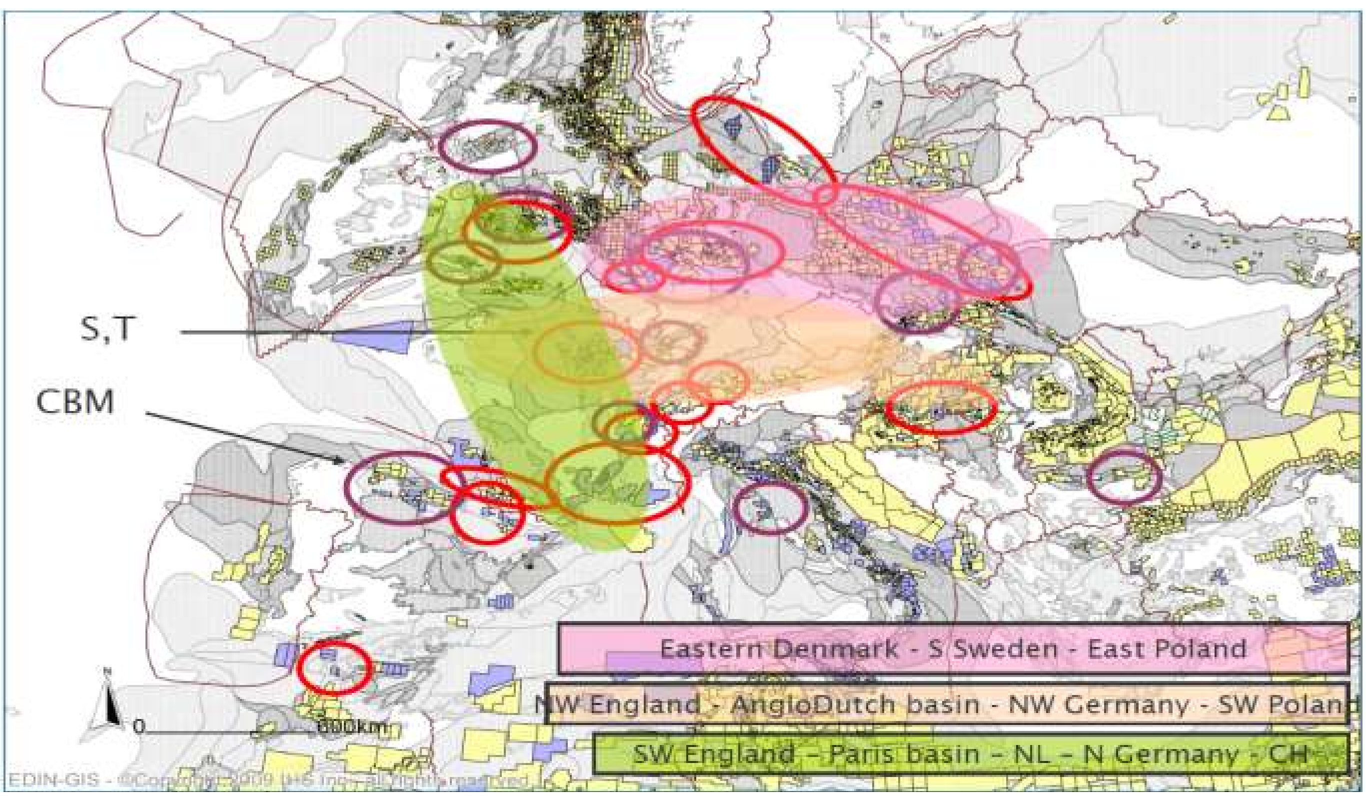
	Shales								Tight Gas						CBM			
Metrics	Marcellus (dry)	Horn River	Eagle Ford	Fayetteville (core)	Barnett (Core)	Haynesville	Woodford	Anadarko-Woodford	Jonah/ Pinedale (vert)	Granite Wash	Piceance (vert)	James Lime	Uinta (vert)	CV (vert)	Nora CBM	Raton	Powder River	San Juan
Cost per Well ($MM)	$3.7	$10.0	$5.0	$3.1	$2.8	$7.5	$5.0	$8.0	$5.3	$6.0	$1.6	$2.7	$1.7	$1.7	$0.4	$0.5	$0.3	$1.9
EUR per Well (Bcfe)	3.5	10.0	5.5	2.6	3.0	6.5	4.0	8.1	3.9	6.4	1.0	2.0	1.2	1.0	0.4	0.6	0.3	1.4
Royalty (%)	15%	15%	25%	20%	25%	25%	15%	20%	15%	15%	17%	20%	17%	20%	15%	15%	13%	17%
F&D Cost ($/Mcfe)	$1.24	$1.18	$1.22	$1.48	$1.23	$1.54	$1.48	$1.25	$1.60	$1.11	$1.87	$1.71	$1.71	$2.18	$1.20	$1.15	$1.16	$1.72
IP Rate (MMcf/d)	3.5	8.2	9.0	2.8	2.5	14.0	3.6	6.0	5.0	7.5	1.0	5.0	1.2	1.0	0.04	0.09	0.04	0.14
Differential (%)	3%	-15%	12%	-8%	-8%	-2%	-8%	-8%	-18%	-8%	-15%	-5%	-15%	-7%	3%	-15%	-15%	-15%
LOE ($/Mcfe)	0.90	1.00	0.95	0.70	0.90	0.85	0.80	0.75	0.70	0.80	0.85	1.06	0.85	0.92	0.70	1.61	2.50	1.05
G&A ($/Mcfe)	0.55	0.55	0.55	0.00	0.00	0.55	0.00	0.00	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55
Production tax (%)	5%	5%	5%	5%	8%	33%	7%	7%	6%	8%	6%	2%	6%	2%	3%	12%	12%	13%
1st Yr Decline (%)	-62%	-65%	-82%	-64%	-65%	-85%	-59%	-58%	-76%	-72%	-58%	-86%	-63%	-67%	66%	57%	214%	254%
2nd Yr Decline (%)	-35%	-34%	-41%	-35%	-34%	-41%	-43%	-34%	-35%	-37%	-35%	-46%	-34%	-33%	-7%	0%	11%	11%
3rd Yr Decline (%)	-21%	-19%	-22%	-21%	-19%	-26%	-32%	-22%	-9%	-30%	-22%	-35%	-16%	-18%	-9%	2%	8%	-4%
Out Yr Decline (%)	-5%	-6%	-5%	-5%	-6%	-5%	-5%	-6%	-10%	-6%	-5%	-6%	-6%	-7%	-6%	-5%	-18%	-17%
Threshold Price ($/Mcfe)	$3.85	$5.25	$4.10	$3.95	$4.10	$4.90	$5.00	$4.50	$5.75	$4.40	$5.70	$5.03	$5.80	$6.65	$5.20	$6.00	$6.50	$6.25

Source: Various Company reports

Some major European unconventional gas basins I



Some major European gas basins



Source: EDIN-GIS HIS CERA

Land Access - Barnett shale gas field; TEXAS, US

Land Access – Poland compared to US

Source: GoogleMaps

Fiscal terms in Central and Eastern Europe			
Country	**State Participation**	**Income Tax rate**	**Royalty**
Poland	None	19%	5.63 PLN (1.25EUR)/mcm
Romania	None	16%	3.5%-13.5%
Bulgaria	None	10%	2.5%-30%
Slovakia	None	19%	5%-10% of revenue

Source: various news and company resources, own compilation

WHO IS DRILLING IN EU

European unconventional gas plays			
Country	**Basin**	**Companies involved**	**Comments**
Austria	Vianna basin	OMV	15 tcf of gas potential identified in deep Vienna basin, testing shale gas in 2009-10
France	Bresse basin Lorraine basin, Nord pas-de-Calais, Paris basin, Southeast basin	Devon (DVN), East Paris Petroleum Development, European Gas Limited (EPGAU), Mouvoil SA, Bridgeoil Ltd, Diamoco Energy, Lundin Petroleum (LUPE), Toreador Resources (TRGL), Total (FP) EurEnergy Resources	Companies seeking permits in various basins
Germany	Lower Saxony basin Bodensee Trough	ExxonMobil / Wintershall Royal Dutch Shell (through partnership in BEB with ExxonMobil) 3Legs Resources	XOM plans 10 wells on 750k acres 2009-10
Hungary	Bekes basin, Mako trough Penezlek	MOL / Exxon / Falcon Oil (FO) Ascent Resources (AST LN)	Completed tree disappointing hydraulic fracture tests within the Szolnok Formation on the Foldeak-1 well
Netherlands	Central Graben, Vlieland London-Brabant Massif; West Netherlands	Exxon / Shell Cuadrilla Resources	Hold licenses
Poland	Polish basin, Timan-Pechora Baltic-basin Suliran shale (shallowest 1-2km depth)	3Legs Resources, BNK Petroleum Inc. (BKX), ConocoPhilips (COP), Aurelian Oil & Gas (AUL), Talisman (TLM), San Leon Energy (SLE), 3Legs Resources Lane Energy / Sorgenia E&P, BNK Petroleum, EurEnergy Resources, RAG,	Preliminary data shows potential for shale gas. First well to be drilled May 2010 Will drill two horizontal appraisal well program commencing June 2010 on Siekierki Gas field seismic planned this year and TLM has committed to drilling three wells as part of farm-in deal
		RWE	
		Marathon Oil Corp	
		Chevron	
		Exxon Mobile	
Sweden	Alum shale Fennoscandian Border; Baltic Depression	Royal Dutch Shell	Owns licenses, 3 year exploration project in Skane. 3 well programs planned for 1Q 2010
Switzerland	Alpine Foreland basin		
Ukraine	Dnieper-Donets	Maraton, Naftogaz Ukrainy (NAK), JKX oil & Gas (JKX), Regal Petroleum (RPT), Cadogan Petroleum (CAD), Transeuro Energy (TSU)	MRO and NAK signed an agreement in June 07 to explore Dnieper-Donest basin. Other companies mentioned have interests in the basin or the vicinity
UK	Kincardine basin, Scotland (CBM) Cheshire basin, North west England	Composite Energy / BG, Island Gas (IGAS LN), Nexen (NXY CN), greenpark Energy, Marathon, AJ Lucas, Cuadrilla Resources, EurEnergy Resources,	3000ft depth, 40ft pay Total resources of 4tcf in Cheshire basin (WoodMac). First CBM production in June09 from IGAS Doe Green site

Source: various news and company resources, own compilation

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