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The Potential of Unconventional Gas – energy bridge to the future
(with a review of European unconventional gas activities)

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Keywords: Unconventional gas, shale gas, coal seam gas, tight gas, European gas, waste zones, unconventional hydrocarbons, methane, horizontal drilling, hydraulic fracturing, gas reserves, Russia, global gas resources, reach of gas resources.

Contents

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Abstract

The aim of this paper is to give an overview of the potential and challenges of unconventional gas exploration and development and show its impact on the future word energy supply. Special emphasis is placed on European activities. The paper focuses on coalbed methane, tight gas and shale gas only since gas hydrates, though having enormous in-situ volumes, have yet to prove economically viable.

The magnitude of the new unconventional gas opportunities is due the fact that hydro-carbon-generating basins are highly inefficient systems. Most of the oil and gas produced never leaves the source rock and even of the expelled volumes only a small fraction eventually fills the conventional traps, explored to date. The remaining hydrocarbons have leaked out of the basin or are still stuck in the system in low permeability rocks. These «waste zones» are the target of the unconventional exploration and they can only be produced through advanced technology, such as horizontal drilling and extensive stimulation by hydraulic fracturing.

In Europe, the technology has come under considerable criticism for alleged groundwater pollution, induced seismicity and excessive water use. Factual information shows that many of these claims are highly exaggerated and that the risks can be mitigated by good operational standards. Europe has considerable potential but, for reasons of population density, limited capacity of the service industry and environmental concerns, European unconventional gas development is unlikely to experience the dramatic rate growth observed in the US.

Conservative estimates put the global unconventional gas resources at up to 50% of ultimately recoverable conventional gas. This is most likely conservative and many experts carry much larger figures. At present rates of consumption, the total global gas resources provide supply potential for between 170 and 300 years. Within few years, unconventional gas has fundamentally changed the outlook for the future US energy supply and mix. A similar development, albeit at a slower pace, is expected to take place in the rest of the world. Natural gas is today the principal source of hydrogen production and hydrogen fuel cells may become a clean, common and decentralized energy source, also for mobility. Combined with a global gas supply that is virtually unlimited in the medium term, this could lead to a methane-driven economy, and provide us with the necessary bridge to a renewable energy world.

Zusammenfassung

Die Publikation gibt eine Übersicht über das Potenzial und die Herausforderungen von Exploration und Entwicklung von unkonventionellem Gas und zeigt die Auswirkungen auf die zukünftige Weltenergieversorgung. Die Aktivitäten in Europa werden im Detail behandelt. Der Fokus gilt dem Kohleflözgas (coalbed methane), «tight gas» und dem Schiefergas (Shale Gas). Die ebenfalls unkonventionellen Gas-Hydrate bilden zwar riesige in situ Vorkommen, sind aber noch weit von einem Nachweis wirtschaftlicher Produktion entfernt.

Das sehr grosse Potenzial von unkonventionellem Gas hat seinen Ursprung in der Tatsache, dass Kohlenwasserstoff generierende Sedimentbecken sehr ineffiziente Systeme sind. Der grösste Teil des generierten Öls und Gases bleibt im Muttergestein gefangen und selbst von den austretenden Kohlenwasserstoffen erreicht nur ein kleiner Teil die konventionellen Fallen, die bisher exploriert wurden. Der Rest ist an der Oberfläche erodiert oder verdunstet oder ist in dichten, wenig durchlässigen Gesteinen des Beckens stecken geblieben. Diese «Wastezones» sind das Ziel der unkonventionellen Exploration und sie können nur mit speziellen Techniken wie Horizontalbohrungen und extensiver Stimulation durch hydraulisches Aufbrechen des Gesteins gefördert werden (hydraulic fracturing).
In Europa sind diese Methoden wegen angeblicher Grundwasserverunreinigung, induzierter Seismizität und zu grossem Wasserbedarf in die Kritik geraten. Die Fakten aus den USA zeigen, dass diese Anfechtungen stark übertrieben sind und dass die Risiken mit guten operationellen Standards weitgehend ausgeschaltet werden können. Europa hat ein erhebliches Potenzial für unkonventionelles Gas, aber eine grössere Bevölkerungsdichte, beschränkte Kapazität der Service-Industrie wie auch Umweltbedenken, verhindern vorderhand eine ähnlich dramatische Entwicklung wie in den USA.

Konservative Schätzungen zeigen, dass unkonventionelles Gas global mindestens 50% der endgültigen konventionellen Volumen erreichen kann. Dies ist vermutlich sehr konservativ und viele Experten erwarten wesentlich grössere Volumen. Gemessen an der heutigen Gasproduktion ergeben die geschätzten totalen globalen Gasreserven eine Reichweite von 170 bis 300 Jahren. Unkonventionelles Gas hat in den letzten Jahren die Prognosen für die Energiezukunft und den Energiemix der USA drastisch verändert. Eine ähnliche Entwicklung, ist verzögert für den Rest der Welt vorhersehbar. Erdgas ist zurzeit der wichtigste Rohstoff für die Wasserstoff-Produktion und Wasserstoff-Brennstoffzellen könnten in den nächsten Jahrzehnten zu einer weit verbreiteten Quelle von dezentralisierter, sauberer Energie werden. In Anbetracht der mittelfristig fast unbegrenzten Gasreserven kann dies zu einer Methan-getriebenen Wirtschaft führen und könnte uns die nötige Brücke liefern zu einer längerfristigen Zukunft mit erneuerbarer Energie.

1. What is unconventional gas?

There is no formal definition of unconventional gas. Usage of the term has varied over time and with context. There are three types of unconventional gas: geologically unconventional accumulations of fossil natural gas (resource plays; «difficult to produce»); gas sourced from synthetic manufacture (e.g. by gasification of coal underground); gas from non-fossil sources (e.g. landfill gas). In this paper only geologically unconventional accumulations of naturally occurring fossil hydrocarbon gas are discussed. The mode of occurrence of these unconventional gas plays is illustrated in Fig. 1.
Resource plays have also been described by the US Geological Survey (2000) as «continuous-type deposits» but within industry the use of the term «resource play» is more common. In a gas resource play, natural gas is pervasive throughout a large area that is not significantly affected by hydrodynamic influences and that appears to lack well defined down dip water contacts. Historically, gas accumulations that were difficult to produce and which were formerly marginally economic or non-economic because they require distinctive completion, stimulation, and/or production techniques to recover the resource, were also regarded as unconventional.
Unconventional natural gas can exist in different states. In tight gas, the gas exists as free gas contained within the porosity of the reservoir rock (sandstone; limestone; chalk). Shale gas has a mixed system, with some gas existing as free gas in fractures and micro pores and some gas adsorbed on kerogen and clay mineral particles. In coal seam gas reservoirs, most gas exists adsorbed on coal surfaces with a lesser amount occurring as free gas in micro pores and fractures. The gas in natural gas hydrates is contained in yet another form, that of clathrates, in which cages of water molecules surround gas molecules giving rise to a white ice-like substance. Gas hydrates can only occur in

polar or high-altitude permafrost regions or in oceanic sediments or deep inland seas where the water temperature is close to 0° C and the water depth exceeds 300 m. In Europe, subaquatic gas hydrates have been reported offshore Norway and from the Black Sea but are not discussed further in this paper.

Some commentators have suggested that reservoirs in which gas occurs only as free gas should not be termed unconventional. For example, Sahay & Van Dyke (2010) have suggested that only reservoirs which are also the source rock and in which at least some of the gas is trapped by adsorption on the source organic matter should be termed unconventional gas reservoirs, thereby excluding tight gas reservoirs in which the gas occurs only as free gas. There is a certain logic to this as some tight gas accumulations undoubtedly occur in conventionally trapped reservoirs and the production of progressively tighter reservoirs has developed steadily over time as completion technology has improved, thereby making the boundary between conventional and unconventional hard to define. But not all tight gas reservoirs appear to be conventionally trapped and there is one feature that is shared by tight reservoirs, shale reservoirs and coal seam reservoirs, namely that the maximum micro pore diameter through which gas molecules must flow to the producing well is of the order of 1 μm (micron) (Lovell et al. 2010). As a result, tight gas reservoirs come into the category of «difficult to produce» reservoirs that can only be developed by employing much of the same technology that is required to produce shale gas reservoirs and, to a lesser extent, coal seam gas reservoirs.

1.1 Technology

The key to the dramatic increase in unconventional gas development over the past two decades lies in these technological developments: the ability to drill laterally within a relatively narrow rock unit for thousands of metres and the ability to fracture the surrounding rock from within these extended reach «horizontal» wells multiple times. In Canada's Horn River Basin for example, shale gas wells with lateral lengths of 3,000 m and over 20 fracture stages per lateral are now normal.

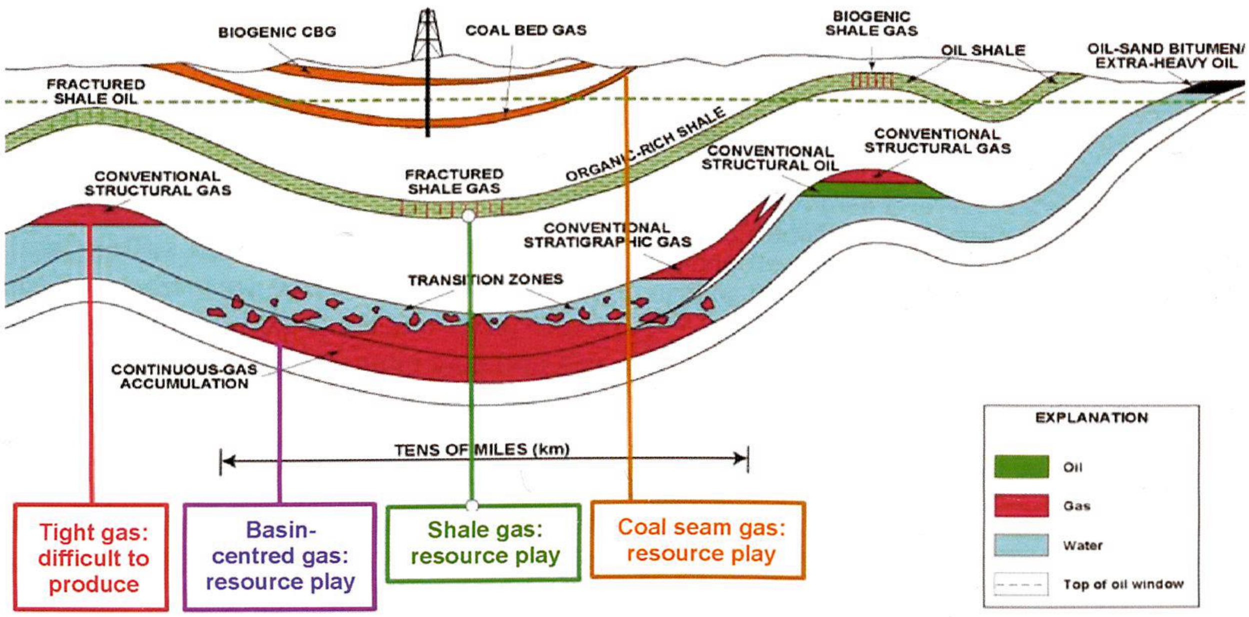

Fig. 1: Occurrence of conventional and unconventional hydrocarbon liquids and gas (with unconventional gas accumulations highlighted).

Popular concerns about the impact of hydraulic fracturing on drinking water supplies and local seismicity have been raised in a number of European countries (e.g. Netherlands; UK; Ireland; Spain; Sweden; Switzerland and, notably, France and Germany). A major public misconception appears to be that the phrase «unconventional gas» implies new, untested, and therefore risky, drilling and completion technology (see Section 6).

The reality is that none of this is new. The first hydrocarbon well drilled was a shale gas well drilled around 1825 and shale gas has been produced continuously in the US for the past 185 years. The first attempt to induce fractures in a shale gas well was in 1857, two years before the first oil well was drilled.

Hydraulic Fracturing

The first commercial fracturing treatments were carried out in Oklahoma and Texas in 1949 by Howco. In the first year of operation 332 wells were treated. By 2008 the annual number of frac stages completed worldwide had risen to 50,000 (> 100,000 in 2011).

Hydraulic fracturing of Devonian shale was tested under the Department of Energy-funded Eastern Gas Shales Project, which commenced in 1976. The first attempt to fracture the Barnett Shale (Fort Worth basin, Texas) was made by Mitchell Energy in 1981 but it took until 1998 for the company to develop an appropriate light sand frac using low-viscosity fluid («slick water») that would realize the full potential of the Barnett Shale.

Horizontal Drilling

The first recorded true horizontal oil well was drilled near Texon, Texas in 1929 and sporadic use of the technique was made in the US, China, the U.S.S.R. and else-where but it was not until the early 1980s that the technique began to be used commercially, commencing in France and Italy. By 1990, over 1,000 horizontal wells were drilled worldwide, the great majority in Texas (DOE/EIA 1993). In 2009 the number of horizontal wells drilled in North America exceeded the number of vertical wells for the first time and by 2010, 60% of all wells drilled in the US were horizontal.

The first horizontal well for shale gas was also drilled as part of the Eastern Gas Shales Project. In 1986, the US DOE collaborated with industry to complete an air-drilled 2,000-foot-long horizontal Devonian shale well in the Appalachian Basin. The first attempts to drill commercial horizontal shale gas wells were made in the Barnett Shale in the early 1990s but were uneconomic. When they were reentered from 2001 onwards and fractured, using the later slick water technology, their productivity increased significantly.

In Europe, the issues surrounding unconventional gas, especially shale gas, have now entered the political realm, creating a further condition of uncertainty. Vested commercial interests (e.g. the nuclear industry; the renewable energy industry; importers of conventional gas) may also be a factor. Until there is public recognition that the drilling and fracturing technology that is in use has been applied for decades in hundreds of thousands of wells and that all that is «unconventional» is the mode of subsurface occurrence of the natural gas, there are likely to be deferrals and delays in the evaluation of shale gas potential in a number of countries.

1.2 Coal seam gas

Coal seam gas, also known as coalbed methane (CBM), coalbed gas and natural gas from coal, is a methane-rich gas that occurs in undeveloped coal beds and worked coal seams. It is a self-contained source-reservoir petroleum system in which most (~ 90%) of the gas occurs adsorbed on coal surfaces with the remainder as gas dissolved in formation water or free gas in cleats and micro pores. It is the adsorbed gas that makes these relatively thin coal seam reservoirs an attractive exploration prospect. A coal can store six to seven times as much gas as the equivalent volume of rock in a conventional reservoir.

Commercial accumulations are generally found in relatively shallow coals from 150 m to 1,500–2,000 m. At greater depths the pressure tends to suppress the fractures required for production. Ideally seams should be greater than 0.5 m in thickness and have a well-developed cleat (fracture permeability) system. Coal fracture permeability is low and typically ranges from about 1 milliDarcy (mD) to tens of mD but permeabilities as low as 0.01 mD can be exploitable if other factors are favourable (Composite Energy 2010). Fracture permeability can increase over time by as much as an order of magnitude as gas desorbs and the matrix shrinks. Coals occurring in a present-day extensional regime will normally flow better.

A coal which contains less gas than its adsorption capacity at reservoir temperature and pressure is said to be undersaturated and will produce formation water until the reservoir pressure is below the saturation pressure of the coal. Coals which are gas saturated and produce gas immediately are called «dry» coals. Dewatering during initial pressure reduction and co-production of water during the production phase may give rise to water disposal issues. The most productive coals are sub-bituminous to sub-anthracite with vitrinite reflectance (R_0) ranging from 0.6 to 1.6%.

1.3 Tight gas

Tight gas – also sometimes referred to as «deep gas» and «basin-centred gas» – is not restricted to regionally pervasive resource play accumulations but also occurs in conventional traps. It is therefore not necessarily basin-centred and not necessarily deep.

When tight gas occurs in the basin-centred gas setting, the gas pervades abnormally pressured low-permeability reservoirs in the central (generally deeper) part of basins. It is typically overpressured in subsiding basins and underpressured in uplifted and eroded basins. In basin-centred gas accumulations the up-dip seal may be a gas/water transition zone, causing reduction in relative permeability. In this reversal of normal hydrocarbon occurrence, water overlies gas rather than forming a down dip gas-water contact. The character of basin-centred gas accumulations was first described in detail by Law & Dickinson (1985) and their characteristics have been summarised in the U.S Geological Survey series «Geologic Studies of Basin-Centred Gas Systems» (e.g. Bartberger et al. 2003).

Tight gas reservoirs generally occur in sandstone or siltstone and much more rarely in carbonate rocks. Tight gas accumulations are defined by low permeability and porosity. The average matrix permeability is taken to be less than 0.1 mD or less than 0.6 mD effective permeability to gas, though «ultratight» reservoirs with permeabilities as low as 0.001 mD have been exploited in the Rocky Mountain region in plays such as the Mesaverde Group in Colorado's Piceance Basin and the Elmworth Field in Alberta's Deep Basin.

Maximum porosity can be as great as 15% though 10% porosity is more typical. It is a characteristic of tight gas that large pores are not connected. Instead the pore interconnectivity is limited by micro porosity with pore throats as small as 1 μm (micron) in diameter (Lovell et al. 2010). Reservoirs are generally gas saturated with very little free, movable water but, because of the low permeability, have high irreducible minimum water saturation generally between 30% and 50%.

There are several causes of tight gas reservoirs and these often occur in combination. The original depositional environment of the sediment can contribute to reduced permeability if sand grains occur in a clay matrix. Post-depositional compaction reduces porosity and permeability upon burial.

Cementation of pores can occur (quartz; carbonate; anhydrite) and at temperatures above 120° C (which approximates to a depth/paleodepth greater than 4,000 m) growth of fibrous illite can impede fluid movement through interconnected porosity. Locally, where evaporates are present, salt plugging of the pores can also occur.
The best tight gas reservoirs are heterogeneous with higher poro-perm «sweet spots» that can be of either sedimentological or structural (e.g. flexures) origin. In the US some of the most prolific tight gas plays comprise thick gross pays containing stacked sandstones that can be fractured over the entire interval (e.g. Jonah Field, Wyoming).

1.4 Shale gas

The organic-rich mudrocks that we tend to think of as the source rocks for conventional hydrocarbon accumulations also play host to a variety of less conventional deposits. At shallow depths, when still immature, organic shales may contain biogenic gas accumulations or their organic matter (kerogen) can be converted to synthetic shale oil by thermal methods. At higher temperatures, within the oil window, both liquids and gas are generated, the relative proportions depending on the type of organic matter preserved in the shale and, depending on the expulsion efficiency of the generated hydrocarbons, substantial volumes of hydrocarbon liquids can remain trapped in the shale source rocks. In fractured shale oil plays this trapped oil is recovered through natural or induced fractures.
At still higher temperatures, outside the oil window, thermogenic gas is generated from organic-rich shale through the breakdown of organic material or the thermal cracking of pre-existing hydrocarbon liquids, creating potential shale gas plays.
Good shale gas reservoirs are typically organic-rich (TOC > 2%), thick (> 50 m) and brittle with quartz or carbonate content greater than 40 %. Ideally they should be naturally fractured but the fractures should be contained and not propagate into adjacent porous strata. Both natural and artificial fracturing is therefore enhanced if the shale is limestone bound.
Shale gas contains a mixture of free gas and adsorbed gas and these produce at different rates. Free gas is associated with the shale micro porosity and any fracture porosity, while adsorbed gas is attached to mineral surfaces and concentrated in the organic carbon fraction of the shale. Free gas will produce immediately while adsorbed gas is produced as pressure declines. It is therefore important in shale gas prospect evaluation (a) to have knowledge of the relative amounts of free and adsorbed gas and (b) not to place too much emphasis on initial production rates, which will be heavily influenced by the free gas component.

2. Waste Zones, a source for overlooked hydrocarbons

2.1 The concept of waste zones

Petroleum basins are mostly very wasteful and inefficient systems (Fig. 2, 4). The complex process of hydrocarbon generation in a pod of mature source rock, expulsion, migration, trapping, remigration, uplifts, erosional processes and bacterial degradation offer countless threats to the initial charge. In most cases only a minor fraction of the generated oil and gas accumulates eventually in structural or stratigraphic traps, where it can be produced with the present conventional technology. Large volumes of the initially generated hydrocarbons leak over geological times to surface and are destroyed. Important volumes, probably much larger than the conventionally trapped quantities, remain «stuck» in the system in low permeability tight carbonates and sand-stones (e.g. in the Carboniferous of the North-German Basin) and even in many of the cap rocks (e.g. Ten Boer Formation above the giant Groningen gas field). An even larger fraction of the generated oil and gas has never been expelled from the source rock and has thus remained in situ, partly adsorbed, partly as free gas within the organic rich sediments. Both, the hydrocarbon bearing low permeability rocks, as well as rich source rocks have always been known for conspicuous oil and/or gas shows when being drilled, but standard technology did not allow commercial production. It is these, previously non-producible but hydrocarbon-filled rocks, that we call waste zones. The concept has been discussed already in earlier publications in this bulletin (Burri 2008, Burri 2010).

Waste zones are traditionally all the zones that contain expelled hydrocarbons that cannot be produced due to the low permeability. This includes oil and gas in tight sandstones and carbonates, basin centre gas (gas below water in low perm reservoirs) as well as gas saturations in seals. In this paper we explicitly extend the term waste zone to include all hydrocarbons that are not expelled but still contained in the source rock, be they shale gas or CBM.

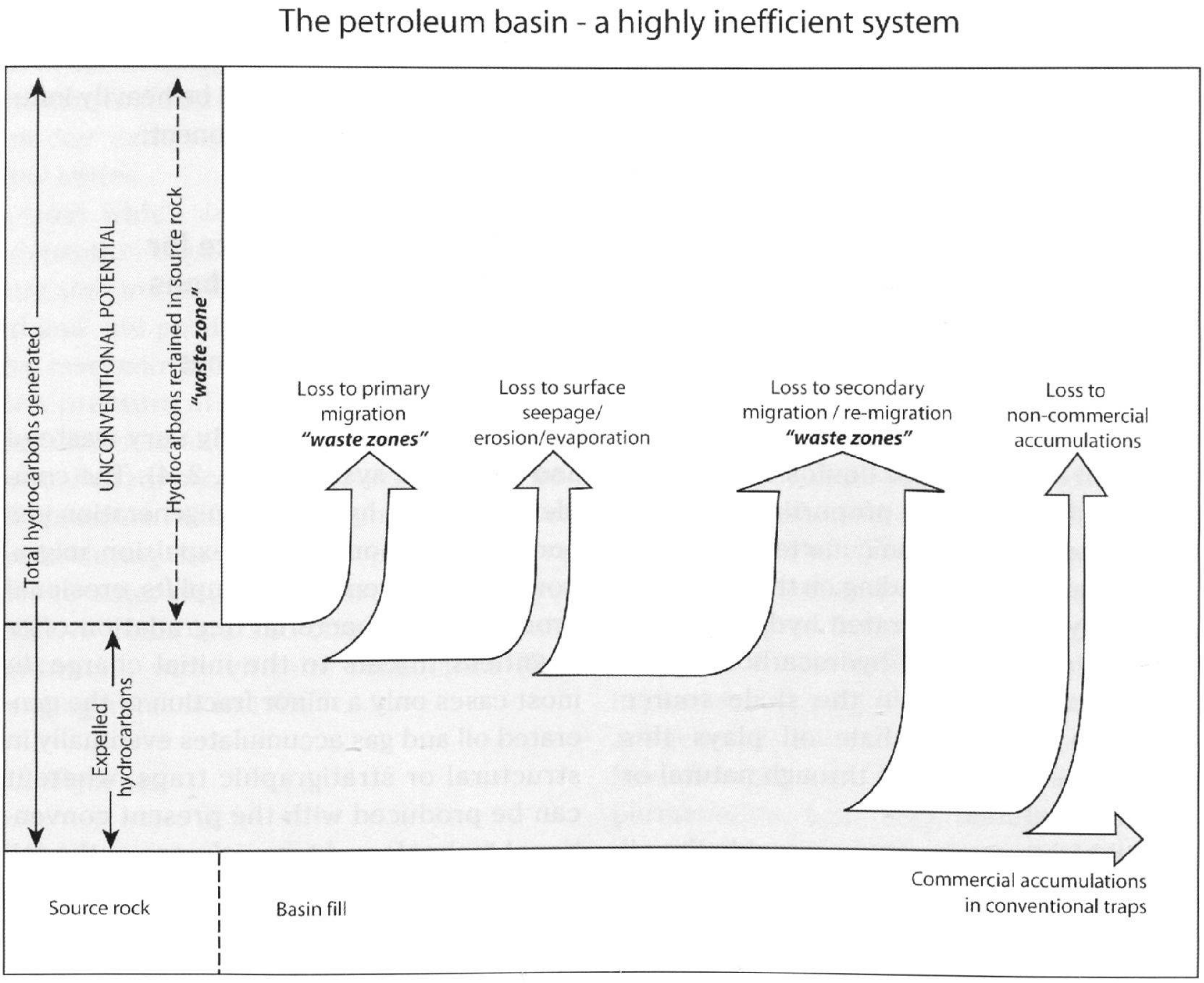

Fig. 2: Efficiency of hydrocarbon systems, the cascade of losses. Although the relative amounts vary from place to place, this figure gives the general concept of the dissipation of generated petroleum and shows that the majority of hydrocarbons are lost or retained in the system. «Hydrocarbons Generated» contained originally only the expelled hydrocarbons; a larger part of the oil and gas generated, remains, however, in the source rock. This significantly increases the discrepancy between volumes generated and volumes trapped. (Figure after England 1994, with major modifications).

2.2 Technology

It is only thanks to step change improvements in horizontal drilling technology, multilateral wells and advanced stimulation by multiple hydraulic fracs that these waste zones have become economically producible during the last decade. Advances in geophysical tools, like high resolution 3D seismic and microseismic monitoring of fracs have added to the success. By being developed into efficient routine operations, precision horizontal drilling and complex multi stimulation became not only doable but affordable - helped also by rising oil prices after 2004 - and could be economically applied to ten thousands of wells. Unconventional gas and oil is a textbook example of how technology cannot only accelerate production of reserves but can add substantial new reserves to the books.

2.3 Generation-Accumulation-Efficiency

The Generation-Accumulation-Efficiency (GAE) looks at the balance of generated and expelled hydrocarbons vs. the hydrocarbons accumulated in traps. The GAE of a petroleum system is difficult to establish; good material balance approximations are only possible in basins with high exploration maturity, where most hydrocarbons have already been discovered. Material balance requires also a very good understanding of the geological features and processes in the basin, like source rock type, quality and volume, maturation history, basin geometry and structural history.

The result of the GAE is highly dependent on the amount of hydrocarbons that are calculated to leave the source rock, i.e. on the expulsion factor. Peters et al. (2006) show that expulsion was often over-estimated; especially the Rock-Eval method appears to have resulted in estimations of unrealistically high volumes of expelled petroleum. Some of the earlier charge calculations may therefore have been exaggerated by up to a factor 2-3. Peters assumes that expulsion for rocks containing < 2% TOC is very low since these rocks may be incapable to establish the continuous bitumen network, required to allow expulsion. Expulsion factors increase with increasing Hydrogen Index of the source rock, implying that expulsion efficiency from oil prone source rocks is higher (by a factor 4 - 5) than the expulsion efficiency from gas prone source rocks (Fig. 3).

The GAE has been discussed extensively by Magoon and Dow in their AAPG Memoir 60 (Magoon & Dow 1994). This Overview of Petroleum Systems (Magoon & Valin 1994) is still the most comprehensive compilation and analysis of the efficiency of petroleum systems. Fig. 4 compiles the GAE calculated for various petroleum systems of the world by Magoon & Valin and a number of values of GAE from other sources. Since GAE calculations can only be done in very well understood, mature basins with low complexity, many of the world's main hydrocarbon basins are still missing.

The probably most elaborate evaluation of a petroleum system and its efficiency has been carried out for the highly efficient New Albany-Chesterian petroleum system of the Illinois Basin (Lewan et al. 2002). Of the total charge of 78 billion bbls of oil expelled, a full 74% have escaped to surface and were eroded, 12% are considered residual migration loss (i.e. these hydrocarbons are still stuck in the system as non producible oil in tight rock) and a high 14% have accumulated in traps. Most of the evaluated petroleum systems show efficiency ranges far below the New Albany, reaching, according to the paper of Magoon & Valin, from a GAE of 36% (in the very small and confined Heath-Tyler petroleum system in central Montana) to 0.3% (Point Pleasant-Brassfield in the Apalachian Basin); the majority of the basins have values far below 10%.

It is sometimes argued that, if more oil has leaked out of the system than was trapped (e.g. the destruction of 58 billion bbls in the New Albany, mentioned above) this should

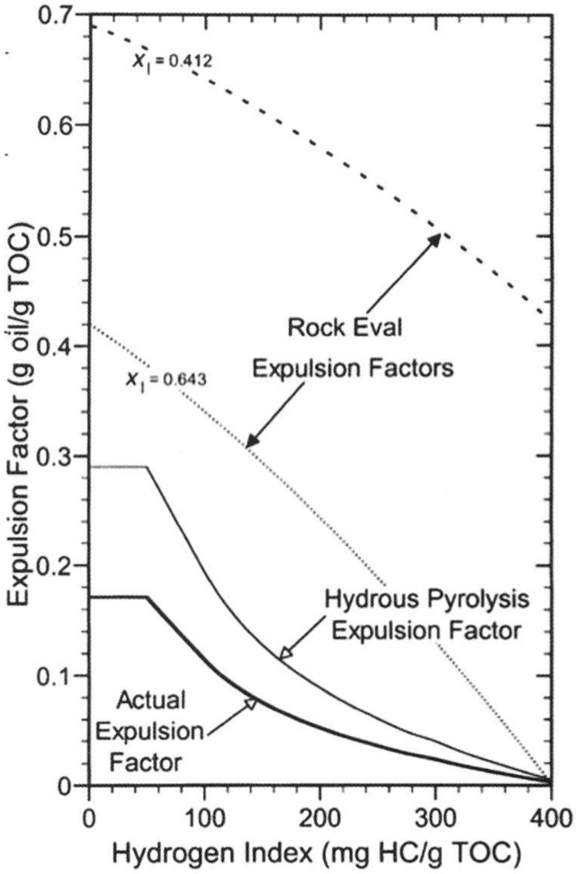

Fig. 3: Expulsion factors as a function of evaluation method. Note thermal maturity increases from right to left as indicated by the decreasing Hydrogen Index. Calculated expulsion factors using Rock-Eval pyrolysis (used predominantly in older assessments) give an expulsion efficiency about twice as high as values derived from hydrous pyrolysis which more closely represents the processes actually taking place in the source rock. M. Lewan argues that even the hydrous pyrolysis results may overestimate the expulsion by a factor two. Very similar results have been obtained by K. Peters et al. (2006) in the Alaskan North Slope. The fact that expulsion factors are low in absolute terms (at best between 0.2 and 0.3 g oil / g TOC, higher for gas) and much lower than previously assumed, implies that the majority of the generated hydrocarbons are likely to remain in the source rock, creating a large potential for shale gas and shale oil production. (Lewan et al. 2002, AAPG ©2002, reprinted by permission of the AAPG whose permission is required for further use).

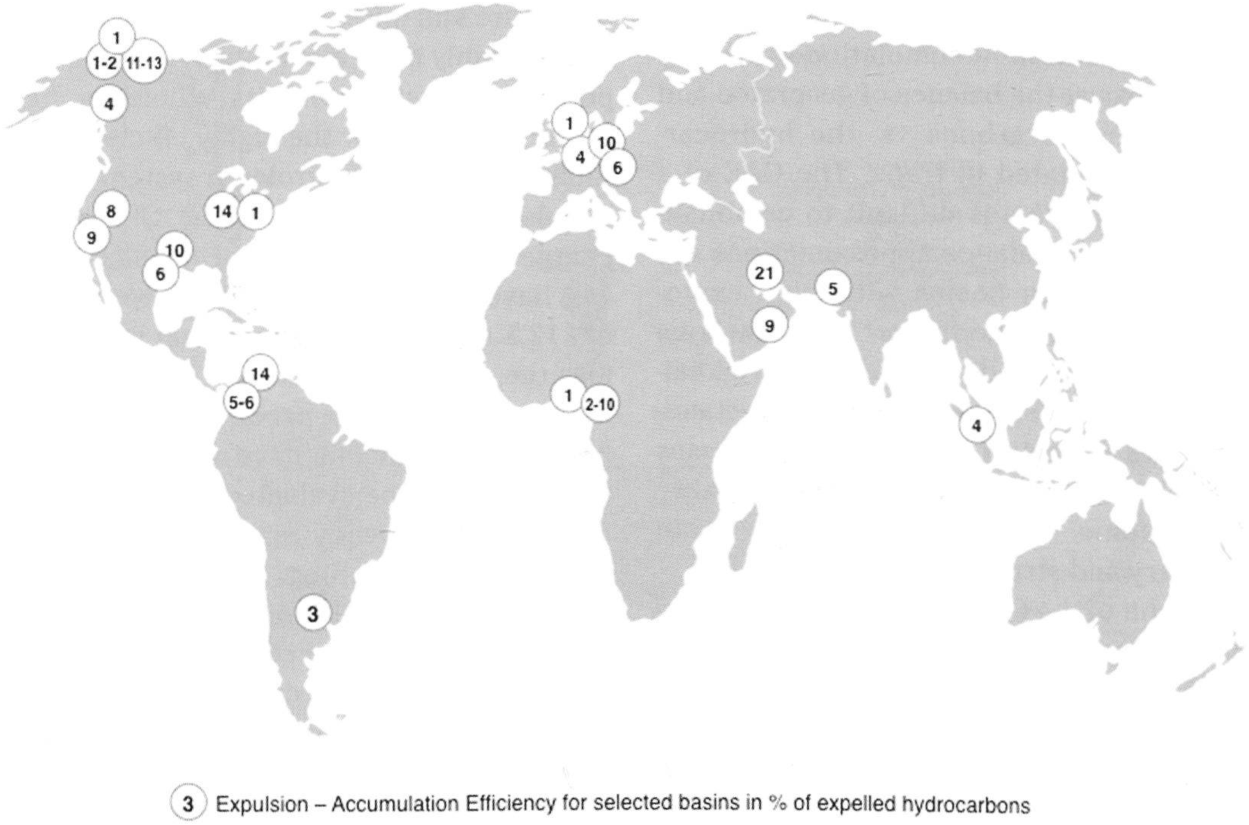

Fig. 4: Worldwide Hydrocarbon Generation-Accumulation Efficiency of petroleum basins. Generation-Accumulation-Efficiency (GAE) is generally below 10%, illustrating the very poor efficiency of most petroleum basins. Note that most ratios use expelled hydrocarbons and not the total volumes generated in the source rock. This map is based on the publications by Magoon & Valin1994; Lewan et al. 2002; Legarreta et al. 2004; Terken 1999; Tuttle 1999; Masterson 2001 and various contributions by H. Doust and E. Dolivo.

leave conspicuous traces in the geological record. However, in geological times thousands of billions of bbls can probably leak into the sea, can evaporate, be eroded, oxidized and removed without much of a trace. Surface leakage of only 1 MMbbls/year adds up to a staggering 1 Trillion bbls in 1 MM years (a timespan insignificant in geological terms). Total natural seepages today in oceans alone are estimated at 4.4 MMbbls/year (National Academy of Sciences, 2002) and, given the fact that the total surface of sedimentary basins on land is larger than in the offshore, annual natural surface leakage of oil probably exceeds 10 MMbbl.

The influence of individual parameters controlling GAE cannot be quantified at present. It might be expected that old plays with early maturation and a long further geological history would be more prone to leaking over geological times and would thus have a low efficiency, but this is not borne out by the data. Efficiency rates show no correlation with age of source rock and time since maturation. The Illinois Basin with a Devonian-Mississippian Play has a very high GAE of 14%, while the much younger world-class upper Jurassic source rock of the Mandal-Ekofisk play in the Central Graben of the North Sea has a very low GEA below 1%. GAE appears largely to be a function of the proximity of key elements (source rock, reservoir, trap) and the complexity of the tectonical history with respect to the time of generation. The Persian Gulf-Saudi-region owes its richness in hydrocarbons to the fact that the petroleum system is very simple with world class source rocks, reservoirs and seals in close proximity to each other and with minimum tectonic disturbance after the emplacement of hydrocarbons. This allows in some petroleum systems for a uniquely high trapping efficiency of over 20%.

2.4 Expulsion efficiency

The observation by Lewan et al. (2002) and Peters et al. (2006), that the expulsion efficiency of source rocks (i.e. the fraction of HC leaving the source rock) has probably been overestimated in the past, may lead to a certain correction of the very low trapping-expulsion rations derived by Magoon et al. (1994), but this does not change the fact that we are generally dealing with very wasteful systems (Fig. 2). Peters states that «Regardless of the method employed, all calculations of the volumes of expelled oil from each source far exceed estimates of trapped in-place oil».

Lower expulsion efficiency reduces the amount of hydrocarbons migrating into the system but it increases the amount still contained within a mature source rock. Expulsion efficiency is a factor of maturation, but even more importantly of the type of organic matter that forms the source rock (Peters et al. 2006). Gas-prone land plant source rocks of Type III expel some 5 - 10% of the generated hydrocarbons. Oil-prone algal or structureless organic matter source rocks of Type I and II oil expel only some 20 - 35% of the generated oil and gas. Type I and II source rocks will, in the mature and overmature state, also produce large amounts of gas; the majority of the US shale gas plays exploit in fact mature oil source rocks. Due to the overall low expulsion efficiency most hydrocarbons never leave the source rock where they have been generated. Comparing not only the expelled hydrocarbons (as previously done) but the total originally generated hydrocarbons with the trapped volumes will thus result in an even lower overall trapping efficiency for conventional plays than displayed in Fig. 4.

2.5 The source rock-reservoir-seal system of shale gas

The source rocks of the conventional plays are the reservoirs of the shale-gas plays. Shale gas producing horizons are source, reservoir and seal in one. Many producing shale gas reservoirs are overmature, oil-

prone source rocks, containing Type I and mainly Type II kerogen. Maturity for gas producing source rocks reaches from VR > 1 to 3. Effective porosity for shale gas production is strictly linked to the amount of organic matter: Interclay porosity is filled with water; organic porosity is filled with gas.
The porosity of source rocks has previously been underestimated. Kerogen occupies in fact a much larger volume percent of the rock than is indicated by the TOC weight percentage due to the low grain density of organic matter. Microporosity can therefore be very high, reaching 50% of organic matter (Fig. 5). As a portion of the total rock volume this organic porosity can reach over 20%.

2.6 Implications

Considering that in most cases only a few percent of the hydrocarbon charge makes it into conventional traps, the volumes of hydrocarbons still retained in the source rock are likely to be an order of magnitude larger than all the eventually trapped accumulations. Even if we have to assume low recovery factors from source rocks – some 30% for gas, much lower for oil – the implication is that theoretically the unconventional resources could amount to a multiple of the known conventional volumes. Whether these volumes are economically recoverable will be determined by the development of energy prices and by the technical progress.
In summary: It is the waste zones, i.e. the inefficiency of the petroleum systems that provides us with the opportunity of the unconventional plays. The «lost hydrocarbons» will be the main targets of the future exploration.

3. European Activities

Europe is a prime target for the development of unconventional natural gas. It has a large population and therefore large market. The proximity to market and the presence of an established pipeline infrastructure improves the economics of the low per-well production volumes that are characteristic of much unconventional natural gas production. There is an increasing demand for natural gas and Europe has shown historically strong natural gas prices and market fundamentals. Development of indigenous sources would help reduce dependence on imported gas.
However, a recent study by the Oxford Institute for Energy Studies (Gény 2010) argues

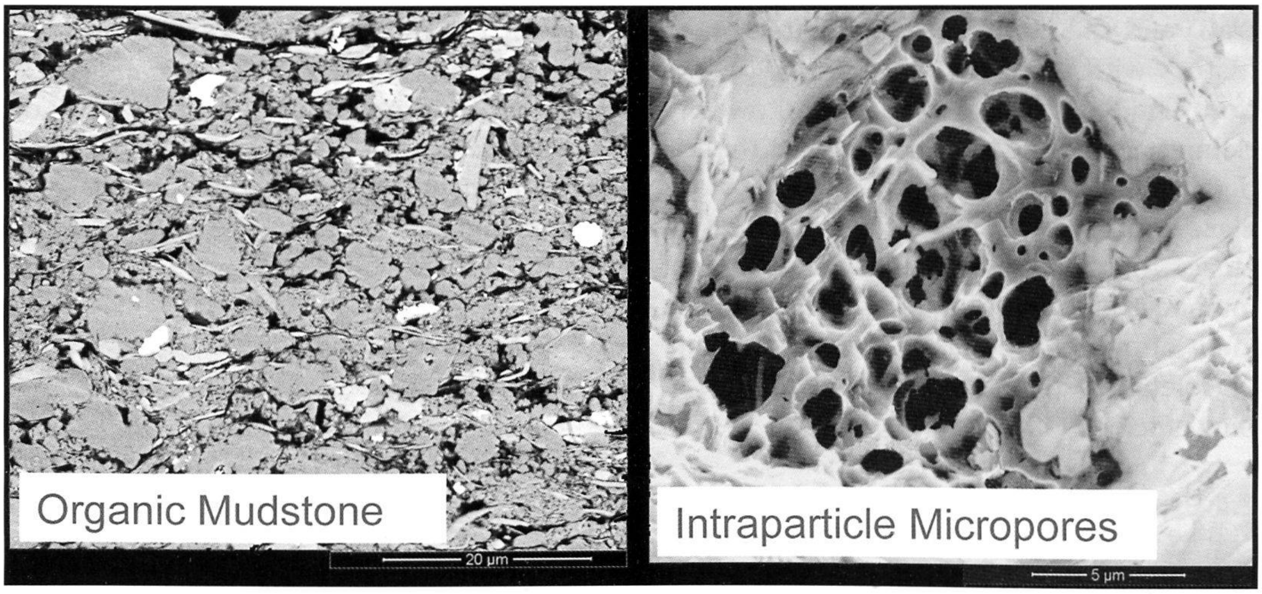

Fig. 5: Porosity types in gas shales (Corelab, Shell Unconventional Group, Courtesy J. Yu Jie).

that due to more stringent European environmental standards (as compared to those in the US), difficulties of access to land and fresh water and lack of incentives for landowners to allow companies to drill, a different business model is required. The author suggests that the development of unconventional gas will not be a game changer for European gas markets overall as it has been in the US, but it certainly could have a significant impact in individual countries, especially Poland and Germany. Overall it would be surprising if unconventional gas provided more than 5% of European gas demand before the early 2020s.
The current competitive European landscape is fragmented in terms of players of all sizes (majors to independents, as well as NOCs). Poland will act as a stress test for future development trends of unconventional gas. Fig. 6 shows the European competitive landscape in early 2011.

3.1 Coal seam gas

European in-place coal seam gas resources probably amount to about 300 Tcf (Table 1), but recoveries are expected to be low.
Unlike the prolific coal seam gas basins of the western USA and Canada, in which the productive formations are largely Upper Cretaceous to Palaeogene, the European basins are mainly of Westphalian age, akin to the Pennsylvanian-age coal basins of eastern and central USA which were deposited in a similar depositional environment, within 10° of the Late Carboniferous equator.

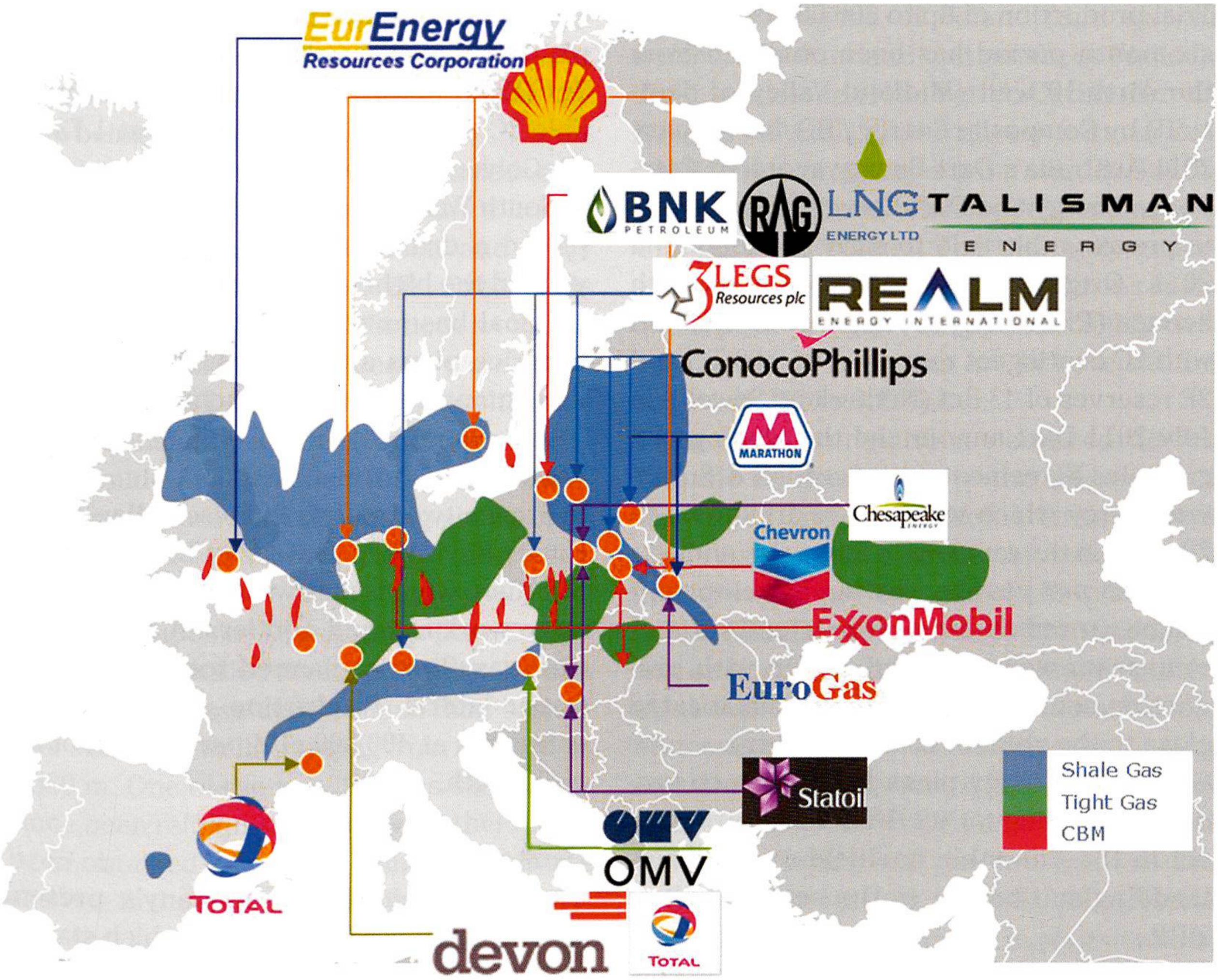

Fig. 6: European unconventional gas activities.

Country	Coal Seam Gas In Place (Tcf)	Ultimate Recoverable (Tcf)	2009 Production (million cu ft / day)
Germany	100		
United Kingdom	100		0.045
Netherlands	35 – 70	9 – 22	
Poland	15 – 50		
Czech Republic	2 – 13		
Hungary	5.5		
Belgium (Limburg)		0.25	
Bulgaria	3		

Tab. 1: Published European coal seam gas resources by country.

Since the mid 1990s coal seam gas prospects have been evaluated in at least 12 European countries but production is limited to the United Kingdom. The following review is limited to the four countries in which recent drilling activity has taken place.

United Kingdom

Trial production of up to 200,000 cf/d over a six-month period has been obtained from the Airth-10 well (Midland Valley of Scotland) by Composite Energy / BG. In February 2011 Australia's Dart Energy acquired Composite Energy and Dart Energy Europe plans to progress this field to early production in 2011. Original gas in-place in the Airth licence (PEDL 133) is reported as 1.09 Tcf with 2C contingent resources of 0.60 Tcf and 2P reserves of 43 Bcf (Netherland Sewell). In July 2011 Dart announced the signing of a gas sales agreement with Scottish & Southern Energy which will require drilling up to 20 wells in the ramp-up to first sales and 10 – 12 wells per year thereafter. Development will be carried out from multi-lateral surface-to-in-seam wells inclined up-dip with production coming from vertical wells located close to the point of coal seam entry.

Greenpark Energy plans to commence production drilling for its Broadmeadows project in the Canonbie coalfield on the Scotland-England border in the second half of 2012.

At Doe Green (Lancashire Coalfield, England) IGas Energy has had commercial production (currently 60,000 cf/d) from one well since June 2009 and spudded a second production well in July 2011. The Potteries project at Keele in Staffordshire has development approval but although the first well produced some gas on dewatering, mechanical problems limited the productive section of coal and a workover is being engineered. Total Gas mid-range unrisked gas initially in-place in the UK has been estimated as 9.10 Tcf (Equipoise) while contingent recoverable 2C resources are estimated at 1.73 Tcf (DeGolyer & McNaughton).

In South Wales, Composite Energy / BG completed a drilling campaign in 2010 which yielded the highest gas contents of all of the UK coal basins that they have tested and Centrica plans an exploration and evaluation campaign there, commencing in 2011.

France

In France two laterals in Folschviller-2 (Lorraine) have been tested by European Gas but there were issues with water influx from mine workings and aquifers. A demonstration gas flow is planned for 2011 on the upper lateral. Production performance is estimated at 400,000 cf/d per 1,000 m of lateral length.

Germany

The vast majority of Germany's present methane-rich gas E&P activity, which started in the early nineties of the last century, is focussed nowadays on abandoned coalmines

in the German Ruhr area. This region includes Germany's largest share of proven Upper Carboniferous coals. Their gas content varies between 0 and > 20 m^3 CH_4/t coal with an average of 5 - 10 m^3/t (Juch, Gaschnitz & Thielemann 2004), resulting in estimated 70 Tcf of gas in place related to coal seams (Littke et al. 2011).
A first exploration well was drilled in the 1930s by a Belgian company (Vingerhoets, TD 2,363 m). During the 1960s, the scientific well Münsterland 1 was drilled particularly with regard to the potential occurrence of hydrocarbons, reaching a total depth of nearly 6 km (Geologischer Dienst NRW, 2011).
In 1995 a consortium of Ruhrgas AG and ConocoPhillips Inc drilled two deep coal seam gas exploration wells (Rieth-1: 1,736 m; Natarp-1: 1,995 m) in Münsterland, Germany. Natarp-1 was fracture tested. However, due to unfavourable economics and rather low flow rates, the consortium decided to put any further G&G activities on hold for the time being.
In Q3 2010 ExxonMobil commenced coal seam gas exploration in Germany's Lower Saxony and Münsterland basins and in Q4 2010 / Q1 2011 drilled two wells, Osnabrück-Holte Z2 and Bad Laer Z2. In both wells the Upper Carboniferous coal seams were cored for further G&G studies, but no results have been published yet. Three additional wells (Nordwalde Z1, Borkenwirthe Z1 and Drensteinfurt Z1) are currently being planned.

Poland

In 2010 Composite Energy (now Dart Energy Europe) / BG drilled three wells in the Lublin Coal Basin. These were deeper than typical coal seam gas wells, ranging from 1,370 m to 1,880 m. One of the two licences drilled has since been relinquished but two others have been obtained, one in the Lublin Coal Basin and one in the Upper Silesia Coal Basin. Original gas in-place in the three Dart Energy licences has been estimated at 4.8 Tcf (Netherland Sewell).

In contrast with the extremely limited extent of coal seam gas development in the region, Europe, especially Germany (over 50 projects) and the United Kingdom (29 abandoned mine methane [AMM] vent approvals and 19 methane drainage licences for safety in active coal mines), is a world leader in Coal Mine Methane (CMM) production. Following the introduction of the German law on renewable energy in 2000, the electricity generated by AMM/CMM projects grew almost sevenfold from 2001 through 2007. Czech Republic, France, Poland, Kazakhstan, Romania, Russia, Slovakia and Ukraine also have CMM projects.

3.2 Tight gas

Tight gas-filled deposits occur in Permo-Carboniferous sandstones eastwards from the Lough Allen Basin (Carboniferous) in Ireland to the Rotliegend of Poland (and also in northern Switzerland and northern France). Tight sandstone of the Permo-Carboniferous Southern Permian / Northwest German-Polish Basin is productive from the UK Southern North Sea and offshore Netherlands to Germany and Poland. The thermally generated gas is derived from Carboniferous coals and type III kerogen (Gaupp et al. 2008). German in-place resources are believed to be largest at 350 to 600 Tcf.
Tight gas accumulations also occur in the Triassic Buntsandstein of the UK Southern North Sea and in the Netherlands, where they represent 30% of the estimated Dutch in-place tight gas resource of 175 to 280 Tcf. Lower Miocene (Karpatian) tight sandstone has been drilled in the Kiskunhalas Trough, a sub-basin of the Pannonian Basin. Middle Miocene tight gas sandstones are being investigated in sub-basins of the Pannonian Basin in eastern Croatia and Slovenia and western Hungary and also in the Derecske sub-basin in eastern Hungary. A possible Upper Miocene basin-centred gas accumulation has been tested in southeast Hungary's Makó Trough (Pannonian Basin) but without

significant success or proof of the concept. The Makó Trough occurrence is the only reported instance of a basin-centred accumulation in Europe (although the Bekes Trough on the eastern margin of the Makó Trough may also have basin-centred potential). All other reported European tight gas reservoirs are thought to occur in conventional traps.

The only productive tight gas carbonate reservoirs in Europe are in Upper Jurassic – Lower Cretaceous carbonate in the Aquitaine Basin, France.

Tight gas development

Since the 1990s, production of European tight gas reservoirs has been transformed by the use of multi-fractured horizontal wells (MFHW). They have been particularly successful partly because they are more cost effective from offshore platforms and also because they are being used to develop single relatively thin intervals.

Germany

In 1995, Söhlingen Z-10, drilled by Mobil (now ExxonMobil) in the Lüneburg region of Niedersachsen (Lower Saxony), produced at a stable rate of 18 million cf/d from a 630 m horizontal section at a depth of 4,780 m (142° C; 8,700 psi) in a Lower Permian Rotliegend sandstone reservoir with permeability of 0.01 – 0.02 mD and porosity of 10 – 12%. After developing Söhlingen in the period through 2000, ExxonMobil conducted further fracturing in the period 2006 – 2010 at both at Söhlingen and to the west in the Südoldenburg and Carboniferous field areas in the Weser-Ems region, Niedersachsen. GDF / Wintershall also successfully tested a MFHW at Leer (well Leer Z4) in Ostfriesland, Niedersachsen, in 2005. Leer Z4 reached the defined target in the Rotliegend formation at 4,424 m TD with a horizontal section of about 2.5 km and was successfully multi-fractured.

Hungary

In September 2009, Austria's RAG (Rohöl-Aufsuchungs Aktiengesellschaft) acquired Toreador Hungary Ltd. Toreador had just drilled the Balotaszallas E-1 (Ba-E-1) well in the Kiskunhalas Trough of the Pannonian Basin. Ba-E-1 encountered an over-pressured 1,840 ft gross gas-bearing interval in an interbedded Karpatian (Lower Miocene) sequence of siltstone, shale and sandstone below 10,000 ft. The two lowest zones were fractured and are believed to have produced gas-condensate. In July 2011, Delta Hydrocarbons/RAG/Cuadrilla recompleted an additional three zones of the Lower Miocene reservoir in what is assumed to be tight sandstone. Testing produced satisfactory gas flow rates plus a small amount of condensate. An extended production test into a sales pipeline is expected to commence in August 2011 and full gas-condensate production should commence before end-2011. Cuadrilla has the option to earn a further interest by drilling and completing a second well in the Ba-IX Mining Block. MOL's activity has focused on Middle Miocene tight sandstone in the Derecske Basin where there has been limited but continuous gas production since the 2006 Berettyóújfalu-1 well was brought on stream in 2008. Two Beru wells were drilled in 2010 and should be tested in Q3 2011. Four wells are planned to be drilled and tested in 2012/13.

Poland

Aurelian completed the fracture stimulation process for the first MFHW (Trzek-2; 10 frac stages) in the Polish Rotliegend in February 2011 as part of its Siekierki Project in the North Poznan concession. A sidetrack is planned for Q4 2011 to increase production from the current 3 million cf/d. A second horizontal well was fracced (Trzek-3; 6 stages) in July / August 2011 and should be flow tested by end August. In the Fences concession, on the same Rotliegend tight gas trend, Polish state company PGNiG and FX Energy are testing the Plawce-2 vertical tight gas well prior to deciding on completion options (unstimulated vertical; vertical frac; drill an unstimulated horizontal leg). The in-place tight gas resource for the entire area is estimated at over 2 Tcf.

Slovenia
Ascent Resources plans to fracture the tight Middle Miocene (Badenian) reservoir in two redevelopment wells in the Petisovci field in Q3 / Q4 2011.

3.3 Shale gas

Europe is particularly well-suited to gas resource play exploitation on account of its large market, established pipeline infrastructure, increasing demand and current de-pendence on gas imports. Relatively high natural gas prices add to the attraction.
Shale gas exploration in Europe is in its infancy. The first exploratory well was spudded in Germany in 2008 and since then exploratory drilling has been limited to four countries. As a consequence, little is known about Europe's ultimate potential.
Rogner's 1996 estimate of the in-place shale gas resource of Europe (including Turkey) was 550 Tcf. More recent studies indicate significantly larger in-place resources. In their assessment of the world's shale gas resource, the US Energy Information Administration (EIA) estimated the European shale gas in-place resource for 10 countries (excluding Ukraine) at 2,390 Tcf with a combined technically recoverable resource of 582 Tcf (US EIA, 2011a). OMV has suggested a potential recoverable shale gas resource of 15 Tcf in the Vienna Basin, Austria, from an in-place resource of 200 – 300 Tcf. TNO's «best estimate» for «producible gas in place» in «high potential» areas of the Netherlands is 198 Tcf from an estimated in-place resource of 3,950 Tcf.
Given the potential size of the in-place resource it is not surprising that investigations are currently under way in at least fifteen countries. Company interest extends from super-majors, such as ExxonMobil and Shell, through majors (Chevron; ConocoPhillips; Eni; Total) and major independents (e.g. Marathon; Talisman) to small niche players (e.g. BNK, 3Legs Resources, San Leon Schuepbach Energy) and coal seam gas explorers who may have some shale gas potential on their acreage (e.g. Dart Europe).
There are three potentially major regional shale gas plays in Europe plus a number of others with local potential.

3.3.1 Lower Paleozoic

The oldest is a Lower Paleozoic play that occurs in northwest Europe running from eastern Denmark through southern Sweden to north and east Poland. The organic-rich shales with shale gas potential lie on the south western margin of the Baltica paleocontinent and tend to thicken towards the bounding Trans-European Suture Zone.
In Denmark and Sweden the principal target is the kerogenous Alum Shale of Middle Cambrian to Early Ordovician (Tremadoc) age.

Denmark
Licences have been applied for / awarded over the Fennoscandian Border Zone and Norwegian-Danish Basin onshore Denmark.

Sweden
On 28th November 2009 Shell spudded the first well in a shallow three-well test program in Sweden's Colonussänkan permit (Fennoscandian Border Zone, southern Sweden). Lövestad A3-1, Oderup C4-1 and Hedeberga B2-1 ranged in depth from 749 m to 955 m. In May 2011, Shell announced that its investigations had been completed, that the rock samples from the three wells found only very limited gas traces which are not producible, and that the licences would not be renewed when they expire at end-May 2011 (Svenska Shell 2011).
Four companies have taken out 24 conces-

sions in Östergötland (19) and on the island of Öland (5) in south central Sweden. In this area the Alum Shale occurs at depths down to 150 m and is thermally immature. Nevertheless, gas flows are known from water wells and seeps in the area and flow rates of up to 40,000 cf/d have been reported from wells. Local farmers use the gas as a heating source and the Linköping commune has a processing concession valid until 2033. The prospects are therefore considered to be an analogue of the biogenic-sourced shale gas of the Antrim Shale in the US Michigan Basin. In October 2011 Aura Energy, an Australian uranium exploration company announced that it has commenced drilling at its Motala shale gas project on the east shore of Lake Vättern.

Poland

Further to the southeast, in Poland, the main Lower Palaeozoic target is Silurian-age graptolitic shale, with the Upper Cambrian to Upper Ordovician a secondary target. The Silurian in particular thickens towards the southwest in the area of the Gdansk Depression (Baltic Depression) and the Danish-Polish Marginal Trough, which defines the southwest margin of the Baltic Depression. In parts of the Trough, such as the Warsaw Trough and Lublin Trough, more than 3,000 m of Silurian section may be present.

To date, this play has been the most sought after in Europe. Some 27 concessions have been awarded in the Gdansk Depression, another 28 in the Danish-Polish Marginal Trough and 12 on the East European Platform Margin, northeast of the Marginal Trough. Seven offshore concessions in the Baltic Sea are also considered to have shale gas potential.

Eleven different companies or consortia are active in the Gdansk Depression, including a number of small niche players, but of the 40 concessions on the Platform Margin and Marginal Trough, 20 are operated by one of ExxonMobil, Chevron or Marathon and a further 16 by PGNiG, the Polish state company, or PKN Orlen, another Polish company.

The first tests of the Polish Lower Paleozoic are now under way. Between June and October 2010, Lane Energy (a subsidiary of 3Legs Resources) drilled two vertical wells in the Gdansk Depression, Lebien LE-1 (Lebork concession) and Legowo LE-1 (Cedry Wielkie concession). A 1,000 m horizontal leg drilled in the Lebien well in May was the first horizontal shale gas well drilled in Poland and will be subject to a multistage frac test in Q3 2011. Lane spudded a third well, Warblino LE-1H in July 2011. This well will also have a horizontal leg after the vertical pilot hole is drilled. All wells drilled to date encountered gas in the Lower Silurian and Upper Ordovician. Lane's initial seismic and drilling program on its six Gdansk Depression concessions is being funded by ConocoPhillips, giving the latter the option to earn up to 70% interest in the concessions.

The drilling contractor, NAFTA Pila, which drilled the first two Lane wells spudded Wytowno S-1 (Slawno concession, Gdansk Depression) in December 2010 on behalf of Saponis (BNK; RAG; Sorgenia: LNG Energy). The US$ 6 million well reached TD at 3,580 m in mid-February 2011. The well encountered gas shows in a shallower 40 m Lower Silurian section and over a 91 m deeper Lower Silurian hot shale section. The well appears to have been drilled on a localised palaeo-topographic high, which accounts for the absence of a Cambro-Ordovician section. The strongest shows were recorded in the deeper Lower Silurian interval (124 scf/ton), while the shallower interval averaged 77 scf/ton. Wytowno S-1 was followed by a 3,590 m well, Lebork S-1, on the Slupsk concession, which encountered gas, shows over a 285 m interval from Lower Silurian to Cambrian Alum Shale. The Lower Silurian averaged gas contents of 40 scf/ton while the 155 ft Cambro-Ordovician interval averaged 268 scf/ton. Saponis spudded a third well, Starogard S-1, in July 2011. Fracture testing of the first two wells is scheduled to commence in mid-September 2011 and may include Starogard S-1 in addition.

A promising gas flow was also reported by PGNiG from its Lubocino-1 well on the Wejherowo concession, completed in March 2011.
San Leon / Talisman plan a three vertical well program in the Gdansk Depression commencing in September 2011. Eni also has a 6-well programme planned for its Gdansk Depression acreage, starting in 2011.
The first wells in the Podlasie Depression of the East European Platform Margin, Krupe-1 and Siennica-1, have been drilled by ExxonMobil. The wells appear to have been successful, as the president of XTO, ExxonMobil's unconventional hydrocarbons unit, has indicated that they will be fracture tested in 2011. The farm-out to Total of 49% of the ExxonMobil interest in two concessions in the Lublin Trough and Podlasie Depression, southeast Poland, was approved in July 2011. The company is still seeking to farm-out up to 49% of four other concessions in the Podlasie Depression, east of Warsaw.
The first wells in the Danish-Polish marginal Trough (Lublin Trough) should be drilled in 2011 by PKN Orlen and Chevron (Q4 2011). Marathon also plans to drill at least one well in Q4 2011 though it has not indicated which area it will test.

3.3.2 Carboniferous

The second major play is a Carboniferous basinal marine shale play that extends eastwards from western Ireland and includes the East Irish Sea / Cheshire Basin in northwest England, the Anglo-Dutch Basin, the Northwest German Basin and the Fore-Sudetic Monocline (Northeast German-Polish Basin) in southwest Poland. The gas shales of the Lower Carboniferous (and Upper Devonian) of the Central European Basin system were deposited under consistently marine conditions and have partly high Total Organic Carbon (TOC) contents. Virtually all of these rocks are in the gas generation stage. (Littke & Kroos 2009). The age of the most prospective shales appears to young westwards from the Visean (Middle Mississippian) Kulm facies of southwest Poland and northeast Germany to the Namurian (Upper Mississippian to Lower Pennsylvanian) of northwest Germany, the Epen Formation of the Netherlands, the Bowland Shale in northwest England and the Clare Shale in western Ireland. Visean (Middle Mississippian) shale may also be prospective in Scotland and northwest Ireland.

Poland
Lane Energy, the 3Legs Resources subsidiary, has interests in the Fore-Sudetic Monocline in southwest Poland but unlike the Gdansk area, this activity is not funded by ConocoPhillips. San Leon has also acquired some concessions covering this play, as have PKN Orlen, Silurian Energy Services, and Strzelecki Energia (Hutton Energy). It is not clear, however, whether all of these concessions have been obtained for their shale gas prospectivity. On behalf of the Polish state company, PGNiG, Halliburton frac tested an Upper Carboniferous shale in Markowola-1 in the Lublin Trough in July 2010 but the flow rates are said to have been lower than expected.

Germany
Hartwig et al. (2010) investigated the shale gas potential of both Lower and Upper Carboniferous sediments in western Pomerania in NE Germany from five wells which were drilled during the 1960s and 1980s (Dranske 1/68, Gingst 1/73, and Rügen 2/67, Gingst 1/73 and Pudagla 1h/86). The Carboniferous strata appear in depths between 1 km (Upper Carboniferous) and 4 km (Lower Carboniferous). As a result, those wells have experienced different burial and thermal histories. The results showed, however, that the shale gas potential is generally limited by the rather low TOC content (average < 1.0 wt%), though this may be compensated by great formation thickness.
The nature of German E&P reporting is such, however, that it is difficult to establish the

activity taking place on long-held licences. It is assumed that ExxonMobil, both directly and indirectly through the BEB ExxonMobil/Shell joint venture, will be examining the potential of Visean (Middle Mississippian) shale in eastern Germany and Namurian (Upper Mississippian to Lower Pennsylvanian) shale in the west. Some at least of BNK Petroleum's six concessions are also targeting Carboniferous shale gas.

Netherlands

Cuadrilla Resources has been awarded a license (Noord Brabant) on the margin of the London-Brabant High and West Netherlands Sub-basin of the Anglo-Dutch Basin. It is assumed that the Namurian (Upper Mississippian to Lower Pennsylvanian) Geverik Member of the Epen Formation shale is one of the targets in this location. Two wells, at Boxtel and Haaren, are planned. Drilling of the first well is now planned for 2012 as a result of additional drilling planned on Cuadrilla's UK Bowland Shale acreage (below). It is also possible that one of these wells may be targeting shale oil in the Lower Jurassic Aalburg and Posidonia formations in the Roer Valley Graben while another also targets tight gas in the Triassic. Cuadrilla's other Netherlands licence (Noordoostpolder) in the Northwest German Basin is a Namurian gas shale play.

United Kingdom

Cuadrilla Resources, through its Bowland Resources subsidiary, also has interests in the onshore portion of the East Irish Sea Basin in PEDL 165 in Lancashire, northwest England. Spudded in August 2010, the company's Preese Hall-1 well targeted the Namurian (Upper Mississippian to Lower Pennsylvanian) Bowland Shale. Drilled to a depth of 9,100 ft, the vertical well encountered over 4,000 ft of shale containing both vertical and horizontal fractures and which produced «substantial gas flows». The well was due to have a 12 frac-stage completion over an interval from 5,260 ft to 9,000 ft but after 5 fracs, fracing was suspended due to two small earthquakes in the vicinity of the well (2.3 and 1.5 Richter Local Magnitude). The company has commissioned a study to determine the relationship, if any, between the fluid injection and seismicity. The first three fracs (8,420 – 9,000 ft) were tested on comingled flow and produced satisfactory amounts of gas and frac flow-back water. Fracs 4 and 5 (7,810 – 8,270 ft) were being flowed in mid August 2011. The rig drilled a second well at Grange Hill-1 (TD: 10,750 ft). Preliminary core analyses suggest similar gas contents to Preese Hall-1 but over a thicker series of possible pay zones. The rig then moved to the third well in the area, Becconsall-1, which spudded on 16th August 2011. Preese Hall-l was the first known test of the Carboniferous shale gas play in Europe.
On 22nd September 2011, Cuadrilla Resources announced a preliminary gas in place estimate of 200 Tcf for its 1,200 km^2 PEDL 165 licence in Lancashire. The uncertified estimate is based on the two wells drilled to date by Cuadrilla plus historical data from three wells drilled between 1987 and 1990 by British Gas.
The Bowland Shale may also be prospective east of the Pennine High in the East Midlands sub-basin, where it is a known source rock for oil and gas. Before end-September 2013 eCorp is scheduled to drill one vertical well in the Gainsborough Trough area to a depth of 4,500 m or sufficient to test the Dinantian shale.
IGas Energy has identified 1.14 Tcf of 2P contingent resources of gas in place in the Bowland Shale equivalent on its acreage in North Wales. In South Wales Coastal Oil & Gas applied for permission to drill the Llandow gas shale exploration well to a depth of 2,130 ft to log and core the Namurian Millstone Grit Shale Group, the Dinantian Upper Limestone Series and Lower Limestone Series, and possible gas shale in the Ordovician, in addition to Devonian tight gas. Despite this well being drilled on the same basis as previous coal seam gas exploration wells drilled

in the area by Coastal in 2007/8, the company withdrew the application in the face of local opposition to the drilling.
In June 2011, Australia's Dart Energy (formerly Composite Energy) announced the results of an independent assessment of shale resources in PEDL 133 in the Midland Valley of Scotland by Netherlands Sewell & Associates. This indicates an estimated gas-in-place of 0.8 Tcf in the Namurian (Upper Mississippian to Lower Pennsylvanian) Black Metals Member (Limestone Coal Formation) of the Kincardine Basin at depths of 300 m to 1,200 m, and with a potential resource of 0.1 Tcf. The deeper Visean (Middle Mississippian) shales of the Lawmuir and Lower Limestone formations are estimated to contain 3.6 Tcf gas in place with a gross resource of 0.5 Tcf. Dart Energy owns 100% of the Namurian prospect but BG has a 50% interest in the Visean prospect.

Ireland
Enegi Oil has taken out option ON11/1 to evaluate the shale gas potential of the Namurian (Upper Mississippian – Lower Pennsylvanian) Clare Shale in western Ireland. The Clare Shale is known to have high levels of thermal maturity so the issue here may be whether it is overmature for gas. In the Northwest Ireland Carboniferous Basin (Lough Allen Basin), which straddles the border between the Irish Republic and Northern Ireland, Tamboran Resources and the Lough Allen Natural Gas Co have taken out licences on both sides of the border to evaluate the potential of the Visean (Middle Mississippian) Bundoran and Benbulben shales, both of which yielded strong gas shows in wells drilled in the mid-1980s.

3.3.3 Liassic (Lower Jurassic)

The third major regional play comprises Lower Jurassic bituminous shales that are being targeted in the Weald Basin (southern England), Paris Basin, the Netherlands, northern Germany and Switzerland's Molasse Basin. In continental Europe, the principal target is the Lower Toarcian Posidonia Shale. In eastern Germany and Poland the Lower Toarcian grades into a terrestrial facies and loses its source potential. In southern England the principal bituminous shales are older and occur in the Lower Lias. These bituminous shales are clearly oil-prone. The principal limitation regarding their shale gas potential therefore lies in finding locations in which they have been sufficiently deeply buried to have entered the gas window. Locations where this may have occurred include the flexural foreland basin of the Swiss Molasse and the Mesozoic depocentres of the Lower Saxony Sub-basin (Northwest German Basin) and the offshore Broad Fourteens Basin and Central Graben of the Netherlands. In those deeper sections of the Posidonia Shale, vitrinite reflectance values (R_0) in the range of 1–1.5% indicate a sufficient degree of thermal maturity to enter the dry gas window. TOC values are here in the range of 1–14% with an average of 5.7% (Horsfield et al. 2010).
A number of companies are thought to be investigating Lower Jurassic shale gas potential. These include Cuadrilla Resources in England's Weald Basin and Schuepbach Energy in Switzerland's Molasse Basin. Whether the Liassic shales will be within the gas window in the Weald Basin remains to be seen though it is possible that they may have generated biogenic gas at shallow depths.

Germany
The US EIA (2011) estimation for economically recoverable potential of the Posidonia Shale in Germany is 7 Tcf. In Germany the ExxonMobil / Shell co-venture (BEB) commenced shale gas exploratory drilling in 2008 in the Lower Saxony Basin, drilling Damme-2/2A and 3 in the Munsterland concession and Oppenwehe-1 in Minden. Schlahe-1 was drilled in 2009 and Niedernwöhren-1 was spudded in the Schaumburg permit in October 2009. Damme-3 is known to have been frac tested (three fracs). Posidonia

Shale is presumed to have been at least one of the targets for these wells. ExxonMobil spudded Lünne-1 (Bramschen concession, Emsland) around 17th January 2011 and reached the Posidonia Shale at 1,438 m. The well is planned to have a 500 m horizontal leg. In March 2011 Lünne-1A (the horizontal leg) was drilling. BNK Petroleum (six concessions) and Realm Energy (one concession) have also announced the Posidonia Shale as a target. Wintershall received permission from the relevant mining authorities in August 2010 to conduct G&G studies in an area of about 4,000 km^2 stretching from the German-Dutch border to Middle Germany (Fig. 7). It is planned to explore the shale gas potential of this area for a period of three years. It is an open question whether this area turns out to be prospective.

3.3.4 Other plays with shale gas potential

Austria

OMV is investigating the potential of the Upper Jurassic Mikulov Formation in the Deep Vienna Basin. The company estimates that the formation contains 200 – 300 Tcf of gas in place of which 15 Tcf may be recoverable. The target occurs at depths greater than 4,500 m and a temperature of 160° C. The same formation may have potential in the Czech Republic where BasGas (now Hutton Energy) and Cuadrilla Resources have applied for acreage.

Bulgaria

The Lower to Middle Jurassic of the Moesian Platform, especially the basal Stefanetz Member of the Middle Jurassic Etropole Formation, is a target in northern Bulgaria,

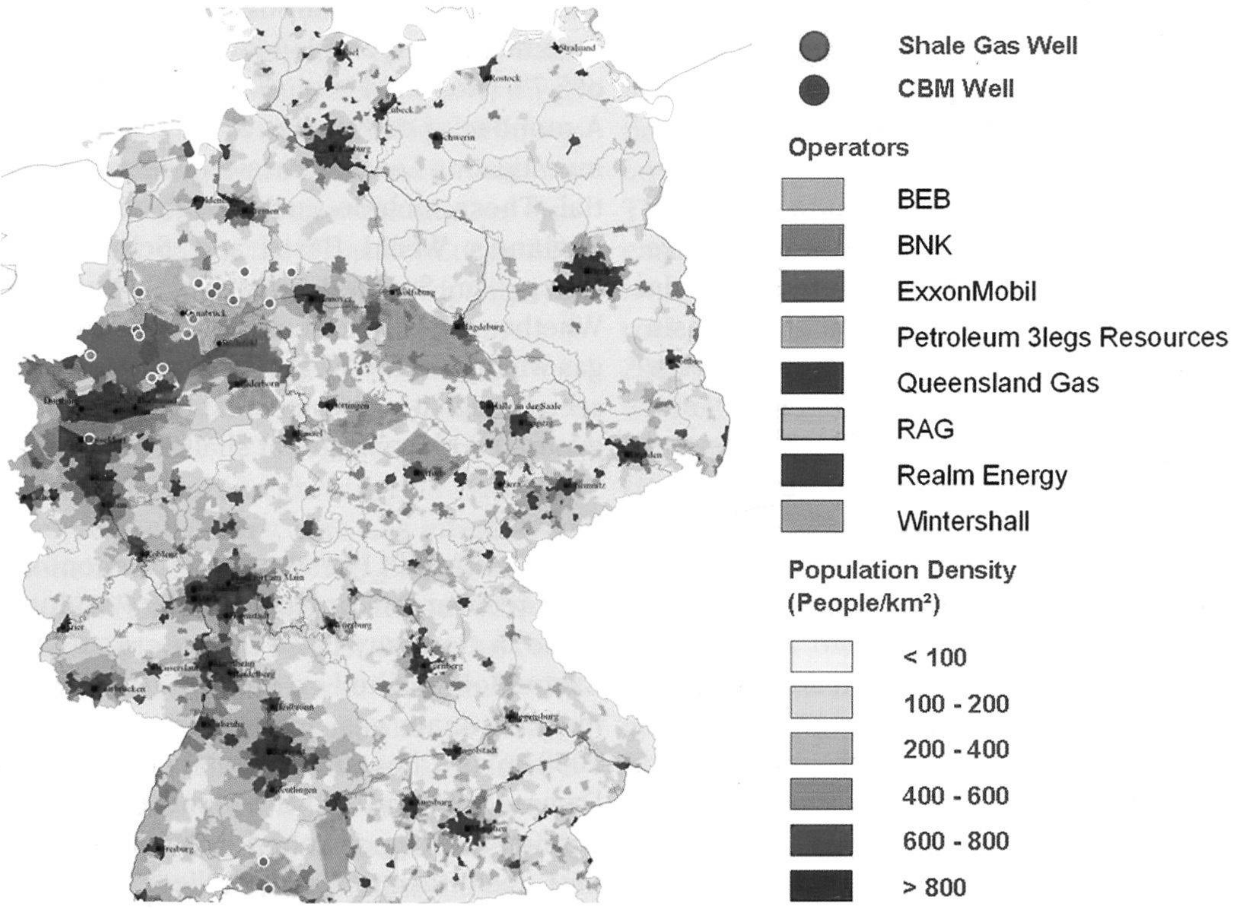

Fig. 7: The challenge of highly populated areas – Shale gas and CBM exploration concessions (Sep. 2011) and population density. The red dots show shale gas wells, the blue dots indicate the locations of CBM wells.

where both Direct Petroleum (Transatlantic Petroleum) and Chevron now have licences.

France

Permo-Carboniferous basins in the Languedoc such as the Stephanian-Autunian (Upper Pennsylvanian – Lower Permian) Lodève Basin may have some potential in bituminous Autunian (Lower Permian) shale. Schuepbach Energy has been awarded two permits in the Landguedoc-Provence Basin, one of which also incorporates part of the Lodève Basin. (GDF Suez is in discussions to become a partner in these blocks.) Total has been awarded the Montelimar permit. A number of other companies have also applied for permits in Languedoc-Provence, many of them overlapping. Elixir Petroleum is exploring for shale gas (and tight gas) in the Permo-Carboniferous of the Moselle concession in the eastern Paris Basin, where in the past at least two wells have produced gas to the surface from the target interval (probably Carboniferous). In the main Paris Basin many conflicting applications have been filed. While the main focus of these is probably Liassic shale oil, a number are presumably also targeting shale gas potential in underlying Permo-Carboniferous half-grabens.

In February 2011, shale gas and shale oil drilling in France was suspended by the authorities pending a progress report on the environmental consequences of shale exploitation. The ultimate outcome of this process was the passing of a law on 13th July 2011 that prohibited the exploration for, and production of, liquid or gaseous hydrocarbons by hydraulic fracturing. Permit holders have two months in which to advise the administrative authorities of the techniques that they use or intend to use in their exploration activities. Failure to respond or an intention to use hydraulic fracturing will result in withdrawal of the permit. A national commission will also be established to evaluate the environmental risks associated with hydraulic fracturing and to set out the conditions under which scientific research under public control can take place. The government will report annually to parliament on the evolution of exploration and production technology in France, Europe and internationally and also on the results of the scientific research undertaken.

In September 2011, major French E&P company Total S.A. announced in its report to the authorities that it would continue the evaluation of its Montélimar exploration licence but that the work programme does not envisage the use of hydraulic fracturing. Other companies are expected to adopt a similar approach.

Germany

The Upper Devonian Kellwasser shale has been touted as having potential in northern Germany, as have Wealden paper shales of Berriasian age in the Lower Saxony Sub-basin, where ExxonMobil/Shell encountered 620 m of Wealden sediment in Oppenwehe-1 in 2008. Realm Energy also sees the Wealden as a potential target on its Aschen concession. In the Bodensee Trough, north of the Swiss-German border, Parkyn Energy, another 3Legs Resources subsidiary, has taken out two licences in which the principal prospect appears to be lacustrine shale of Permian age (Fig. 7).

Hungary

The shale gas exploration situation in Hungary is unclear. In September / October 2009, Falcon Oil & Gas/ExxonMobil/MOL tested an Upper Miocene basin-centred gas prospect in the Makó Trough (Pannonian Basin) with only limited success, after which ExxonMobil and MOL exited the project. But Falcon has suggested that its acreage holds a «potential fractured oil and gas play». MOL and its part-owned subsidiary INA have indicated that the Miocene of the Mura and Drava sub-basins (Pannonian Basin) of eastern Croatia has shale gas potential and it can be assumed that this extends into western Hungary.

Italy
A shale gas/coal seam gas combination play is being investigated by Independent Resources in the Ribolla Basin, Tuscany. Upper Miocene (Messinian) gas shale straddles a coal seam of up to 6 metres thickness over a distance of tens of kilometers along the basin axis. Farm-out discussions are under way with companies, which have experience of analogous plays.

Netherlands
The Upper Jurassic Kimmeridge Clay is sufficiently deeply buried in the Central Graben in the northern Netherlands offshore to have reached the gas window. In view of the high well cost and drilling density likely to be required, it seems unlikely that offshore shale gas development will be economic in the foreseeable future unless an existing platform and wells happen to fortuitously located in an optimal location for shale gas development.

Romania
Chevron and Sterling Resources/Transatlantic Petroleum have acquired a number of licenses in the Moesian Platform of the East European margin in the south of the country, along the Bulgarian border. The targets are believed to be shale of Silurian to Lower Devonian age (Tandarei Formation) and Middle Jurassic age (Bals Formation). Chevron has also acquired a concession (Barlad) on the platform margin in northeast Romania where the Silurian foredeep shales that are prospective in Poland and Ukraine are also believed to occur.

Spain
Applications that are presumed to be for shale gas exploration have been submitted in the Basque-Cantabrian Basin (BNK Petroleum; Hutton Energy; Leni Gas & Oil; SHESA), Pyrenean Foothills (Cuadrilla Resources) and the Campo de Gibraltar (Schuepbach Energy/Vancast). Realm Energy has made a total of ten licence applications in the country. The targets in the Basque-Cantabrian Basin appear to be Lower - Middle Jurassic and Albian shales.

Switzerland
In addition to the Lower Jurassic Posidonia Shale, Schuepbach is also targeting the Aalenian (Middle Jurassic) Opalinuston in the Molasse Basin. It is understood, however, that the cantonal authorities in Fribourg will not renew the Fribourg licence when it expires at end-2011 over environmental concerns. Schuepbach still hopes to explore for shale gas in Canton Vaud, to the south of Fribourg. Other companies like the American eCorp International and Celtique Energie Petroleum Ltd of London are investigating shale gas or shale oil opportunities in Switzerland, largely in the same stratigraphic intervals.

United Kingdom
The Upper Jurassic Kimmeridge Clay has been proposed as a possible target in the Weald Basin, England, but there is considerable doubt that it will be mature for significant gas generation in this basin, although biogenic shale gas may be a possibility. Cuadrilla's interest in the Kimmeridge Clay is for shale oil rather than shale gas. If there is shale gas potential in the basin it seems more likely that it will come from older shales (Rhaetic or older). For example, Esso's 1963 Bolney 1 well is reported to have found a marine Middle Devonian interval within the gas window.

4. Russian Activities

The Russian Federation contains the world's largest reserves of conventional natural gas. In 2010, with 1,581 Tcf its share was about 23.9% of the total global proved reserves of natural gas. The Russian Federation produced in 2010 20.8 Tcf of natural gas and consumed 14.6 Tcf (BP, 2011). Russia currently supplies more than half of Europe's gas imports. However, a large share of Russia's reserves of conventional natural gas is located in the remote polar Siberian regions, making both production and transportation cost-intensive. In areas that are not well served with conventional gas supply infrastructure, unconventional hydrocarbon resources development, and especially Coal Seam Gas (CSG), is likely to offer a local and cheaper alternative source of energy supply.

4.1 Coal seam gas

Coal basins of the Former Soviet Union are estimated to contain as much as 3,957 Tcf of potential undiscovered CSG resources in place (Holditch 2006, based on Rogner 1996), compared with conventional proven Russian gas reserves of 1,535 Tcf and probable gas resources of 8,560 Tcf (Gazprom 2011). Russian coalmines are also some of the most gas-rich, with an average of 400 scf of methane/t (Ruban et al. 2006).

The Kuznetsk Basin in southwestern Siberia is one of the largest coal mining areas in the world and may reasonably be considered as the world's largest among the explored CSG basins (Fig. 8). Its coal-bearing seams extend over an area of 26,700 km^2 and reach to a depth of 1,800 m. Overall coal deposits are estimated at 725 billion tonnes, with a CSG resource base of about 445 Tcf. These estimates are given for the coal and methane resources deposited at a depth of 1,800 - 2,000 meters. In the deeper coal deposits of the basin the amount of methane is estimated at 685 Tcf. The basin fill is Permian to Cretaceous in age, and is dominated by nonmarine siliciclastics up to 7 km thick (Davies et al. 2010).

In 2003 Gazprom launched a project to estimate the possibility of commercial CSG production in Kuzbass. The project included the drilling of four pilot wells in the Taldinskaya area of Kuzbass. In February 2010, Gazprom launched Russia's first coal seam

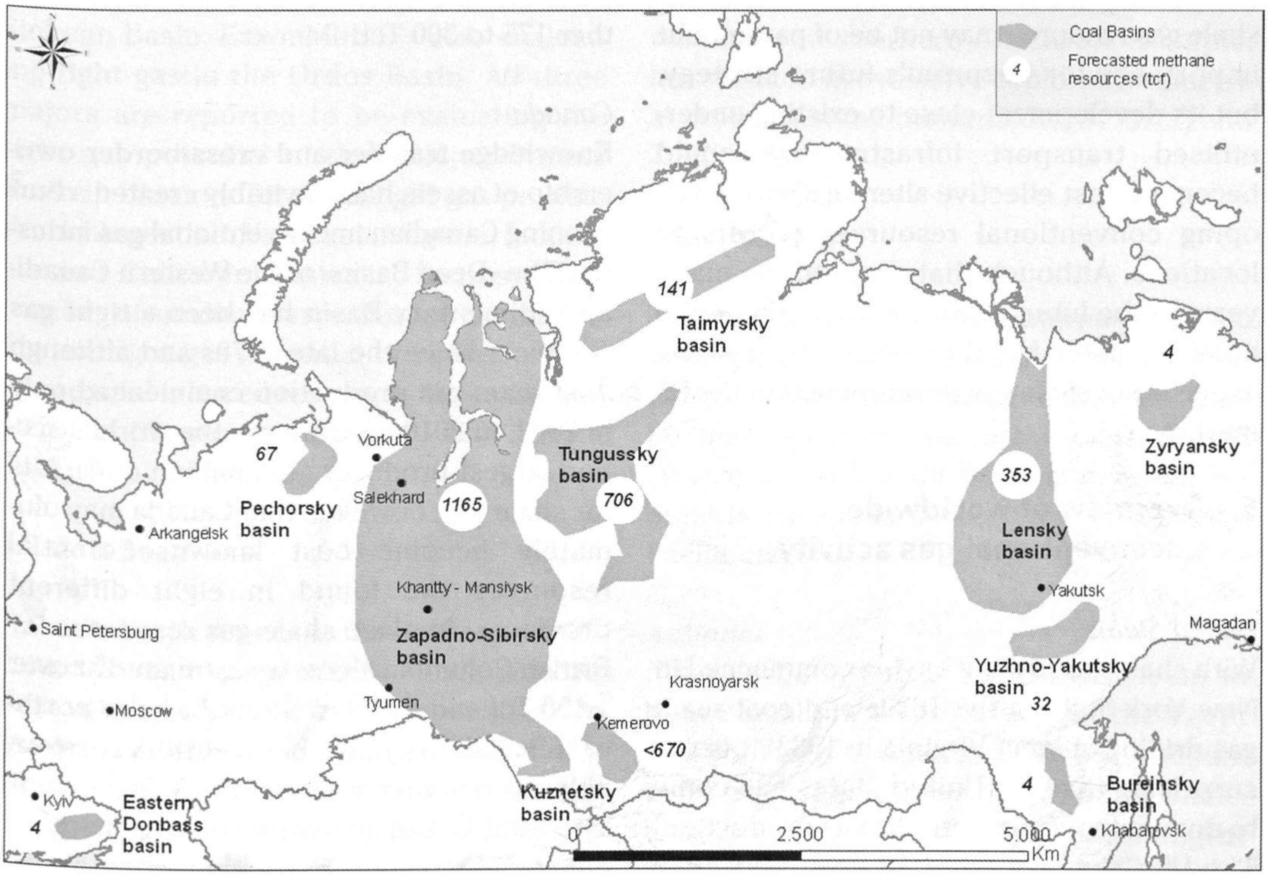

Fig. 8: Coal seam gas resource development in Russia. Figures are in place gas (Gazprom 2011).

gas production facility at the Taldynskoye field in the Kuzbass region. CSG production is here expected to increase from 140 bcf/yr to 600 - 700 bcf/yr in the long term in order to meet gas demand in the southern regions of West Siberia. The Taldinskoye field forecast resources are estimated at 3.26 Tcf (Gazprom, 2011).

4.2 Shale Gas

When it comes to shale gas, little is known about the country's potential of this resource and about the current status of activity, if any. The assessment of the country's resources still lays some way in the future, but 627 Tcf of shale gas is estimated as the in-place resource for the Former Soviet Union as a whole (Holditch 2006, based on Rogner 1996). The comparison with the Former Soviet Union in-place estimate of 3,957 Tcf of coal seam gas and 901 Tcf of tight sand gas and a possible in-place Russian resource of 40,000 Tcf of natural gas hydrates suggests that the development of the Russian shale gas resource may not be of paramount importance for Gazprom's future strategy, but its development close to existing underutilised transport infrastructure could become a cost effective alternative to developing conventional resources in remote locations. Although that may still be many years in the future, Gazprom is beginning to position itself for that future by gaining expertise of shale gas development in the US market.

5. Overview of worldwide unconventional gas activity

United States

With shale gas drilling having commenced in New York State in the 1820s and coal seam gas drilling in West Virginia in 1932, it is not surprising that the United States has come to dominate unconventional gas production. The US Crude Oil Windfall Profit Tax 1980 legislation provided incentives for the production of hydrocarbons from «a nonconventional source» including «Devonian shale, coal seams, or a tight formation» and this spurred interest in unconventional gas development. In 2008, non-conventional gas production exceeded 50% of all US gas production for the first time and production continues to rise (see Fig. 15, Section 9).

The ultimate recoverable US shale gas resource is presently estimated by the EIA at some 875 Tcf, of which 15 Tcf has been produced and 60 Tcf represents proved reserves, leaving some 800 Tcf of probable, possible and speculative resources. Another study estimates the unproved shale gas resource at 687 Tcf (Potential Gas Committee 2011).

The ultimate recoverable US coal gas resource is estimated at some 200 Tcf, of which 25 Tcf has been produced and 19 Tcf represents proved reserves.

Cumulative US tight gas production stood at over 150 Tcf at end 2009, while proved reserves are in the order of 60 Tcf and unproved resources may contribute a further 175 to 300 Tcf.

Canada

Knowledge transfer and cross-border ownership of assets has inevitably created a burgeoning Canadian unconventional gas industry. The «Deep Basin» of the Western Canadian Sedimentary Basin has been a tight gas producer since the late 1970s and although coal seam gas production commenced only in 2003, in 2010 Canada was the world's second largest producer (715 million cf/d). It is for shale gas, however, that Canada may ultimately become best known. Potential resources are found in eight different provinces. In-place shale gas resources for British Columbia alone are estimated at over 1,100 Tcf and the Horn River basin in northeast British Columbia has a current recoverable gas resource estimate of 78 Tcf.

The total Canadian unconventional in-place natural gas resource is estimated at about 3,200 Tcf (coal seam gas: 800 Tcf; tight gas from sandstone and carbonate: 1,300 Tcf; shale gas: 1,100 Tcf) (Petrel Robertson resource assessment study completed for the Canadian Society for Unconventional Gas, April 2010).

Rest of World
Outside North America, tight gas was first to be developed. This is understandable as it occurred as a result of the development of progressively tighter conventional reservoirs and accompanied improvement in fracturing technology. Much of the eastern hemisphere development has taken place in Europe (see Section 3).

5.1 Tight Gas

Elsewhere, much of the tight gas evaluation and development has been undertaken by the world's largest oil companies. BP has production from Algeria and is evaluating prospects in Jordan, Oman and Ukraine. Shell has production in China's Ordos Basin and is also investigating the potential of the Sichuan Basin. ExxonMobil is also evaluating tight gas in the Ordos Basin. All three majors are reported to be evaluating the tight gas potential of the Dnieper-Donets Basin in Ukraine. Total has tight gas production in Argentina, Venezuela, Algeria, Indonesia and China. In Australia, Santos and a number of smaller companies are investigating the tight gas potential of several states where total inferred resources are estimated at 20 Tcf (Geoscience Australia and ABARE 2010).

5.2 Coal Seam Gas

Outside North America, the earliest significant coal seam gas production took place in Australia, where there has been continuous production since 1996. Although since outstripped by Canada, Australian production is set to grow dramatically as a number of LNG (liquefied natural gas) schemes are now being developed to export coal seam gas from eastern Australia. Once again, the scale and complexity of these projects mean that many of the world's largest companies or companies with significant experience in gas developments are involved: BG; ConocoPhillips; PetroChina; Petronas; Shell; Total. 2010 production of 590 million cf/d was 20% higher than that of 2009. Total in-place coal seam gas resources (identified, potential and inferred) are estimated at just over 400 Tcf (Geoscience Australia and ABARE 2010).
Asia is the focus of most of the remaining international coal seam gas activity. China produced 96 million cf/d in 2010 and India 4 million cf/d. First production from Indonesia commenced in 2011 and exploration is being carried out in Vietnam.
Most countries with hard coal resources (bituminous rank or above) have the potential to produce coal seam gas so interest in exploring for, and exploiting, coal seam gas depends very much on whether alternative conventional supplies of natural gas are available. Lack of significant indigenous gas resources in southern Africa, for example, has resulted in extensive exploration and trial production in Botswana, South Africa and Zimbabwe.

5.3 Shale Gas

To some extent, interest in international coal seam gas development may have diminished as the true potential of shale gas has become apparent. As in the case of coal seam gas, much of the international activity outside Europe is taking place in the Asia-Pacific region.

Australia
Norwest Energy is awaiting permission to hydraulically fracture a well in the Perth Basin, Western Australia, which encountered a gross thickness of 1,040 m of shale. Beach Energy has booked 2 Tcf of contingent resources of sales gas after successfully flowing one of two vertical exploratory wells

drilled in the Cooper Basin, South Australia. While a number of small companies are active in shale gas exploration in Australia, larger international companies are also involved. China National Offshore Oil Corp. (CNOOC) is farming into Exoma Energy's Eromanga Basin acreage in Queensland, where the first two wells have encountered shale gas. QGC (a 100% subsidiary of UK's BG Group) has farmed into Drillsearch Energy's Cooper Basin acreage in Queensland, adjacent to the Beach Energy acreage in South Australia. Shale gas and tight gas are said to be the prospects.

India
State company ONGC produced gas from its first shale gas exploration well in the Damodar Basin, Gujarat State, and has identified four other basins where it wishes to investigate shale gas potential. A first licensing round is planned. Reliance Industries (RIL) has already taken stakes in US plays such as the Marcellus and Eagle Ford, which will place it in a good position when bidding. It may take some time, however, for the ministry to formulate its shale gas licensing policy, given the constraints on land use and water availability in certain parts of the country.

China
China has awarded two of the four blocks offered in its first licensing round. The offer was restricted to Chinese companies but it is understood that successful bidders are welcome to invite foreign companies to participate. Shell is cooperating with PetroChina parent China National Petroleum Corp. to evaluate shale gas in the Fushun block, Sichuan Basin, while ExxonMobil has entered into an agreement with Sinopec to assess shale gas potential in the same basin. In July 2011 Sinopec announced that it had completed its first horizontal shale gas exploration well, in the Jianghan Basin, east of the Sichuan Basin.

Concerns about hydraulic fracturing are not a purely North American and European phenomenon. The South African government has placed a moratorium on fracking in the Karoo Basin, where Shell is a leading rightholder.

6. Technical and environmental aspects

Among the three unconventional sources the shale gas reservoirs play a specific role. Whereas CBM and tight gas formations have permeabilities in the Millidarcy to Sub-Millidarcy range the permeability of shale gas formations is generally in the Micro- to Sub-Microdarcy range. For this reason much larger fracture areas are required for shale gas reservoirs in order to achieve economical gas production flow rates. The fractures required in CBM and tight gas formations are generally created by conventional low-volume hydraulic fracturing tests using high viscous fluids with a relatively high proppant concentration. Typical fluid volumes injected during conventional frac tests are between several tens to several hundred cubic meters and typical fracture lengths are between several tens and a few hundred meters. Shale gas frac-operations instead are high-volume high-flow rate tests using a low viscosity fluid (slickwater) with a low proppant concentration. Injected volume per frac-operation (frac-stage) is generally in the order of a few thousand cubic meters and it was only this recently developed slickwater frac-technique that made fracture length up to about 1 km technically and economically feasible.
Due to the large volume injected at very high flow rates slickwater frac-tests are very massive operations and most of the concerns in the public are directly or indirectly related to this fact. Unfortunately many technical papers on shale gas technology do not distinguish between the conventional «low volume» frac-tests and the «high volume» slickwater tests when arguing that hydraulic frac-

turing is a well established technique being used with great success and without major environmental problems in about 2 Million oil and gas wells during more than 60 years. As a result the environmental problems encountered at some shale gas locations are now generalized in the public and hydraulic fracturing is now criticized in general. In reality the environmental problems under discussion apply only to the slickwater frac-technique. For this reason the following chapters focus on this technology.

6.1 Technical components

Drilling

The rapid progress of the shale gas development is to a main part related to the combination of the horizontal drilling technique with the slickwater frac-technology. Not all wells in the shale gas reservoirs are however horizontal. Most of the earlier wells in the Barnett play (80% in 2003) for instance were vertical and still nowadays vertical wells are drilled. In most cases however horizontal drilling is the most economic solution and its environmental footprint is of course much smaller. Horizontal drilling became therefore more and more attractive and in 2009 about 97% of the wells in the Barnett shale were drilled horizontally. It is almost certain that horizontal drilling will become the dominant drilling technique also in future shale gas fields, especially in densely populated and industrialized regions like Northern America and Europe.

Horizontal wells are drilled vertical down to about a hundred meters above reservoir depth. Starting from this kick-off point they are gradually steered into the horizontal direction. In the reservoir the wells are drilled horizontally but they may also follow the dip of the reservoir. Typical horizontal shale gas wells have horizontal lengths of 0.5 to 1.5 km, but much longer horizontal sections are technically feasible.

Shale gas wells are cased with steel casings according to the standard of conventional gas wells. The so-called production casing is running from the bottom of the well or from the top of the reservoir to the surface. This casing has a high burst and collapse pressure. All fresh water aquifers - normally in the uppermost few hundred meters - are protected by at least one other steel casing, the surface casing which surrounds the production casing. Some geological situations or state regularities require a third so called intermediate casing which is in between the surface and the production casing. The annulus of all casings is filled with cement but not always over their entire length.

Hydraulic-Fracturing

The hydraulic-tests are performed in the horizontal part of the well. For this purpose the production casing is first «perforated» by using small explosive charges at intervals selected for fracturing the shale. These sections are then insulated by inserting multi-packer systems. These packer systems allow injecting the frac-fluid section by section. In this way a definite number of fractures can be created. Modern multi-packer-systems allow insulation of up to 30 intervals and are available for cased and uncased borehole sections.

It is generally assumed that the fractures created by injecting fluid at high flow rates and pressure are tensile fractures and are oriented perpendicular to the direction of the least compressive tectonic stress. Since for most tectonic settings the least compressive stress is horizontal, the horizontal section of wells is drilled parallel to the direction of the minimum horizontal stress in order to create fractures perpendicular to the bore-hole axis.

Because of the extremely low permeability of the shale gas reservoirs of 0.01 µD to 10 µD (GWPC 2009) much larger fracture surfaces than in conventional gas reservoirs are required. This means that much larger fluid volumes have to be injected. In the Barnett and Marcellus shale in the US the fluid volume used for each interval is in the order of one thousand to several thousands cubic meters and the total volume for a horizontal borehole adds up to ten thousands or even some ten thousand cubic meters (GWPC 2009). Fractures in shale gas reservoirs have typical half-lengths of 200 to 500 m and a height equal to the thickness of the shale gas reservoir (typically some 10 m to more than 100 m).

The opening and propagation of tensile fractures need a fluid pressure slightly higher than the minimum horizontal stress. In most cases this corresponds to a pressure of 10 to 30 MPa at the wellhead. In praxis the injection pressure at the wellhead is often much higher because of the additional friction pressure losses in the well when the fluid is pumped down at high flow rates.

Tensile fractures tend to close when the fluid pressure is released after the frac-operation due to the compressive action of the minimum horizontal stress and the elastic forces in the rock. In order to maintain a certain fracture width or fracture conductivity sand or other kinds of fine-grained material is added to the frac-fluid. These so called proppants settle within the fractures during the fracturing process and keep them open after releasing the pressure. The width of propped tensile fractures in shale is in the order of some millimetres.

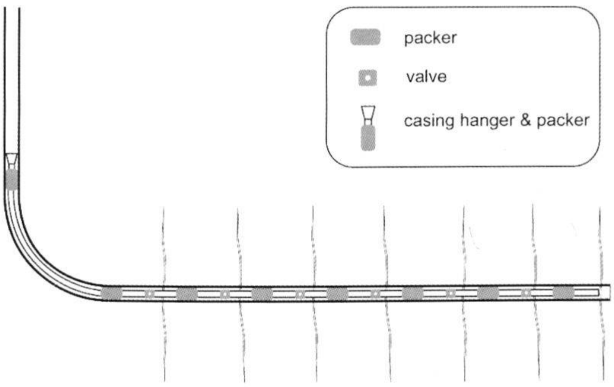

Fig. 9: Hydraulic fracturing. Scheme of a multi-packer assembly for shale gas wells. The valves can be activated individually so that one fracture after the other can be created starting from the bottom of the well.

The ability of the frac-fluid to transport proppants depends mainly on flow velocity, fluid viscosity, proppant-diameter and -density. Frac-fluids used in conventional gas or oil reservoirs are very viscous (> 0.1 Pa·s). For the large shale-fractures frac-fluids (slickwater) with a much lower viscosity of 0.001 Pa·s (viscosity of water) to 0.01 Pa·s is used. The main reason is to enable the frac-fluid migrating into natural fractures adjacent to the main fracture and causing them to open and shear. As a result a more complex fracture network is created with a bigger surface area exposed to the low permeable rock matrix.

In order to compensate for the negative impact of the low viscosity on the transport capability of the fluid, fine-grained and sometimes lightweight proppants are used. The biggest effect however is gained by applying extremely high injection flow rates of up to 0.4 m^3/s (Miskimin 2011). The pumping power needed for frac-operations in shale gas wells is therefore very high. It often exceeds several tens of MW and requires dozens of power-full high-pressure pumps operating at the same time.

In order to minimize the friction pressure losses, friction reducers are added to the frac-fluid. For the same reason the frac-fluid is pumped directly through the production casing and not through a temporary frac-tubing of smaller diameter as is normally done in conventional frac-tests. As a consequence the production casing is exposed directly to the high injection pressure and the relatively low temperature of the frac-fluid.

Micro-seismic fracture mapping

The shearing of secondary fractures and perhaps the propagation of the tensile fracture itself is accompanied by micro-seismicity. The magnitude of these seismic events is generally very small in shale gas reservoirs ($M < -1.5$) and can only be detected by ultra-sensitive seismometers in adjacent deep boreholes (Zoback et al. 2010). Modern data acquisition and analyzing software allow locating the sources of the seismic events in real time. This allows monitoring fracture growth during the test. It may therefore be possible to stop the frac-operation when the fractures start to propagate up-wards or are approaching natural faults or fracture zones, which could be potential flow paths to higher levels. Microseimic monitoring is now a mature technique but the majority of shale gas wells like other oil and gas wells have been fractured without seismic observations.

«Drilling and fracturing a typical horizontal well in the Marcellus shale (at about 2 km depth) takes about three weeks to complete and costs about \$ 3.5 to \$ 4.5 million» (Zoback et al. 2010). The costs for the frac-operations are often exceeding the drilling costs.

Flow back and production

After commencing the frac tests part of the frac-fluid is recovered by venting and stored temporary in tanks or open pits at the drill site. This flow-back period lasts for a few days up to several weeks. In various shale gas fields in the US the flow-back volume accounts for less than 30% to more than 70% of the original fracture fluid volume (GWPC 2009). The flow-back fluid is later reinjected into saline aquifers or dumped in rivers or streams after treatment.

Gas production from stimulated wells is quite variable and is decreasing with time due to the depletion of the reservoir pressure in the vicinity of the fractures, with a rapid decline at the beginning and stabilization thereafter. In the Barnett shale production flow rates are initially between 300 and 3,000 m^3/h and 150 and 1500 m^3/h per well after one year of production (King 2010). The EUR (Estimated Ultimate Recovery) is between 10 and 100 Mio. cubic meters per well (King 2010). Compared to wells in conventional gas reservoirs the gas flow rate is comparatively low. Deep gas wells in Northern Germany for instance often produce at flow rates of 10,000 m^3/h. Similar production rates are also achieved from 5 km deep horizontal wells in the Tight Gas formations in Northern Germany after multi-fracturing.

6.2 Environmental risks associated with the development of shale gas reservoirs

The rapid development of shale gas deposits in the US was associated with a number of incidents of water contamination, air pollution, and earthquakes. Even though the number of documented incidents was low (42 for more than 20,000 wells (MIT 2010; UPI 2011) they caused severe concerns in the public and among politicians in the US as well as in Western European countries. The main concerns are toward the massive slickwater-frac technique. Some state regulators in the US have been moving toward moratoria on hydraulic fracturing while risks are assessed in a study on the environmental impacts of hydraulic fracturing on drinking water resources coordinated by the US Environmental Protection Agency (Wood et al. 2011). An interim report of this study is expected for 2012.

In the following the major potential impacts of the shale gas development and measures to prevent them are discussed briefly.

Unintended vertical fracture growth

One of the major concerns in the public toward the massive frac-technology is that the fractures may grow upwards and may finally connect the shale gas formation with near surface fresh water aquifers (UBA 2011). Frac-experts from the oil- and gas community however state that this is impossible or at least extremely unlikely due to the great depth of the shale reservoirs (Table 2) and the presence of soft or ductile rock layers like mudstone in the cap rock. The latter would act as a stress barrier stopping the fractures to grow upward. Another argument is that the gas producers themselves have the greatest interest in the fractures to be confined in the reservoir rock in order to prevent water influx into the reservoir.

The arguments of the experts are based mainly on their long years of experience with frac-operations in conventional gas- and oil-reservoirs (some 50 years) and on numerical simulations of frac-propagation, which is routinely done for the design of each frac-operation. Conventional reservoirs have usually comparatively low horizontal stresses due to their low Poisson ratio of 0.2 to 0.25. This favours longitudinal fracture growth in the reservoir and there is little chance for the fractures to grow upward when the cap rock is for instance comprised of mudstone or carbonates with a Poisson ratio of 0.3. Shale reservoirs however can have Poisson ratios of 0.3 or more. Vertical confinement of the fractures is therefore less certain in shale and it is rather surprising that micro-seismic fracture mapping of some 2,500 wells in the Barnett shale clearly indicate vertically confined fractures (Fig. 10). Similarly Cipolla et al. (2008) mention the occurrence of «extreme fracture height confinement that is not explained by variations in rock properties and stress».

Real-time micro-seismic fracture mapping and continuous pressure monitoring in saline or freshwater aquifers as well as in-situ stress measurements in the cap rock should therefore be integral parts of future massive fracturing campaigns.

Another argument of opponents is that even vertically confined fractures might eventually connect to permeable faults or fractures zones and that by this a hydraulic connection to near surface fresh water aquifers is established. Major faults can however be detected and mapped with modern 2D- or better 3D-reflexion seismic surveys and may in most cases be avoided by not drilling into the proximity of these faults.

Basin	Depth to Shale [m]	Depth to Aquifer [m]
Barnett	2,000 – 2,600	370
Fayetteville	300 – 2,100	150
Marcellus	1,200 – 2,600	260
Woodford	1,800 – 3,400	120
Haynesville	3,200 – 4,100	120

Tab. 2: Fracturing and aquifers: Depth to top of shale and base of aquifers in different shale gas regions of the US (after MIT 2010).

Integrity of the casing and of the cemented annulus

Another concern in the public is that natural gas, fracturing fluids, and formation water containing high concentrations of dissolved solids may travel through leaks in the casing or along the cemented annulus from the reservoir into fresh water aquifers. This problem is not specific for shale gas wells but is relevant also for conventional wells. Because of it's importance high industrial standards exist for the proper design, installation, and cementation of the casings. It seems that during the shale gas rush less experienced companies not always followed these standards. «For example in 2007 a 1200 m deep well in a tight sand formation in Brainbridge, Ohio was not properly sealed with cement, allowing gas from a shale layer above the targeted tight sand formation to travel through the annulus into an underground source of drinking water. The methane eventually built-up until an explosion in a residents' basement alerted state officials to the problem» (Zoback et al. 2010). This kind of problems can to a high degree be prevented by technical measures like pressure testing of the annulus after cementation, repeated cement bond logs, and control of the drilling and service companies, processes that are well developed and used in the industry.

A casing problem specific for shale gas wells results from the fact that for most frac-tests the slickwater is pumped through the production casing and not through a temporary frac-tubing. This means that the production casing is directly exposed to the high fluid pressure and the relatively cold injection fluid. During backflow the pressure is low and fluid temperature is high. Both the changing pressure and temperature induce high stresses in the casing and the cement. These stresses are of course calculated and considered in the design of the casing and cementation. Nevertheless the safety margins can be small and there remains a risk that these stresses may exceed the strength of the casing and more likely of the cement, especially in very deep boreholes. Installing a temporary frac-tubing for frac-tests and the flow back period can considerably reduce this risk. This however would mean to reduce the flow rates during frac-tests significantly.

Induced seismicity

It is well known from different applications like the hydraulic stimulation of geothermal wells and dumping of wastewater, that massive fluid-injection in deep wells may induce weak earthquakes. A series of small earthquakes with magnitudes of up to 3.3 in the Barnett shale area in 2008 and 2009 raised therefore the question whether these earthquakes were caused by the frac-tests. An investigation however indicated that most likely the dumping of wastewater into saltwater disposal wells in the vicinity caused the seismic activity (Zoback et al. 2010). The induced seismicity of the frac-tests had local magnitudes of less than -1.5 and a comparative study of induced seismicity in more than 40 geothermal and other projects, performed by scientists of the ETH Zurich showed that hydraulic stimulation tests in sedimentary rock are generally associated with much smaller magnitudes than tests in crystalline rock (Evans et al. 2011). The strongest seismic events so far were observed in a 2,700 m deep shale gas well in NW England with local magnitudes of 2.3 and 1.5 (see chapter 3.3.2). But even these events are barely noticeable at the surface. Altogether it seems unlikely that induced seismicity will become a major obstacle for the future development of shale gas

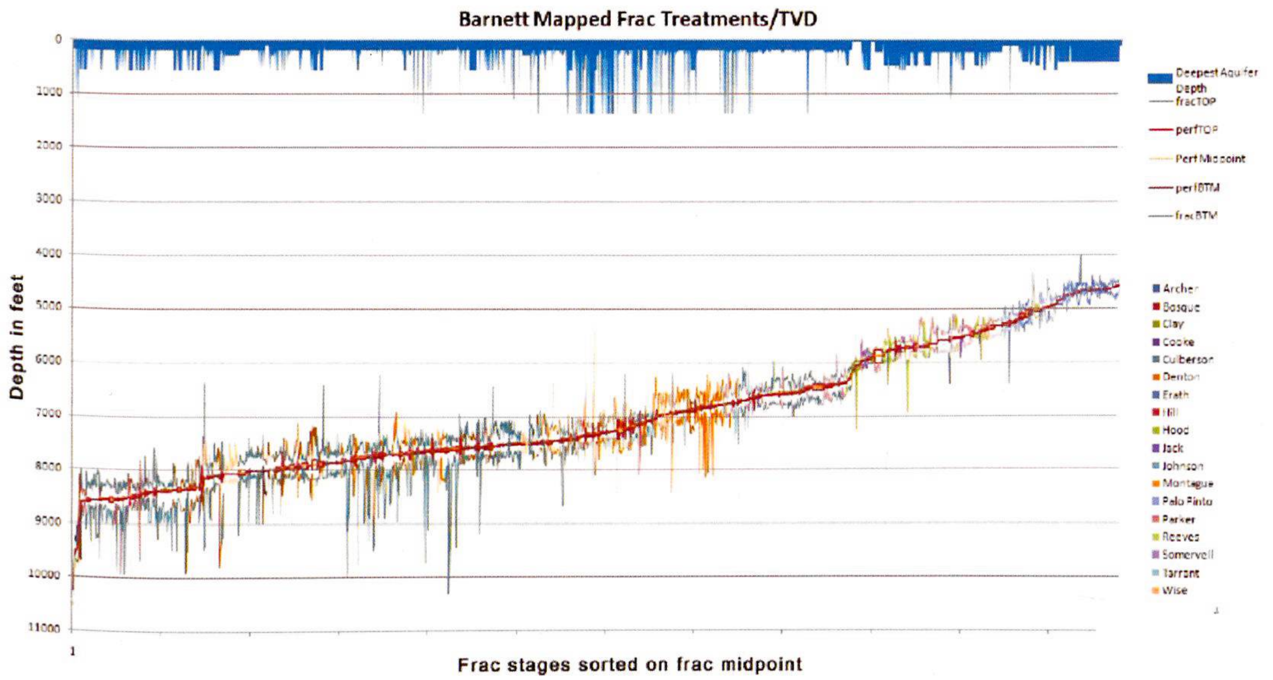

Fig. 10: Groundwater protection: Hydraulic fracturing and aquifers. Top and base of monitored induced seismicity (indicating size of fractures) recorded from about 2,400 hydraulic fracturing stimulations in the Barnett shale (wiggles in the bottom part of the diagram) and depth of the deepest aquifer at each frac-location (bar chart in the top part of the diagram). Courtesy Kevin Fisher, SPE Groundwater Protection Summit, Woodlands TX, 2011.

deposits. It is nevertheless advisable to install and operate permanent seismic surface monitoring networks in shale gas regions under development.

Toxicity of the frac-fluid

In Europe the frac-technique, as applied in shale gas projects, is mainly criticized for injecting large quantities of toxic fluid into the subsurface. Proponents of the shale gas development in turn argue that chemical additives comprise only a small fraction of the frac-fluid (generally less then 2%) and that most of them are not or only slightly toxic (GWPC 2009).

The «quantity-argument» is not really convincing. Despite their low concentration the total amount of chemical additives used in shale-frac tests is far from negligible. Two percent of 25,000 m^3 of slickwater correspond to about 500 t of chemicals used for the frac-tests in a single horizontal well. This adds up to 3,000 t for a well pad consisting of 6 horizontal wells. Considering the ten thousands of wells drilled in large shale deposits like the Marcellus play many Millions or even tens of Million tones of chemicals will be used for a single deposit.

The «quality-argument» convinced the opponents even less. To a big part this is owing to the unwillingness of the service companies to disclose the composition of their frac-fluids by declaring them as trade secret. To another part it is the great number of chemicals in use. «In a 2009 survey the New York State Department of Environmental Conservation received a list of some 200 chemical additives that companies might use in fracturing fluids» (Zoback et al. 2010). For most shale gas frac-operations however only about a dozen additives is used.

Even though there is a tendency to reduce the number and amount of chemical additives in shale-gas applications the service companies might not really be interested to do so. The design of fracturing-fluids is one of their key competencies in which they have invested billions of dollars and which now constitutes a significant part of their income. Nevertheless pure water fracs can be done successfully (e.g. geothermal well Basel-1).

Flow back fluid

A substantial part of the frac-fluid is recovered during the flow back period following the frac-tests. This fluid is temporarily stored in tanks or open pits at the site before it is transported to a disposal well or a treatment facility. On the average less than 30% to more than 75% of the frac-fluid flows back (GWPC 2009). This adds up to volumes from less than 5,000 m^3 to more than 15,000 m^3 per (horizontal) well. Considering the great number of wells in a shale gas deposit this would be a high additional load for the local treatment facilities if the fluid could not be injected directly in disposal wells. Spilling during handling and transportation of the fluid as well as leakage from pits has been reported for some locations.

An even bigger fluid volume may be produced with the gas during the lifetime of the wells. The water content of shale gas deposits is quite variable. In the Marcellus shale it ranges from 0 to 0.3 m^3 of water per m^3 of rock (Sumi 2008). Assuming a gas content of 10 m^3 per m^3 rock and a gas production rate of 1,500 m^3/h up to 45 m^3/h may be produced during the initial «dewatering period» of the well that may last for several months to 1.5 years in different shale deposits. Some wells in the Barnett shale produce water during the total lifetime of the wells at rates of 2.6 m^3/h to 3.3 m^3/h (Sumi 2008). This corresponds to 23,000 m^3/a and 29,000 m^3/a respectively. Other wells and wells in other shale regions, e.g. in the Lewis and Fayetteville shale may however produce almost dry gas.

The water produced with the gas is usually saline and can contain naturally occurring radioactive material (NORM) as well as other contaminants like arsenic, benzene, and mercury (Zoback et al. 2010). The most convenient disposal method is reinjection into deep saline aquifers as is done for instance in the Barnett shale. In regions with an insufficient number of disposal wells like the Marcellus shale the water is usually treated and disposed in rivers or streams. Activities to recycle or desalinate the water also for agricultural use are in progress.

Water consumption

In the average about 13,000 m^3 of water is needed for a shale gas well. About 90% of which is used for the frac-tests and 10% for the drilling. In the Marcellus shale the projected peak demand is estimated to 32,000 m^3/d or 12 Mio m^3/a (GWPC 2009) assuming that about 900 wells are drilled per year. This corresponds to the water consumption of about 100,000 people or the cooling of a conventional power station with about 600 MW. This is significant but the following estimate may put it into the right perspective:

The gas produced from a well with an expected ultimate recovery of 30 Mio m^3 can produce an electrical energy of 120,000 MWh. The water consumption for drilling and fracturing the well corresponds therefore to a specific water consumption of about 0.1 m^3/MWh. Conventional power plants fired by coal or oil are exhausting water between 1.9 and 2.6 m^3/MWh and nuclear power stations even 3.2 m^3/MWh of water in the cooling towers. Gas turbines in turn can produce power with almost zero water consumption.

This shows that on a broader scale water demand of the shale wells is not really of importance. Shale gas development has rather the potential to reduce the water demand of a country significantly if a substantial part of the gas is used for power production and not just burned for space heating.

On a local scale however availability, transport and storage of water can be a problem. The use of flow backwater or from saline aquifers as well as transportation by temporary pipelines could help to minimize this problem.

Land use

Shale gas development is also criticized for it's excessive land use. This may be examined by the following considerations: In conventional gas deposits like the Northern German gas fields the average distance between neighbouring gas wells is in the range of 1.5 - 3 km. This means that the drainage area of a well (the area that one well can exploit) is 2-10 km^2. Due to the low permeability of the shale gas deposits the drainage area is much smaller. Typical numbers are 0.15 km^2 for a vertical well and 0.6 km^2 for a horizontal well (Fig. 11). Exploiting a shale gas deposit by drilling individual vertical wells from separate drill sites and connecting them by pipelines and roads would therefore use between 15 to 70 times more land for the drill sites and facilities than the wells in a conventional Northern German gas deposit.

If however a set of 6 horizontal wells is drilled from a single pad, as is done today in the US, they would drain an area of about 4 km^2. This is comparable to the drainage area of a gas well in the conventional fields. The only difference is that the land use for the pad including facilities and the pit for the frac-fluid may cover an area of about 40,000 m^2 instead of about 10,000 m^2 or less for a conventional well. Gas production in the Northern German gas fields is hardly visible for the public and nobody has blamed the producers of excessive land use in the past. Concerning land use, the situation shouldn't be much different in a shale gas region if horizontal wells are drilled in pads.

The move toward pad drilling will intensify: up to 28 wells per pad have been drilled by Apache in the Horn River Basin.

Another perspective may be also interesting. The gas produced from about 230 wells in the Northern German gas fields could produce more than 5,000 MW or 46 TWh/a of electrical power if burned in gas turbines. For comparison, the omnipresent windmills in Germany produced 36 TWh/a, though their number and land use were much higher (21,000 wind turbines in 2010).

Traffic, noise and air pollution

When the wells are drilled in pads from one site - as will likely be the case in Europe - the burden on the public by the additional traffic, noise and air pollution will not much differ from the burden arising from drilling a single conventional gas well. Many activities like the construction of access routes and drill site, the mobilization and demobilization of the drilling rig would be done only once for a pad. The only difference is that drilling and fracturing activities would extend over a longer time period up to 1.5 years. Noise and exhaust of modern drilling rigs can however be so small that they can even be used in residential areas.

The disturbance arising from the frac-tests can be more serious. The massive shale frac-tests as they are done today are really big operations. A big number of huge pumps and tanks, and a large amount of additional equipment has to brought to the site in a short time and be removed after the frac-operation. Noise and exhaust of the pumps during the operation are usually quite significant. The frac-tests are however short - a few hours only - and most of the drill sites will be far from residential areas.

The major disturbance could result from the transportation of the water for the frac-tests and of the flow-back fluid. Several thousands of truck movements would be required if the water is transported by tank-trucks. At least for the water this is unlikely to happen in Europe since water is usually available within short distances from reservoirs, lakes, rivers, creeks, and channels or from shallow aquifers. For most sites it will therefore be transported via temporary pipelines. For the flow back this would also be the first solution. But this depends on the accessibility or distance of disposal wells or treatment plants.

The CO_2-emission of all drilling and frac-activities including transportation is in contrary to the external impression comparatively low. It accounts for only a few percent of the CO_2-emission from the combustion of the gas (estimated by using data of Wood et al. 2011).

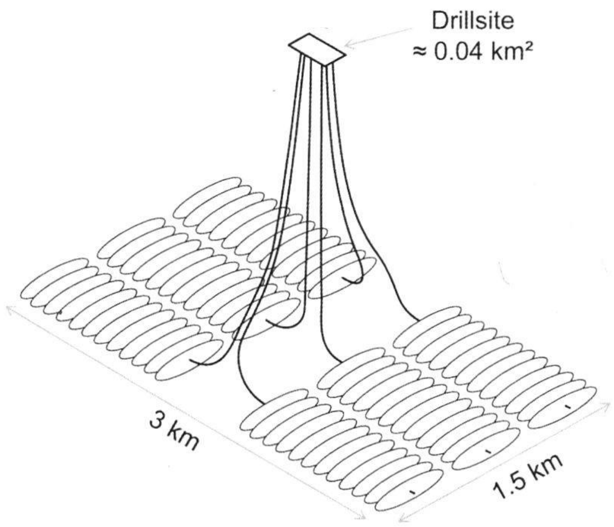

Fig. 11: Low surface impact through well pads / clusters. Scheme of a pad of 6 wells with multiple fractures (ellipses). The surface area (drill site) needed for drilling and hydraulic-fracturing covers less than 1% of the pad area.

6.3 Technical challenges and possible solutions for Europe

The most obvious weakness of the present shale-gas technology is the low production flow. Gas flow rates between a 150 and 1500 m^3/h per well would hardly be economical for (Western-) European conditions since the costs for drilling and fracturing are considerably higher than in the US. This is caused by the stricter environmental regulations and the less competitive contractor market. For the present energy prices the production flow rates should be at least by a factor of 3 to 10 higher to make shale gas production really attractive in Europe.

This however requires much larger fracture areas. Because of the very low permeability

of the rock matrix a total fracture area in the order of a square kilometre is required for a horizontal well. The present tendency is therefore to stimulate complex fracture networks comprising of a main propped fracture imbedded a network of secondary fractures (natural joints and fissures) that have been sheared and widened by the fluid leak-off from the main fracture during fracture propagation. This process needs low viscosity-fluids and time. The former is accounted for by using slickwater instead of the high viscous gels used in conventional frac-tests. Time however is a problem since the proppant transport needs very high flow velocities. As a consequence the test duration is short. The use of proppants and the stimulation of secondary fractures lead therefore to a conflict that cannot be solved without a radical change in the fracturing concept.
This change is possible. Hydraulic-fracturing tests in crystalline rock in Hot-Dry-Rock-Projects demonstrate since more than 30 years that highly conductive fractures can be created in hard rock without using proppants (Pine & Batchelor 1984; Jung 1989, 1991; Evans et al. 2005; Cornet et al. 2006). Water injection tests in coal seams point in the same direction (Rummel 2011). The success of these tests is explained by the so-called self-propping effect. This effect appears when the fractures due to the increased fluid pressure start to shear. The shear displacement results in a misfit of the two opposite rough and uneven fracture surfaces. The fractures will therefore not close when the fluid pressure is released. These results are hardly observed in the oil- and gas community and only some lone voices (Warpinski 1991, Mayerhofer et al. 1997; Walker et al. 1998, Cipolla et al. 2008) discussed or investigated similar mechanisms and proppant-free fracturing applications in unconventional gas reservoirs. Changing to a proppant-free-fracturing concept would have significant benefits:

- Less or no chemicals are used.
- Less pumping power and equipment is needed.
- Casing and cement can be protected by a frac-tubing.
- Upward fracture growth is less likely.
- Less noise is produced.
- Less truck movements for mobilization and demobilization are required.
- The costs are lower.

7. Global potential of unconventional gas resources

Why is unconventional natural gas important?

Whereas in 2009 unconventional hydrocarbon liquids (oil sands; extra-heavy oil; self-sourcing oil reservoirs; thermal shale oil) accounted for some 2.3 million barrels per day or 2.8% of world liquids production from fossil fuels, worldwide unconventional natural gas production was at least 35 bcf/d, 12% of the total world production of 289 bcf/d. The unconventional gas estimate is a minimum, as most countries do not report production from tight sandstone separately from that of conventional production from sandstone reservoirs.
In the United States, unconventional natural gas now accounts for over 50% of all gas production, having risen from 14.5% to 56.4% of total production in the 20-year period from 1990 to 2009 (Fig. 12). Shale gas production, which represented just over 15% of US natural gas production in 2009, is estimated to have increased to 13.3 bcf/d in 2010, more than 22% of total US gas production.
Unlike unconventional liquids, for which the established resources are concentrated in the western hemisphere in Canada, the USA and Venezuela, part of the attractiveness of unconventional natural gas is that the distribution of potential resources is geographically widespread. This is because the self-sourcing reservoirs that account for much of the unconventional natural gas resource (coal seams; organic-rich shale within the gas window) have a widespread distribution

and for many countries they therefore offer the prospect of security of supply.

A further attraction of resource plays in general (liquids and gas) is that, with little exploration risk, the development of resource plays has become very much like a manufacturing process. Large numbers of step-out wells may be drilled to better understand the geology and identify «sweet spots», in a process similar to determining ore grades in mining, development takes the form of regular extension drilling in order to maintain stable production levels.

How large is the unconventional gas resource?

Global estimates of unconventional natural gas resources are notoriously suspect. With the possible exception of coal seam gas, no reliable estimates of regional / global unconventional natural gas resources exist outside North America.

Frequently quoted and apparently modern and authoritative sources of in-place estimates (e.g. US National Petroleum Council, 2007; Holditch, 2006; Kawata & Fujita, 2001) all ultimately point back to Rogner (1996), who in turn relied heavily on the late-1970s estimates of Kuuskraa & Meyers published in 1983.

But when the methods of estimation used by Rogner and Kuuskraa & Meyers are examined in detail, it can be seen just how subjective and potentially unreliable they are. Rogner introduced his table of unconventional gas resource estimates by saying: «In summary, the data in the following tables have to be taken with a large grain of salt. This is particularly the case for the regional distribution which in many cases is highly speculative» (Table 3).

Even today, estimates of in-place resources for the most highly explored region (North America) show a considerable range and in most cases a significant difference from those of Rogner. In-place tight gas in North America, for instance, is currently believed to be in the order of 8,000 Tcf, some six times greater than Rogner's estimate of 1,375 Tcf.

Estimates of recoverable resources also show considerable uncertainty. For example, for US shale gas for which tens of thousands of wells have been drilled and where production in 2010 reached almost 5 Tcf, the US Energy Information Administration (2011b) has adopted an estimate of 827 Tcf of unproved technically recoverable resource but considers that, depending on whether certain assumptions turn out be more or less favourable, the potential range is 423 Tcf to 1,230 Tcf. Any estimates for the rest of the world, where there is as yet no shale gas production and the number of

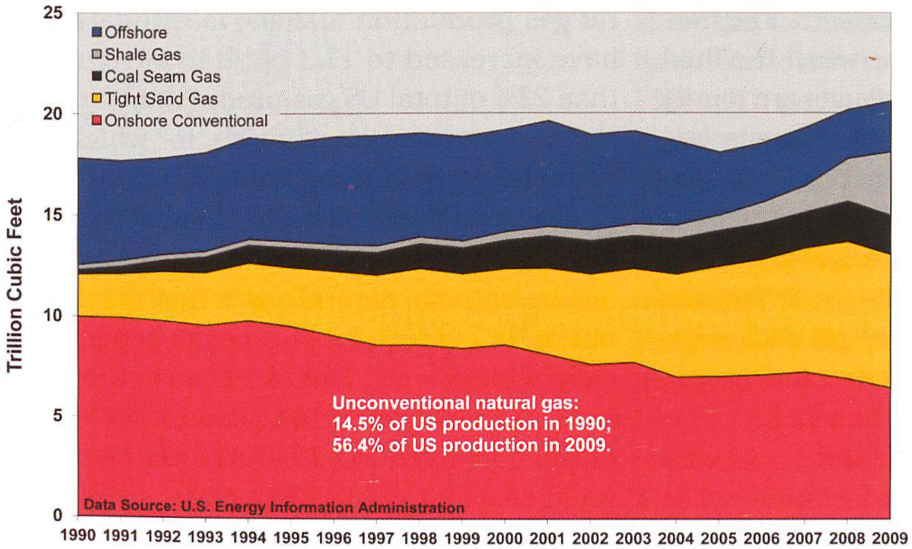

Fig. 12: Growth in unconventional natural gas production in the United States, 1990 – 2009.

wells drilled numbers in tens as opposed to tens of thousands, should therefore be treated with Rogner's «large grain of salt».

Three organisations/companies have recently published estimates for some of the world's recoverable unconventional natural gas resources and these are reported in Table 4.

The table indicates substantial variance for all three types of unconventional natural gas and taken together with the uncertainty that surrounds estimates of shale gas resources even in the highly explored USA, suggests that extreme caution should be used when basing any analysis upon them. The following paragraphs provide just a few thoughts and observations upon each set of estimates.

Advanced Resources International

The Advanced Resources International (ARI) shale gas study was commissioned by the US Energy Information Administration (2011a). It is not all-inclusive but covers 32 of the most prospective countries. Areas with significant potential such as Russia and the Middle East were excluded because their large remaining conventional gas resources mean that shale gas resources are unlikely to be developed in the medium term. ARI summarised the methodology as follows:

1. Conducting preliminary geologic and reservoir characterization of shale basins and formation(s):

Gas In Place (Trillion Cubic Feet) H-H Rogner (1996)	Coal Seam Gas	Tight Gas	Shale Gas	Total Unconventional
North America	3,000	1,375	3,850	8,225
Latin America	50	1,300	2,100	3,450
Europe	275	425	550	1,250
C.I.S.	3,950	900	625	5,475
Middle East / Saharan Africa	0	825	2,550	3,375
Sub-Saharan Africa	50	775	275	1,100
Asia-Pacific	1,725	1,800	6,150	9,675
Total	9,050	7,400	16,100	32,550

Tab. 3: Rogner's 1996 estimate of world in-place unconventional natural gas resources by region and type.

Recoverable Resources (Trillion Cubic Feet)	Year	Coal Seam Gas	Tight Gas	Shale Gas	Total Unconventional
Advanced Resources International	2009	830			
Energy Information Administration / Advanced Resources International	2011			6,622	
International Energy Agency	2009	3,615	2,965	6,440	13,420
International Energy Agency	2011	4,165	2,965	7,200	14,330
Total S.A.	2007		1,600		
Total S.A.	2011	~1,800	~1,350	~4,350	~7,500

Tab. 4: Estimates of world recoverable unconventional natural gas resources by type. Annual world production gas 2010: 112 Tcf.

- Depositional environment of shale (marine versus non-marine)
- Depth (to top and base of shale interval)
- Structure, including major faults
- Gross shale interval
- Organically-rich gross and net shale thickness
- Total organic content (TOC, by wt.)
- Thermal maturity (R_0)

2. Establishing the areal extent of the major shale gas formations.
3. Defining the prospective area for each shale gas formation.
4. Estimating the risked shale gas in-place.
5. Calculating the technically recoverable shale gas resource.

Clearly, much of the detailed information required to make accurate assessments is simply not available in many areas and so the assessments are still relatively speculative. To give two examples which indicate the caution that must be exercised when using the data, the report provides an estimated technically recoverable resource of 41 Tcf for Sweden's Alum Shale, which Shell's recent three wells found to have very limited content of natural gas which it was not possible to produce. On the other hand, the Midland Valley of Scotland, where Europe's first certification of recoverable shale gas resources has taken place, is considered by the report to be non-prospective.
Separately, ARI has estimated world in-place resources of coal seam gas to be in the range of 3,540 to 7,630 Tcf with a recoverable resource of 830 Tcf (Advanced Resources International, 2009). This recoverable estimate for coal seam gas is substantially less than that of the other two organisations.

International Energy Agency

The IEA's 2009 estimates were obtained by taking Rogner's 1996 in-place estimates and applying a 40% recovery factor to each.
The IEA's 2011 estimates still use 40% of Rogner's in-place estimate for tight gas, have increased coal seam gas by 15% (500 Tcf) and upgraded the shale gas estimate on the strength of the US EIA / ARI report. The shale gas value is higher than that of US EIA / ARI, presumably to take account of countries not covered by the report.

Total S.A.

The only major international exploration and production company to have published estimates of in-place and recoverable resources of unconventional gas is French company Total. Total's 2007 tight gas publication estimated the global in-place tight gas resource to be in the range of 11,000 – 18,000 Tcf with 700 – 1,750 Tcf to be recoverable. Total quoted a preferred value at the higher end of the range of 1,600 Tcf recoverable (of which 45% occurred in the US and Canada), presumably reflecting a confidence that technological advances would lead to improved recovery factors.
By 2011 Total had reduced its recoverable tight gas estimate to some 1,350 Tcf, closer to the mid-point of their 2007 range and significantly (55%) less than that of the IEA. Based on their 2007 estimate of in-place tight gas resources, the Total estimate of recoverable tight gas implies a global average recovery factor of around 10%.
The Total 2011 coal seam gas estimate of approximately 1,800 Tcf is 57% lower than that of the IEA but more than twice that of ARI. Given that the reported in-place resources of coal seam gas from around the world only sum up to some 7,000 Tcf, the Total S.A. recoverable coal seam gas estimates may be optimistic.
For shale gas, in 2011 Total estimated that the global in-place potential was in excess of 20,000 Tcf. The company's recoverable estimate of 4,350 Tcf therefore implies a global average recovery factor of some 20%. The Total global recoverable estimate is once again significantly (40%) less than that of the IEA and 35% less than the US EIA / ARI evaluation.

One cannot with confidence say which of these various estimates will ultimately turn out to be more realistic but caution suggests that the more conservative estimate of an E&P company with tight gas, shale gas and coal seam gas assets on six continents may be closer to the truth than applying a 40% recovery factor to a 1996 estimate of in-place resources.

For purposes of comparison, the Total S.A. estimate of 7,500 Tcf of ultimate recoverable unconventional natural gas is volumetrically identical to IHS's end-2009 estimate of remaining recoverable discovered conventional natural gas (Chew 2010), although it also thought that considerable resources of conventional natural gas remain to be discovered, especially in Arctic regions. Also for comparison purposes, the BP Statistical Review of World Energy (2011) estimated proved natural gas reserves (including proved unconventional gas reserves) to be 6,610 Tcf at end-2010.

As a plausibility check one can make the assumption that the relationship between the volumes of ultimately recoverable gas to ultimate recovery of unconventional gas in the US is a good calibration for the rest of the world. Being the world's the most mature country for hydrocarbon exploration, the estimates of ultimately recoverable reserves for the US must be the ones that are the most accurate of any area. There is no reason to assume that the US are a hydrocarbon-geological anomaly and therefore it appears legitimate to extrapolate the US ratio of conventional to unconventional to the rest of the world.

Ultimately recoverable gas volumes for the US amounted at end 2009 to 2,284 Tcf (cumulative production 1,039 Tcf, remaining reserves 193 Tcf, remaining resources 1,052 Tcf). These figures contain, however, the tight gas volumes as well. The ultimately recoverable volumes of unconventional gas (without tight gas) are estimated at 965 Tcf (203 Tcf for coal seam gas and 965 Tcf for shale gas). This implies that the potential of coal gas and shale gas in the US amounts to 42.3% of conventional gas; considering also the tight gas volumes (estimated at a remaining 160 Tcf), unconventional gas reaches about 50% of US conventional volumes. According to IHS the total Ultimate Recovery world expectations for conventional gas were 15,180 Tcf (including reserve growth, yet to find and 3,186 Tcf cumulative past production). When applying the above US ratio of 50% to this figure we arrive at a total unconventional gas potential for the world of 7,590 Tcf; a volume that is in very good agreement with the estimate of 7,500 Tcf by Total S.A. The total ultimately recoverable volume, derived from the above comparison needs, however, to be discounted for the fact that the figure for conventional gas includes both offshore and onshore discoveries. Given the large numbers of wells required, a development of unconventional gas in the offshore at a large scale is unlikely at present energy prices and with the present technology.

8. Impact on the future world energy supply

In the previous chapter we have shown that it is difficult to quantify the exact amount of unconventional gas that will be available to supply the world's energy need of the future. The eventual figure is less controlled by geology - there is a much larger amount of potential geological hydrocarbon resources than assumed a few years ago - but will mainly be determined by the technological progress, the price of alternatives and environmental considerations. The fact is that within less than a decade the new availability of unconventional gas has changed the energy outlook for at least this century and perhaps for the next. While our paper provides a cautious outlook with unconventional gas adding only some 40–50% to the present conventional reserves and resources, there are other estimates that go far beyond this level:

- Hess estimates the total remaining gas reserves and resources at 6,000 BBOE (33,660 Tcf) with $^{2}/_{3}$ of this being unconventional (Drennen 2011).
- Shell estimates the reach of gas reserves and resources (conventional and unconventional) at up to 250 years at present consumption. At the level of the 2010 production of gas this would amount to some 28,000 Tcf gas supply (Lawrence 2011). Shell Chairman Peter Voser quoted the same number in a presentation given in Bern on 1 July 2011 to the Schweizerische Erdöl Vereinigung.
- Texas University studies put the total remaining gas reserves and resources at 22,700 Tcf (Fisher & Tinker 2011).
- CERA (Cambridge Energy Research Associates) estimate after analysis of 49 basins that on a global basis, unconventional gas represents a potentially recoverable resource equal to or even exceeding the conventional gas reserves of the world (CERA Week 2009).

8.1 North America

The US have in the last decade seen the most drastic changes in their already eventful history of hydrocarbon production (BP 2011). A few observations illustrate this:
The US have so far been the textbook example for peak oil and peak gas statistics. However, having reached a first peak of domestic gas production in 1973, the following decline of production could be halted in the late 80's and reversed especially after 2005 to reach a new all-time peak in 2011.
No country has added more gas reserves since 2000. Remaining proven reserves increased by 54% from 2000 to 2010, this in spite of an almost 20% increase in production in the last 5 years.
In 2009 the US had overtaken Russia as the world's No. 1 gas producer.
The root of all these changes is the rapid development of unconventional gas. As of 2010 over 50% of the gas production is unconventional, i. e. it comes from tight gas, coalbed methane (CBM) and now mainly shale gas.
The US are covering almost 90% of their gas needs with domestic production and are well on the way to self-sufficiency. This had a major impact on LNG imports: in 2007 Woodmac forecasted an LNG requirement of 23% of total within 10 years to cover US demand. Presently the LNG demand forecast for the coming 20 years is below 5% (Burri 2010).
The rapid rise of domestic unconventional production has led to a temporary oversupply and a severe erosion of gas prices (Fig. 13). Henry Hub Prices averaged some 7 US$/Mcf between 2002 and 2008, reaching > 13 US$ in mid 2008. Under the impact of the financial crisis and mainly of the rising unconventional production the gas prices collapsed to below 3 US$ and have now stabilized at a low level of 3 - 4 US$ (Late 2011), while crude prices in contrast have fully recovered from the crisis levels.
WTI crude prices were in July 2011 around four times higher on BOE basis than gas (factor 3.5 – 4.4). Gas is presently in the US also some 20 - 30% cheaper than coal, making it highly competitive in the power generation market. This will accelerate substitution, possibly even for transport (Fig. 15).
A negative side-effect of the low gas price is that many unconventional gas projects are no longer economically viable. US shale gas projects require a price between 5 and 8 US$/Mcf (Berman & Pittinger 2011) and several of the small companies may eventually not survive. The low price will, however, trigger corrective mechanisms: lower price implies lower investments and eventually lower production but also lower costs, especially in the still overheated rig market. The extremely competitive price of gas will also accelerate substitution of other, dirtier fuels.

8.2 Europe

Tight gas has been a target especially in the Carboniferous of NW Europe for a long time already, but Europe has only very recently started exploration for shale gas. The old continent has very considerable potential and would be able to cover a substantial part of its gas demand with a production of 5 – 6 Bcf/d as from 2030 (de Viviès, Total, 2011) of which about 50% are expected to come from Poland.

The magnitude and speed of unconventional gas exploration that we have witnessed in the US cannot be extrapolated without modifications to Europe for the following reason:

- Compared to the US the European geology is more small scaled, sweet spots for e.g. shale gas will be smaller and the distribution of suitable sediments more complex.
- European E&P activities are presently geared to the offshore and Europe lacks a

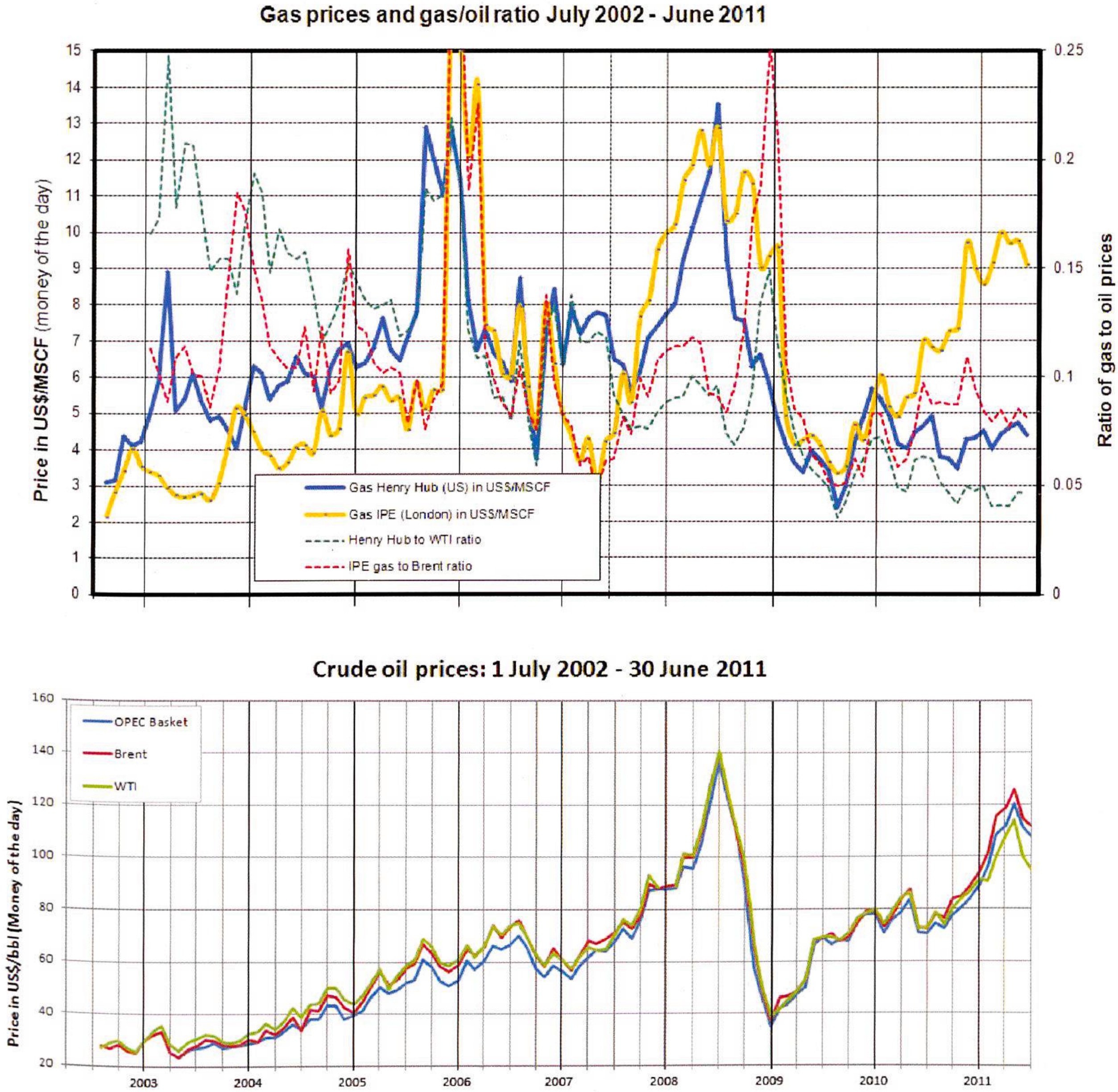

Fig. 13: Development of gas prices in the US (Henry Hub) and Europe (IPE London) and crude prices from 2002 to 2011. Note the relatively good correlation of US and European Gas prices until 2009 and the strong divergence afterwards with gas in Europe costing 2 – 3 times more than in the US; even higher prices (10 – 13 US$/ MSCF are paid in Asian markets). The gas to oil ratios give an impression of the relative value of gas to oil. They show an overall drop of gas price vs. oil price over the last decade (with the exception of an anomaly in 2009). After 2009 gas prices – affected by the unconventional gas bubble – stayed low in contrast to the steeply rising oil prices. Source: Eloi Dolivo. Note: Gas price US (Henry Hub) was 3 US$/ MSCF end 2011.

large, well-established and highly competitive service industry for onshore operations. It has therefore not (yet) the necessary capacity and the competition to guarantee attractive service prices and the ability to supply the needs of large drilling campaigns.

- For shale gas thousands of wells are being drilled in the US plays; in densely populated Europe similar operational scales are difficult to imagine.
- Europe has stricter environmental standards, which drives up drilling costs. The large water use may cause additional environmental hurdles.
- The recent, emotionally motivated moves against shale gas (Moratorium in France and ban in the Swiss Cantons Fribourg and Vaud, protests in Germany) increase the political and economical hurdles for the exploitation of this new domestic energy.

The magnitude of the domestic European supply will depend less on the geological potential but largely on the political will to carry on with exploration in the face of resistance of pressure groups against shale gas. Should several European countries opt out of unconventional gas (similarly to the moratorium imposed in France in mid 2011) the continent would forego an opportunity to diversify its supplies and cement its long-term dependence on Russian and North African pipeline gas (according to the Economist of August 6th 2011, the share of pipeline imports from Russia could fall from presently 27% to 13% by 2040, should the European shale gas reserves be really exploited). The recent decisions (Germany, Switzerland) or intentions of several European countries to exit from nuclear power generation may eventually provide a boost for gas since the proposed change in Energy policy will most likely not be possible without a higher use of coal or gas for power generation. For environmental and cost reasons gas will be the most attractive short-term solution.

Europe is already now indirectly reaping the benefits of the unconventional gas boom in the US. Worldwide LNG production grew by 23% in 2010 and 58% over the past 5 years, largely from new plants, originally built for supplying the future N-American market. With the collapse of the US LNG demand, these volumes have to find new homes in Asia and Europe, resulting in an erosion of prices in Europe (minus 15% in 2011).

8.3 Rest of the world

Unconventional gas is likely to change the future of the world energy supply. According to a forecast of IEA world gas production will have increased by some 50% by 2035, one quarter of this being unconventional gas (IEA 2011). There is no geological reason why tight gas, CBM and shale gas should be more abundant in the US. All areas with rich mature to highly mature source rocks are potential candidates for shale gas production implying that all present major hydrocarbon provinces are in principle attractive for unconventional gas exploration. Among the main gas producing countries only those with additional gas needs (e.g. US, China, Australia) will see a rapid development of unconventional gas in the short term. Countries with cheaply to produce large conventional gas reserves (e.g. Qatar, Algeria and Turkmenistan) will not see any unconventional activities for a long time (Fig. 14). Many additional countries, that have proven rich source rocks but for various reasons only poor or modest conventional exploration results, may join the ranks. While there is thus, in principle, a world-wide potential, unconventional exploration will spread initially in a very uneven way, with main activities in N-America, China, Australia and perhaps a few countries in Latin America and Europe, like Argentina and Poland.

The rise of gas will be controlled largely by the attractiveness of the alternatives, coal, nuclear power and renewables. Coal has been the fastest growing fossil fuel in the last decade, mainly driven by a 130% increase in the last 10 years in China (Economist August 8th 2011), where 1-2 new coal power plants are coming on stream every week. Pollution concerns will curb this growth and the fastest and cheapest way to replace coal power stations is gas, gas power plants being much cheaper and less complex and faster to build than coal fired plants. IEA (2011) foresees for coal a decline as from about 2030. Such an early reversal of the coal trend is, however questionable in the face of huge and cheap coal reserves in China and India and the slowing growth of nuclear after Fukushima. A decline of coal and nuclear cannot be filled immediately by renewable energy even under most optimistic assumptions; gas is at present the only energy that can fill the gap in the short and mid term and only the contribution of unconventional gas can boost gas production to the required volumes.

8.4 Towards a methane economy?

Over the past 25 years global natural gas demand has increased at an average annual rate approaching 4%, 2010 it reached 7%. Several projections show this growth continuing over the next decades and beyond in a possible development towards a global methane driven economy (Fisher & Tinker, 2011). Methane is likely to be the dominant fuel in the global energy mix, representing a bridge in the long term to a non-fossil, possibly hydrogen economy. With or without emission limits and CO_2 control natural gas will continue to grow in power generation where it competes well with coal and nuclear, both economically and environmentally (Fig. 15).

A very large potential for natural gas use is in transportation, although displacing oil is a challenge, given its unique energy density and versatility. A penetration of natural gas in the transport market will therefore probably hinge on the development of an efficient hydrogen fuel cell. The principal raw material for generating hydrogen is natural gas, i. e. hydrogen being produced predominantly through steam reforming of methane. Gas-hydrogen production plants could eventually be coupled with CO_2 sequestration (storing CO_2 in the depleted gas reservoirs).

A development of the world in the direction of a methane economy at the scale envisaged, will only be feasible if very large amounts of natural gas can be brought on stream, possibly requiring a doubling or tripling of the present gas supply. Such sustained high levels of gas production will be possible only with a very major (and in the long term dominant) contribution from unconventional gas. Past experience tells us that there is a very high resource elasticity as our geological knowledge and advances in technology increase and as we learn to do

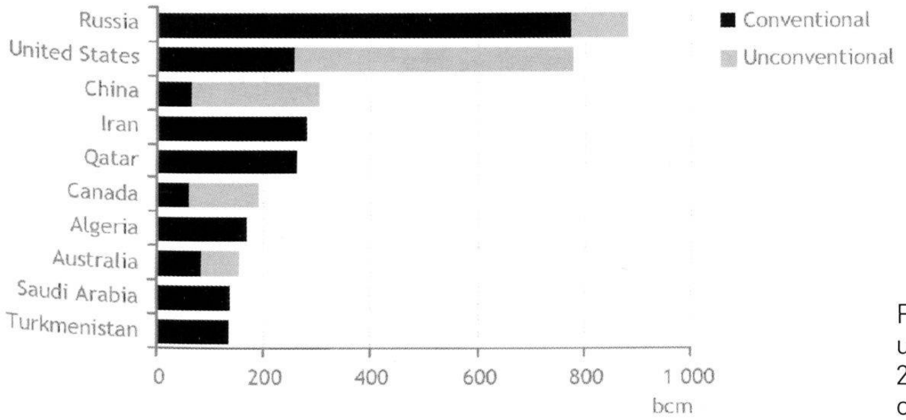

Fig. 14: Forecasted share of unconventional gas production 2035 in main gas producing countries (courtesy IEA 2011).

things better, leaner and cheaper. Given the new dimensions in world gas resources, the initial cost- and technical challenges of unconventional gas are unlikely to constrain such a possible move towards a methane driven world.

9. Summary and conclusions

- **«Unconventional hydrocarbons»** is not an officially sanctioned term but could be described as oil and gas deposits that could so far not be produced economically by traditional oilfield methods. Key enablers for the economical production of unconventional gas are - apart from the world gas and oil price - technological advances, particularly in horizontal drilling and stimulation (hydraulic fracturing). While these technologies have existed for decades, they only started to revolutionize the industry when they became readily available and affordable routine tools.

- **Wastezones**: Hydrocarbon basins are very wasteful systems. In most basins much less than 10% of the hydrocarbons produced and expelled are trapped in the conventional traps that were explored in the past. The remaining, much larger volumes of generated hydrocarbons have either not been expelled from the source rock, have leaked out to surface, or got «stuck in the system», in rocks with poor permeability and thus low producibility. The enormous volumes of «lost» hydrocarbons in these wastezones are now the target for the unconventional oil and gas exploration.
The most important waste zones are the source rocks themselves. Recent studies indicate that only between 5 to 35% of the hydrocarbons produced may eventually

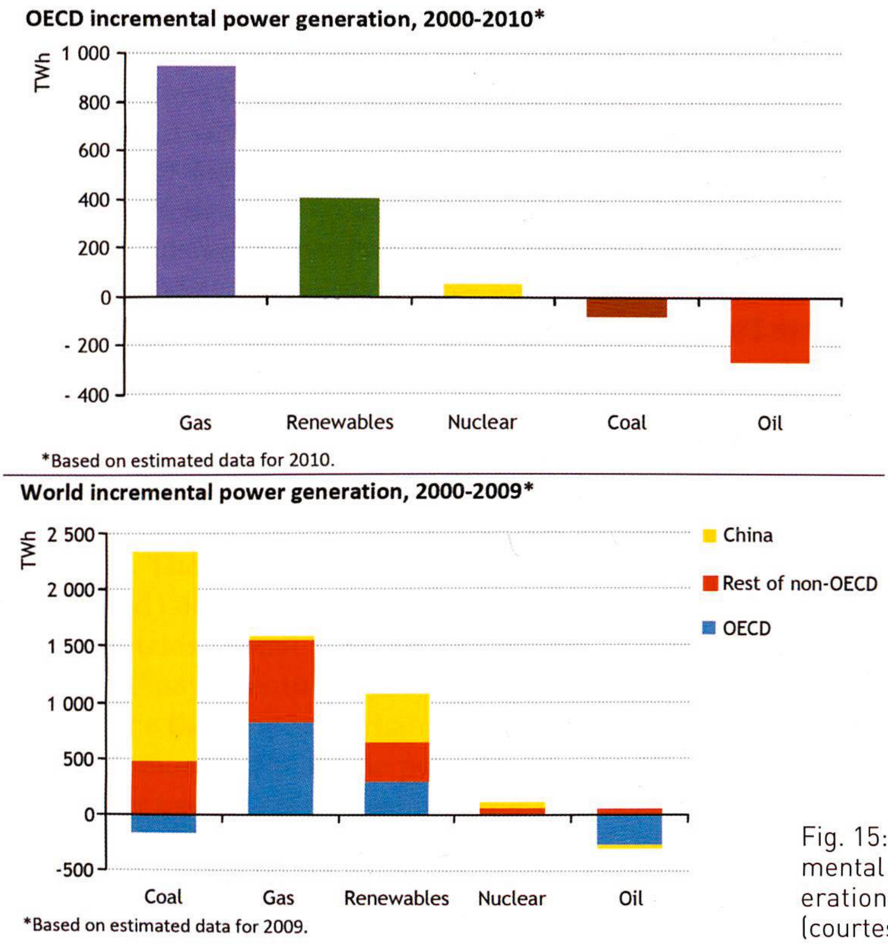

Fig. 15: Gas in power generation. Incremental changes for fuels in power generation: OECD and world, past decade (courtesy IEA, 2011).

leave the source rock. Gas shales are source rock, reservoir and trap in one. A prerequisite to unlocking this potential is a high TOC (> 2%), a high maturity and brittleness to allow hydraulic fracturing, i. e. the rocks require a significant quartz or carbonate content.

- **Unconventional activities in Europe** are focused primarily on gas. Due to the smaller scaled geology, higher population density, stricter environmental regulations and a not highly developed onshore service industry, the unconventional gas boom of the US cannot be duplicated in the same explosive way in Europe. While Europe has considerable potential even in countries with no present gas production (e.g. Switzerland) the development will be much slower and requires a considerable effort to inform and educate a critical public and politicians who have little or no knowledge of the oil and gas industry.
  - *Coal seam gas*: European coal seam gas resources are estimated at 300 Tcf of which, however, only a small part can be recovered (estimated at some 50 – 60 Tcf). Significant production exists so far only in the UK.
  - *Tight gas*: Tight reservoirs have permeabilities of < 1 mD. Tight gas has been a target in many European countries for decades, especially in the Permian and Carboniferous of NW Europe. Tight gas in place for Europe is estimated at > 1000 Tcf of which some 100 – 200 Tcf may be recoverable.
  - *Shale Gas*: Prime targets in Europe are the Lower Palaeozoic, the Carboniferous and the Liassic. Interestingly, no post-Mesozoic shale gas plays are known. Some initial gas production has so far only been achieved in UK and Poland. Recoverable resources for unconventional gas in Europe could reach > 500 Tcf (in place estimates range from 2,000 to > 5,000 Tcf).

- **Russian activities**: Russia holds almost a quarter of the world's conventional gas reserves. It has therefore also an abundance of world-class source rocks and thus a very high potential for shale gas. However, given the magnitude of conventional gas supply, Russia's need to explore for shale gas may be several decades away. Present estimates of shale gas resources amount only to 18 Tcm but must be far greater, at least by an order of magnitude, given the overall gas richness of the country. More attention is currently paid to coal seam gas with estimated recoverable resources of 112 Tcm, a large part in the Kuznetsk Basin in SW Siberia.

- **International unconventional activities**: Exploitation of Coal-seam Gas (Coalbed Methane) has reached a mature state in many countries outside N-America with high activities particularly in China and Australia, where the first LNG plant fed by coal gas is being completed. All countries with hard coal resources (bituminous rank or above) have the potential to produce coal seam gas.
  The US, with high exploration activities in the past decade, have total remaining unconventional gas resources of > 1,125 Tcf (recoverable); at end 2010 total remaining conventional gas reserves stood at 272 Tcf. Since 2008 unconventional gas production covers > 50% of the total US gas produced and its share is rapidly rising. Outside the US, shale gas activities are only in a state of early exploration and trial production; rapid development is foreseen in Australia, China, India and possibly Argentina.

- **Technology**: the main tools for unconventional gas development are high resolution seismic, horizontal drilling and stimulation (generally multi fracturing of the sediments). These methods are not new: horizontal drilling has been practiced widely since the late 80's and simple hydraulic fracturing has been applied for over 50 years. In N-Germany horizontal drilling and multifracs in tight Permian reservoirs are successfully applied since the early 90's. The use of such techniques in ten thousands of unconventional gas wells in N-America has, however, led to major technical improvements and has transformed these frontier technologies into affordable routine tools.

- **Possible environmental risks with the development of shale gas**: Unconventional gas development, especially shale gas has come under attack by environmental groups in Europe, for alleged pollution of groundwater, high water use and the risk of induced seismicity. A close scrutiny of the claims shows that the occasional problems observed in shale gas operations are challenges, known also from drilling and stimulation in conventional gas developments. It will, however, be necessary to establish clear, compulsory standards for drilling, stimulation and completion and an obligation to disclose the composition of drilling and fracture fluids. Main concerns are:
  - *Fracturing to surface*: Fracturing of shale gas reservoirs takes generally place at depths between 1,500–2,500 m, often at much greater depths. Seismic monitoring of the fracturing shows that the fractures have a limited vertical extension (decreasing with diminishing overburden) and do not connect to surface or to utilized aquifers. The known cases of fracture fluids or gas leaking into surface aquifers can be attributed to poor cementation of casing or deficient well integrity. The 2011 UK House of Commons Energy and Global Warming Committee comes after extensive studies to the conclusion that: «... hydraulic fracturing itself does not pose a direct risk to water aquifers».
  - *Induced seismicity*: Any fracturing of rocks creates an acoustic signal, i.e. a small seismic event. This is a normal and desirable phenomenon that allows (with microseismic monitoring) to determine the exact location and extent of the created fractures. Hydraulic fracturing in sediments is associated with much smaller induced seismicity than e.g. in crystalline rocks, much of the energy being absorbed in ductile sediments. From the several ten thousand shale gas wells that have been fracture-stimulated worldwide no case is known with an induced seismicity of a magnitude that can cause damage.
  - *Toxicity of fracturing fluids*: Toxic additives to the frac fluids are a concern. The additives are supposed to produce better and more durable permeability in the stimulated rocks. The necessity for an extensive use of additives can be questioned, e.g. a very large fracturing job in the geothermal well Basel-1 was carried out with river water without additives. Disclosure of the additives by the service companies is a must as a first step to public acceptance. The concern about contaminated flow back fluids can be mitigated through recycling, purification or reinjection of the used water into the reservoir.
  - *Water consumption*: with an average of 13,000 m^3 of water used for each shale gas well and large numbers of wells, water consumption is a concern. Water use footprints, calculated per unit of energy (MWh) produced, show, however, that unconventional gas consumes only about 1/20th of the water used in coal power plants or 1/30th of the water used in nuclear plants to produce 1 MWh, The most water intensive energy is Biomass.

- **Global potential of unconventional gas resources**: Except for coal seam gas, large-scale development of unconvention-

al gas, especially shale gas, has reached maturity only in N-America. Estimations of the global potential of unconventional gas resources need therefore to be taken with a large grain of salt.
In 2009 unconventional gas covered 54% of all US production and 12% of world gas production, a share that is rapidly rising. A comparison of ultimately recoverable conventional and unconventional gas resources for the US shows that unconventional gas could reach up to 50% of conventional resources. An extrapolation of this ratio to the entire world indicates that some 7,500 Tcf of unconventional gas could be recovered globally.
This figure could nevertheless be conservative, since estimates have been rising annually, driven by technology and energy prices. Against all predictions by the peak gas theory, the total proven world gas reserves for conventional gas have been increasing by 50% between 1990 and 2010; in the exploration-wise very mature US, proven gas reserves have increased even by 60% in the same period.

- **Impact on future world energy supply**: The above estimate translates into remaining total global gas resources of about 19,500 Tcf (12,000 conventional and 7,500 unconventional). Many other estimates (e.g. Texas University, Shell and Hess) are between 15 and 60% higher. CERA (Cambridge Energy Research Associates) assume that unconventional gas resources are equal to or exceeding conventional volumes. At the level of the 2010 global gas production of 112 Tcf/y these estimates translate into a global gas reach, ranging from 170 to 300 years of supply.
  In N-America the rise of the unconventional gas has led to a collapse of LNG imports and to a steep fall in gas prices, now 20-30% lower than coal and 4× lower than oil by energy equivalent. The North American gas surplus has started to depress gas prices around the world. It is leading to more LNG spot trading and thus to the start of a truly global gas market that is freeing itself from the previous oil indexation.
  Unconventional gas will dramatically change the energy outlook and the energy mix of the world, initially mainly in Asia, later worldwide. Given the possibility that world natural gas resources could last for centuries, rather than decades, gas is the ideal fuel to provide the bridge to a future, since renewables will for the mid-term not be able cover the world energy growth, let alone replace nuclear and coal (e.g. the 2010 increase of total power consumption in Switzerland was 50× larger than the country's total produced solar energy).
  Natural gas is today the main source of hydrogen production; the transition world could therefore well be a methane economy, driven by gas-supplied hydrogen fuel cells that would also power our mobility. Depleted gas fields could be used for CO_2 sequestration.

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Acronyms

B: Billion (10^9); BOE: Barrel Oil Equivalent; BBL: Barrel; Bcf: Billion Cubic Feet (10^9); Bcm: Billion Cubic Metres; CBM: Coalbed Methane; Cf/d: Cubic Feet per day; Cf by wt: Cubic Feet by weight; CSG: Coal Seam Gas; EIA: US Energy Information Agency; EUR: Estimated Ultimate Recovery; E&P: Exploration and Production (of oil and gas); ft: feet; HC: Hydrocarbons; IEA: International Energy Agency; Industry: here the oil and gas industry; LNG: Liquid Natural Gas; M: Thousand; mD: milli-Darcy; MM: Million; MPa: Mega Pascal; psi: pounds per square inch; scf/ton: square cubic feet / ton; Tcf: Trillion Cubic Feet (10^{12}); Tcm: Trillion Cubic Metres; TOC: Total Organic Carbon; TWh: Tera Watt hours (10^{12}); SR: Source Rock; VR: Vitrinite reflectance; wt %: weight percent; 2P: probable reserves; 3D: Three dimensional seismic.
Conversion: 1 Tcf = 28 Bcm, 1 Tcf ≈ 177 million BOE.