Oxford Review of Economic Policy, Volume 27, Number 1, 2011, pp. 117–143

Shale gas—the unfolding story

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Abstract In the early 2000s US gas production was in slow but steady decline despite increasing drilling activity. As US natural gas prices rose in response to the resulting tight market, the only supply-side solution appeared to lie in the development of liquefied natural gas (LNG) projects in the Middle East and Africa for importation to the North American market. Almost unnoticed in its early stages, the US shale gas phenomenon gathered momentum from 2004 onwards through the combination and application of two proven technologies, namely horizontal drilling and pressure-induced hydraulic fracturing or 'fracking'. The pioneers of this approach were not the majors but the much smaller, domestically focused 'independent' upstream companies who, together with a well-established and adaptable service sector, instigated what is now commonly referred to as the 'shale gas boom' and which has increased US natural gas production to the point where only minimal imports of LNG are expected to be required for the foreseeable future. This paper looks at the genesis of the US shale gas industry, the intensive nature of its operations, and the factors which have underpinned its success to date. It also addresses the question of whether similar developments might be expected in Europe and what specific challenges would need to be overcome. In a world where increased LNG supply has created trade flow and price linkages between regional gas markets, the paper also examines the impact US shale production has had on other markets through the re-direction of LNG originally intended for the US market.

Key words: natural gas, shale gas, unconventional gas

JEL classification: Q410

I. Introduction and context

Over the past 3 years unconventional gas has moved from a minority interest to centre-stage focus in natural gas circles. This has been driven by the largely unforeseen growth in North American shale gas production, which in 2006 effected a reversal of the decline in total US natural gas production.

Estimates of global unconventional gas resources have, since the late 1990s, exceeded those of conventional gas. However, doubts as to their viability at prevailing natural gas market prices served to limit the expectation of future production from these sources. In the US in the mid-2000s, however, the application of technology transformed shale gas development into a key oil and gas industry growth sector. This has radically changed perceptions of gas supply availability in the US and elsewhere. This mood is captured in

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doi: 10.1093/oxrep/grr004

a recent *New Scientist* article (Knight, 2010): ‘New technology to extract natural gas from what’s called ‘‘unconventional’’ deposits means previous gas-poor countries in the Americas, Asia and western Europe could have enough cheap gas to last for another 100 years at present rates of consumption.’

As we entered the 2000s the prevailing view of gas as a cheap and plentiful energy source changed to one of concern over the ability of gas supplies to keep pace with future rising demand, particularly in the power generation sector. In North America, in 2001 domestic production began a pronounced decline and large-scale liquefied natural gas (LNG) imports appeared inevitable by 2010. In Europe, with domestic production in long-term decline, increased reliance on Russian pipeline gas imports and the need to compete for future LNG supplies in a global market, raised security-of-supply concerns, exacerbated by the long-running Russia–Ukraine transit issues. In Asia the unforeseen decline in Indonesia’s LNG export performance from existing plant, together with Japan’s nuclear reliability issues and the imminent emergence of China and India as LNG importers, also created the expectation of a ‘tight’ market for gas in the years ahead.

Conventional gas resources are concentrated in Russia and the Middle East region (24 and 41 per cent, respectively, of global proven reserves).[1] However, with the notable exception of Qatar, the outlook for significant additional Middle East exports, whether of pipeline gas or LNG, appears muted.[2] This is largely a consequence of high population growth and policies for low domestic market gas prices which have resulted in burgeoning domestic gas demand growth and reduced incentives for developing new, higher-cost reserves. The potential for additional export volumes of conventional gas from this region to the markets of Europe, North America, and Asia is, therefore, likely to be limited.

The 2000s view of gas as a fuel with uncertain supply availability and, especially in the case of the US and Europe, high import exposure and security-of-supply issues may have been instrumental in its inability to find a constructive role in climate change abatement policy to date, other than being consigned, by default, to the ‘fossil fuel’ category of undesirable energy forms. With the new-found optimism surrounding unconventional gas in general and shale gas in particular, the prospect of new sources of domestic production, reducing import requirements and enhancing security of supply, comes at a timely point in the evolving climate change debate.

Recession-hit economies may begin to ponder the cost to the consumer of the ‘dash for wind power’ (with Spain already announcing steep cuts for wind and solar subsidies), and the realism of achieving the financing and timely installation of wind capacity sufficient to meet the 2020 European carbon dioxide (CO_2) reduction targets must be open to question. Gas has half the CO_2 emissions of coal per kilowatt of power generated, and already, in the US, the enhanced role of natural gas as a ‘bridge’ fuel to a low carbon future is under consideration, both as a means of flexible power generation (to respond to high and low periods of wind generation) and as a potential transportation fuel and as compressed natural gas (CNG).

Realizing such a change in the fortunes of natural gas is, however, conditional on two key premises: (*a*) that the growth in shale gas production in the US is sufficient to offset production decline in other categories of gas production and keep pace with demand; and (*b*) that the shale gas resources of Europe and elsewhere can be developed economically at prevailing natural gas prices. At present neither is a foregone conclusion.

[1] BP (2010*a*).
[2] Fattouh and Stern (2011, pp. 547–53).

Section II contains a brief literature review. Section III briefly characterizes conventional and unconventional gas and examines the global distribution of unconventional gas resources, but cautions regarding the distinction between estimated resources in place and what ultimately might be developed. This section charts the recent dramatic growth in US shale gas production within the context of a rising gas price environment in the early to mid-2000s followed by a price slump in 2009. Section IV examines the nature of the development of the Barnett shale play in the US in more detail, including the intensive nature of the drilling and fracturing operations. The scale of subsequent North America shale plays is noted, together with future production projections by play. This section, having noted many of the factors which assisted in the development of the Barnett shale concludes by examining factors which might limit the future growth of shale gas production in the US. A framework is developed by which the likely growth in shale gas production in other regions, such as Europe, might be evaluated. Section V examines the impact that US shale has already had in other regional natural gas markets through the re-direction of some of the significant recent growth in LNG supply at a time of weaker gas demand as a consequence of the recession. Section VI looks at the potential for shale gas in Europe, the challenges it would have to overcome, and the scale of activity required materially to reduce Europe's natural gas import requirements. Section VII concludes the paper.

II. Literature review

Existing literature on shale gas and unconventional gas in general tends to fall into three categories: sources focusing on gas resource assessment and energy policy implications; the more 'real time' papers and articles issued by the industrial practitioners of shale gas exploitation and entities directly involved in its development; and, lastly, the more arm's length commentators for whom the unforeseen nature of US shale gas production, its rapid growth, and the apparent scale of the resource provides a compelling storyline.

The International Energy Agency, in its *World Energy Outlook 2009*, provides a useful summary of the relevant issues surrounding unconventional and particularly shale gas (IEA, 2009, pp. 389–416). The chapter devoted to 'Gas Resources, Technology and Production Profiles' places global resource estimates of unconventional gas in the context of conventional gas estimates, reviews the historic growth of US unconventional gas, and examines the dynamics of shale gas development and the potential for shale gas development outside the US. This source represents essentially an overview of the state of play as at the end of 2008.

The 2007 Topic Paper, 'Unconventional Gas', by the National Petroleum Council (NPC, 2007) assesses global unconventional gas resources and reviews the technological aspects of US shale gas production and the critical role of new technology and research and development in sustaining North American gas production.

ALL Consulting (ALL, 2008) provides an informative overview of US shale gas developments which includes a projection of unconventional gas production to 2018. Medlock (2009) provides detailed forecasts of future US and Canadian shale gas production by play to 2030 and incorporates this in a global modelling framework to demonstrate the reduced future US LNG import requirements.

MIT (2010) and Brown *et al.* (2010) are both papers which set out to quantify the impact of higher domestic natural gas availability (due primarily to shale gas) on the future US energy mix. The broad conclusions are that gas should continue to increase its share of the energy mix at the expense of coal for the foreseeable future and, in the absence of an explicit cap-and-trade mechanism for CO_2 abatement, would be more competitive than high-cost renewable energy sources. Even with the introduction of a cap-and-trade system, gas consumption growth is expected to increase between 2010 and 2030.

Papers and articles from industry practitioners and entities involved in shale gas development are particularly useful in informing certain aspects of the shale gas phenomenon, given the rapid pace of its development. These include those published on the web by Schlumberger, Rigzone, and others, which are referred to in the text of this paper.

In general, the literature tends to focus very much on the scale of the global resource of unconventional gas and generate reassuring estimates of 'recoverable gas' by applying a uniform recovery factor. The US shale gas experience is recounted in detail and, in some cases, this is incorporated into a future projection of US or North American supply and demand.

Less clear from the literature are the critical assumptions on which US non-shale gas production is based and the impact which LNG arbitrage would have in transmitting prices between Europe and North America and thus accelerating or decelerating US shale gas development.

Such a model would be highly complex and its results highly dependent upon key assumptions which are subject to high levels of uncertainty. This, however, is likely to be the future reality. Rather than attempting to quantify such future trends, this paper seeks rather to identify the key factors which will help or hinder shale gas growth in the US and Europe.

III. Gas—conventional and unconventional

(i) The origin of natural gas

Oil and gas originated from the remains of pre-historic zooplankton and algal blooms which thrived in lake bottom or river delta environments. Over geological time their remains were buried with and beneath layers of sediment. As the depth of burial increased, so did temperatures and pressures transforming the sediment surrounding the organic material into shale. This process caused the organic matter to change, first into a waxy material known as kerogen and then, with more heat, into liquid and gaseous hydrocarbons.

The rock strata in which the kerogen was formed and transformed into oil or gas are known as a 'source rock'. The oil and gas tended to migrate upwards through pores and faults in overlying rock strata, ultimately reaching the earth's surface or alternatively becoming trapped within porous rocks (known as reservoirs) by impermeable rock strata above them. The process of oil and gas migration is influenced by underground water flows, causing oil and gas to migrate hundreds of kilometres horizontally or even short distances vertically before becoming trapped in a reservoir.

Gas, in the 'conventional' sense, remains in these reservoirs as *non-associated gas* where there is no oil present, as *associated gas* where it is dissolved within oil in an oil-filled reservoir, or, lastly, as *gas-cap gas* where there is a distinct gas layer above an oil layer within a reservoir. In all three cases, the hydrocarbons are produced by drilling wells from the surface into the reservoir where the pressure drive of the underlying water aquifer, combined with the action of re-injecting water or a portion of the produced gas, maintains well flow rates. At the surface the hydrocarbons are processed into separate streams of oil, condensate, natural gas liquids (ethane, propane, and butane), and natural gas (mainly methane).

The above description helps us to understand the differing characteristics of the three categories of 'unconventional gas' which are the subjects of this paper, namely tight gas, shale gas, and coal bed methane (CBM).

Tight gas essentially refers to a non-associated gas reservoir which has a much lower porosity/permeability than is usual for gas sandstone reservoirs. A working definition might be a natural gas reservoir that cannot be developed profitably with conventional vertical wells, owing to low flow rates (IEA, 2009, p. 398). In addition it may have low vertical permeability because of thin horizontal layers of non-permeable rock.

Shale gas is natural gas which failed to escape its original shale source rock owing to a lack of a viable migration path. The shale itself has very low permeability and, without employing fracturing technology, production well flow rates would be minimal. Gas can be stored in the shale by different mechanisms: within the pores of the rock, within naturally occurring fractures, or adsorbed on to the shale minerals and organic matter within the shale. Releasing the gas from the shale in commercial quantities requires hydraulic fracturing to create large areas of exposed rock surface from which the gas can flow (IEA, 2009, p. 400).

CBM is natural gas contained in coal deposits. The gas is usually produced from coal which is either too deep or of too poor a quality to be mined commercially. The methane lines the inside of pores within the coal (called the matrix). The open fractures in the coal (called the cleats) can also contain free gas or can be saturated with water. When the reservoir is put into production, water in the fracture spaces is pumped off first. This leads to a reduction of pressure enhancing desorption of gas from the matrix.

In order to produce natural gas in commercially viable quantities, all three categories of unconventional gas require different drilling and production technologies compared with gas in a conventional reservoir.

(ii) The scale of global unconventional gas resources

In its 2009 *World Energy Outlook*, the IEA opines that, while the scale of recoverable unconventional resources worldwide is thought to be very large, they are currently poorly quantified and mapped, including in the USA where despite significant effort, large uncertainties remain. Detailed estimates of unconventional gas resources outside of North America tend to be limited to areas either under development or the subject of exploration and appraisal. The IEA illustrates the distribution of global unconventional gas resources in Table 1.

After factoring in a plausible estimate of recoverable portions of unconventional gas in place, the IEA estimates remaining recoverable unconventional gas resources to amount to some 380 Tcm. This is equivalent to 125 years of current global natural gas consumption and is in addition to the IEA's estimate of remaining recoverable conventional gas reserves of 405 Tcm.

While North America currently produces tight gas, shale gas, and CBM, production is limited elsewhere in the world. While data on tight gas seem not to be generally available, some data on international CBM production can be found. In Germany, exploration for CBM in the 1990s by Ruhrgas and ConocoPhillips was unable to identify commercial resources at the then low gas prices. However, there is renewed interest in German CBM prospects (Mösle *et al.*, 2009). Elsewhere the interest in Europe is chiefly focused on prospective shale

Table 1: Global unconventional natural gas resources in place (trillion cubic metres—Tcm)

	Tight gas	Coalbed methane	Shale gas	Total
Middle East and North Africa	23	0	72	95
Sub-Saharan Africa	22	1	8	31
Former Soviet Union	25	112	18	155
Asia-Pacific	51	49	174	274
Central Asia and China	10	34	100	144
OECD Pacific	20	13	65	99
South Asia	6	1	0	7
Other Asia-Pacific	16	0	9	24
North America	39	85	109	233
Latin America	37	1	60	98
Europe	12	8	16	35
Central and Eastern Europe	2	3	1	7
Western Europe	10	4	14	29
World	**210**	**256**	**456**	**921**

Source: IEA (2009, p. 397).

gas development (see section VI). In Australia CBM has supplied the domestic market since 1987 with 2005 CBM production at 1.5 billion cubic metres per annum (bcma). At least one CBM-fed LNG project is expected to proceed by 2015. CBM in China started in 1992 and is expected to be 10 bcma in 2010. India produced less than 0.1 bcma in 2009 (ICF, 2010).

While the scale of the global estimate of unconventional gas resources is reassuring, it should be viewed in the context of the uncertainties and challenges associated with converting this (largely as yet undiscovered) resource into a competitively priced supply at the burner tip. These challenges may be grouped under the following headings:

- *geological risk*: confirming the presence, extent, and favourable characteristics of unconventional gas in a specific location;
- *technology and viability risk*: determining whether a specific deposit can be developed on an economically viable basis at the prevailing market gas price by the application of technology;
- *regulatory and public acceptance risk*: this relates to risks that the regulatory structure is conducive to unconventional gas exploitation and that such exploitation is acceptable to the local population.

This paper examines the US shale gas experience under such headings and uses this as a framework to assess the challenges facing shale gas development in Europe.

Although the estimates for unconventional gas resources are on a par with those of conventional gas, the challenges associated with their development are significant and in some cases these will likely preclude exploitation of gas reserves in significant quantities.

The US provides a useful case study in gaining an understanding of how such risks have been addressed and largely overcome, and also provides a framework to assess the nature of the challenge faced by developers of unconventional gas in other regions, such as Europe.

(iii) US gas production and unconventional gas in the US supply mix

In this section the US gas production environment and the growth of unconventional gas is described in two periods. The first period from 2000 to 2008 was characterized by falling conventional production and rising prices—an environment which was conducive to the development of shale gas. The period 2008–10 has been one of falling gas price and rig count but, remarkably, robust production.

US gas production to 2008

Figure 1 illustrates the contribution to US domestic natural gas production from shale gas, CBM, and tight gas, for the period 1990–2008.

Over this period unconventional gas's share of domestic production grew from 15 per cent to 51 per cent. The largest unconventional gas contribution is from tight gas, while the fastest growing sector in percentage terms is shale gas, whose post-2005 rapid growth phase is clear in Figure 1.

Through the 1990s, while US natural gas prices remained (by comparison with today's levels) low—in the range of \$1.50–\$2.80/million British thermal units (mmbtu), shale gas production remained broadly flat, while CBM and tight gas production in aggregate doubled between 1990 and 2000. Production of unconventional gas in the US benefited from the Alternative Fuel Production tax credit contained in the Crude Oil Windfall Profit Tax Act of 1980. The tax credit was \$0.50/million cubic feet (mcf) of unconventional gas production (for context, the Henry Hub gas price for 1989 was only \$1.75/mcf) (BP, 2010*b*). Its scope of application for natural gas was confined to tight gas, CBM, and Devonian shale gas (EIA, 2000). Nevertheless activity accelerated in the Antrim shale in the Michigan basin, the New Albany shale in Illinois, and the Barnett shale in the Fort Worth basin, Texas. The tax credit expired for production from wells drilled after 1992 (Geny, 2010).

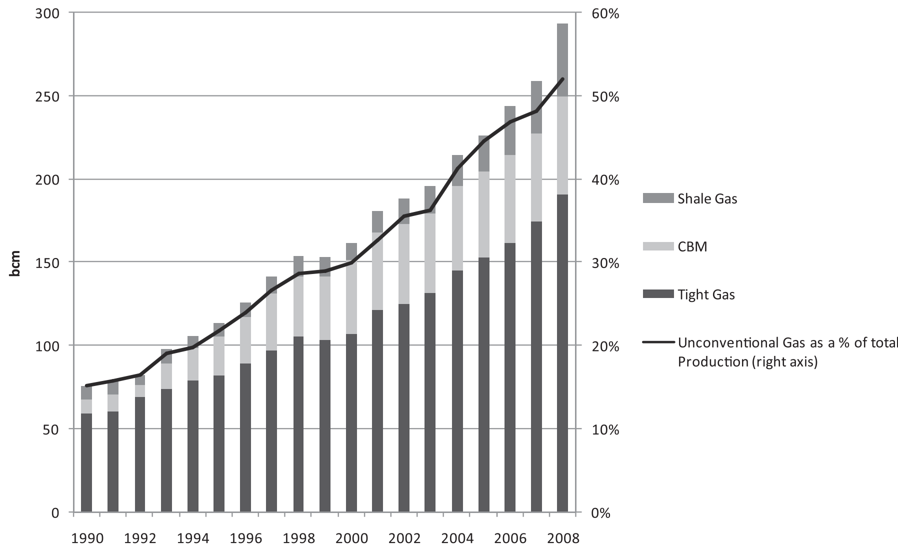
As we entered the 2000s US natural gas production began a noticeable decline trend of around 1.4 per cent per year, despite an increase in the number of rigs targeting new gas supplies. Tighter supply inevitably resulted in higher natural gas prices, frequently tracking fuel oil prices (through inter-fuel competition in the power generation sector), with event-driven high price excursions caused by cold weather spells and hurricanes, often taking gas prices up to and sometimes exceeding gasoil levels.

The more buoyant gas price environment of the early 2000s and the flagging productivity of conventional US gas production in this period provided a strong stimulus to innovative approaches to unconventional gas through new technological applications. In 2005 in the Barnett shale, operators deployed two technologies, with individual proved track records, in a novel combination, namely *horizontal drilling* and *hydraulic fracturing* (Geny, 2010). The subsequent refinement of this approach, including multi-stage fracking, multi-bore drilling from the same location, and the experimentation with the chemical formulation of the water-based fracking fluid, lies behind the sudden rapid growth in shale gas production post-2005—on a scale which reversed what seemed at the time an inevitable continuing decline in aggregate US gas production. Such an outcome was unforeseen by the majority of market observers—not least the oil and gas majors who had re-focused their efforts in the early 2000s on developing LNG supply projects, a significant portion of which was tagged for the US market.

It is important to note at this juncture that, since 2005, tight gas, CBM, and shale gas have begun to follow diverging growth paths. Tight gas represents around a third of total US gas production (see Figure 1), but well productivities have halved in the decade since 1996 (Figure 3).

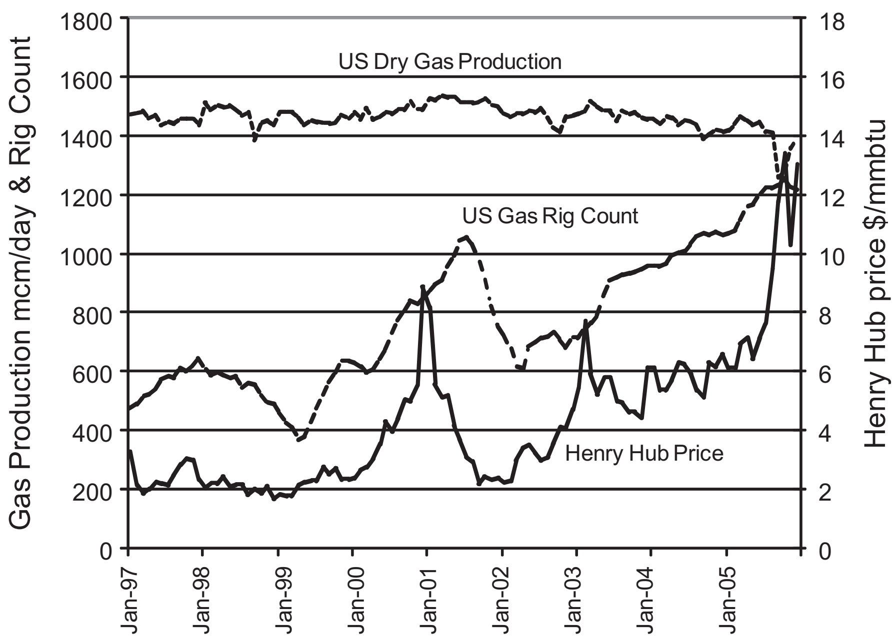
Florence Geny (2010) mentions that, for two of the most prolific tight gas sands in the US (Pinedale and Jonah (Wyoming)), there is evidence from 2,300 wells indicating that the two

Figure 1: Production of unconventional gas in the United States



Source: IEA (2009, p. 398).

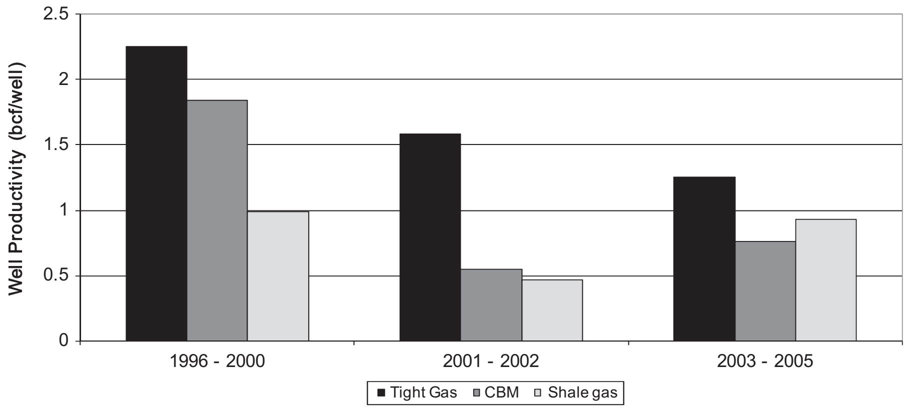
Figure 2: US gas production, gas rig count, and Henry Hub price, 1997–2005



Sources: EIA, Baker Hughes.

plays have seen declining well productivity since 2007 and 2009, respectively. She posits that the rise in production costs consequent upon this productivity decline will re-focus drilling activity away from tight gas and towards shale gas plays, as she states is the case in

Figure 3: Changes in unconventional gas well productivity, 1996–2005



Source: Kuuskraa (2007).

the Piceance, Uinta, and Green River Basins. This remains something of a grey area, however. Certainly this view is supported by the IEA (2009, p. 399). However, while shale gas has been the main focus of unconventional gas literature and media attention, companies such as Shell, Exxon, and BP are in the process of expanding their position in US tight gas, using horizontal drilling and fracturing approaches to enhance well production levels. Tight gas may yet make a growing contribution to total US gas production.

CBM production grew from the late 1980s, reaching a plateau in 2004 at 1.8 trillion cubic feet per year, some 9 per cent of total US production. As in the case of tight sands, CBM well productivity is in decline (Geny, 2010). While CBM reserves have continued to grow, it would seem unlikely that we are about to embark on a phase of rapid production growth from this source while shale gas, and perhaps also tight gas, activity appears to dominate the upstream mindset.

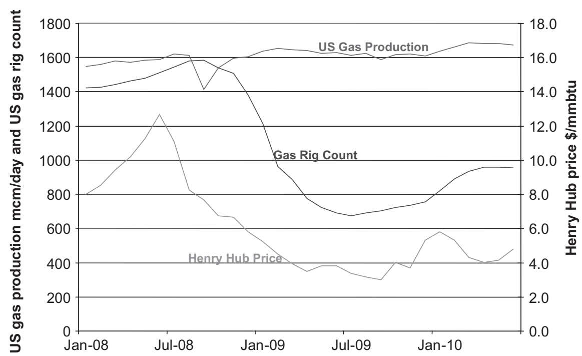
US production to 2010

The onset of the global recession in the second half of 2008 saw a pronounced fall in the US natural gas price and a corresponding reduction in the number of rigs actively drilling for gas (the gas rig count). By mid-2009 the gas rig count had fallen some 60 per cent from the level of September 2008. The widely anticipated reduction in US natural production, however, failed to materialize, as is demonstrated in Figure 4. On the contrary, gas production, according to Energy Information Administration (EIA) statistics, actually increased from the end of 2009 to June 2010. Gas rig count also staged a partial recovery in this period. Although comprehensive data are not publicly available, it is highly likely that a decline in more marginal conventional production in this time period has been more than offset by increased unconventional gas production.

Figure 5 illustrates the growth in rigs capable of horizontal drilling over the 2003 to 2010 period. Horizontally drilling rigs (used for both shale and tight gas) saw only a more modest reduction in 2009 compared to vertically drilling rigs, and this had recovered by early 2010 to levels which exceeded those of 2008. This supports the hypothesis that the gas price fall of 2009 focused drilling efforts away from conventional gas towards shale and also, potentially, tight gas.

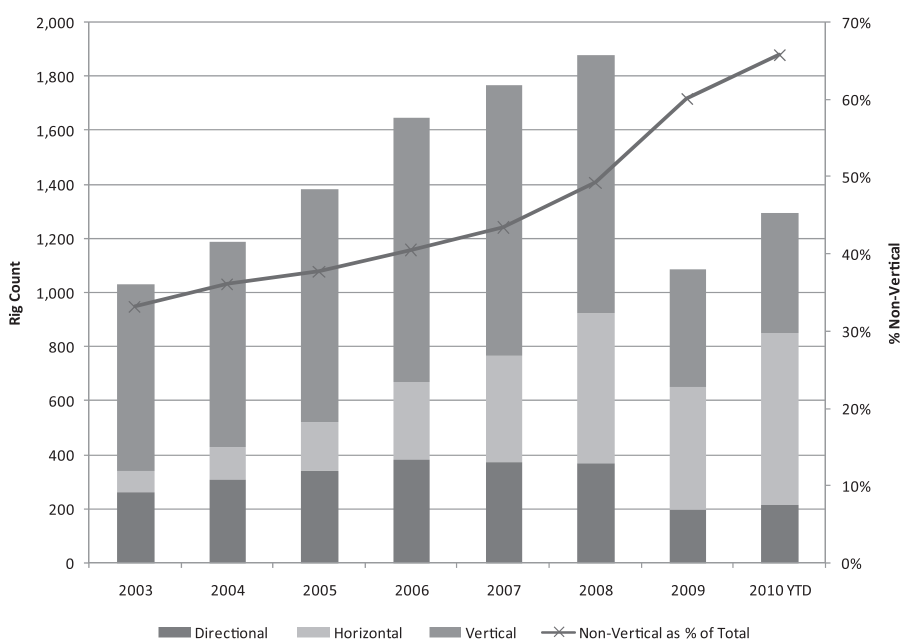
Although 2009, owing to low gas prices, was a difficult time for gas producers, the more innovative operators 'sold production forward', taking advantage of the traded market's

Figure 4: US natural gas production, gas rig count, and Henry Hub price, January 2008–June 2010



Source: EIA, Baker Hughes.

Figure 5: US rig count by drilling type, 2003–10

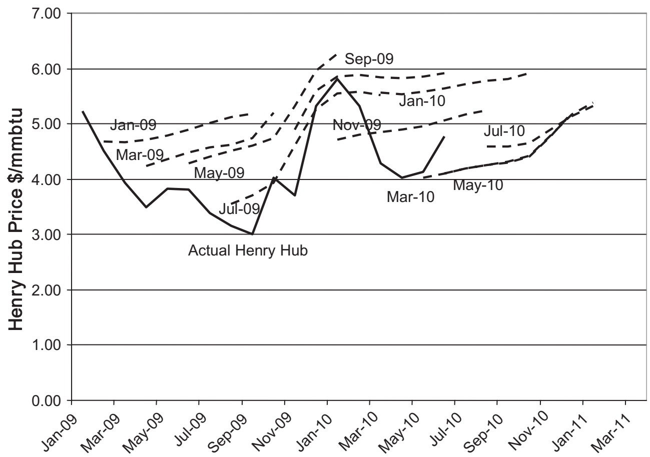


Source: RigZone Q1 2010 Land Rig Review.

propensity for over-optimism on future gas prices compared with the eventual outcome of prompt prices for the same price period. This is shown in Figure 6. This over-optimism appears to be less pronounced in 2010 than in 2009.

The US gas price environment of the early to mid-2000s and the deteriorating productivity of new conventional wells provided the impetus for shale gas development. Although the gas price fall of 2009 reduced drilling activity, this was disproportionately felt by conventional gas. Horizontal drilling activity (shale and tight gas) has recovered since

Figure 6: Henry Hub actual price outcome versus future curves



Sources: EIA, ICIS Heren.

2009. The ability to 'sell forward' production on an optimistic futures curve during 2009 also helped to cushion producers from low price realizations for physical sales on the prompt market.

IV. A description of the US shale gas production

(i) The development of the Barnett shale

The Barnett is the world's most developed shale play. Some 44 bcm of gas was produced from more than 12,000 wells in 2008, with some 3,000 new wells added in that year. In 2008 some 180 drilling rigs were operating in the Barnett shale, equal to almost 10 per cent of all the active rigs in the US. While 200 companies are active in developing the play, the six largest operators account for 80 per cent of the production. Barnett shale wells exhibit much greater variation in well productivity than those in conventional gas reservoirs. Well productivity differences are due to the reservoir quality at the well location and the effectiveness of the well completion process in creating a large area of exposed reservoir rock. Despite such productivity variations, all have very similar production profile characteristics: an early production peak followed by a rapid decline. Decline rates are much higher than for conventional wells; Barnett wells have declined by 39 per cent from the first to the second year of production and by 50 per cent from the first to the third year.

Due to the wide range of gas recoveries and production rates for Barnett shale wells, their investment economics (expressed as the discounted net present value (NPV) of future cash flows) vary significantly. Based on 2008 costs for horizontal wells, the IEA estimated the mean NPV to be $0.6m per well, but the median NPV to be zero. The wide range in NPVs reflects differences in the productivity and resource characteristics across different geographical areas of the Barnett shale. The gas price at the wellhead required to generate an after-tax return on investment of 10 per cent varies from $4/mmbtu to over $13/mmbtu across the main producing counties. More than half the horizontal wells drilled to date have been in the two most productive counties of Johnson and Tarrant (IEA, 2009, pp. 405, 406).

The key dynamic to improving the economics of shale gas has been the experimentation with different drilling and hydraulic fracturing processes. By 'tuning into' the designs and techniques that give better results in a given locality through adaptive learning, operators have been able to improve production and recovery rates, reduce unit costs, and improve profitability. This is depicted in Figure 7, which shows the feed-back loops which guide the optimization process. The intensive nature of shale gas development is further illustrated in Figure 8 which conveys the scale of 'parallel activity' involved in a shale gas play, with each horizontal strand representing an individual well.

Based on the experience of the Barnett shale play in North Texas, the following factors are deemed to be key factors for the successful development of other US shale gas plays (IEA, 2009, p. 402):

- early identification of the location and potential of the best producing areas;
- rapid leasing of large prospective areas;
- experimentation and adaptation of drilling and completion techniques and development processes akin to those used in manufacturing;
- awareness and acceptance by local communities;
- resolution of environmental issues related to fracturing and water use and disposal;
- adequate local infrastructure (particularly transportation), as most equipment and supplies (especially water) have to be trucked to and from the wells.

The focus of shale gas activity since the end of 2008 has shifted to the Haynesville (East Texas and Louisiana), the Marcellus (north-east US), and to a lesser degree the Fayetteville (Arkansas) shale, as can be seen in Figure 9.

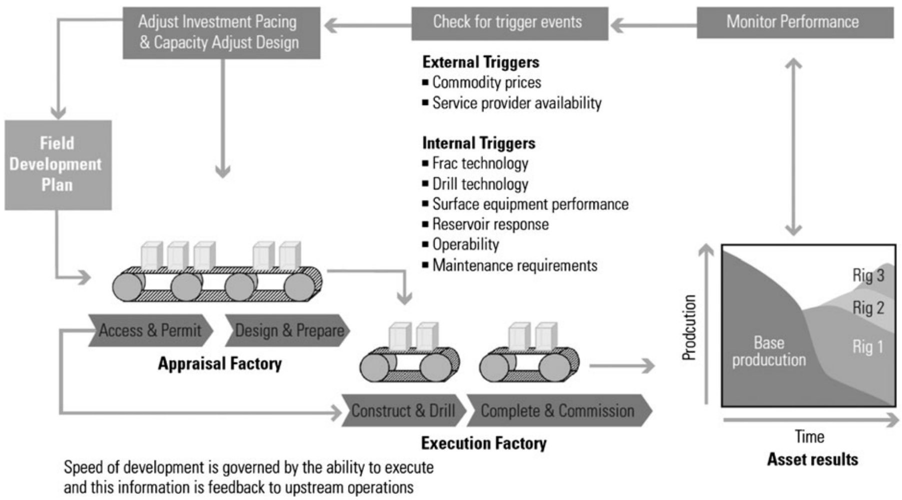
(ii) Other North American shale plays

Table 2 provides a comparison of the characteristics and scale of the leading shale gas plays in North America.

While the figures for 'gas in place' are, at first sight, impressive, the 'per km^2' measure is worthy of note. The plays listed here have a gas in place per km^2 in the range 0.2 bcm/km^2 to 3.2bcm/km^2. Based on a typical recovery factor for shale plays of 20 per cent, this corresponds to a range of recoverable gas of between 0.04 bcm/km^2 to 0.6 bcm/km^2. In the global context, comparable recoverable figures for large conventional gas reservoirs range from 2 bcm/km^2 up to 5 bcm/km^2. With shale gas plays covering large areas and requiring a greater number of wells drilled more closely together compared with conventional fields, this implies a greater surface footprint over a wider area for shale gas.

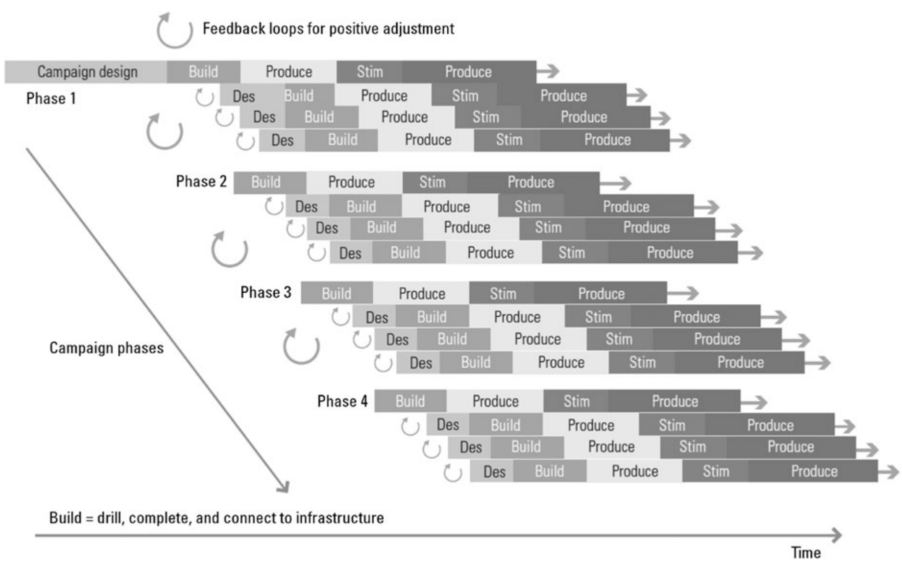
Given the success of the industry with the Barnett play, there is a widespread expectation that shale gas production in North America will continue to grow rapidly. Figure 10 shows a projection of US and Canadian shale production by play to 2030 by Kenneth B. Medlock of Rice University. There is strong growth in the Marcellus, Fayetteville, and Haynesville shales, with modest growth in others. In Canada, shale gas production is expected to commence prior to 2015, with the Horn River having the greatest growth potential in this projection.

Figure 7: Shale gas 'flexible factory' operating model



Source: Schlumberger (2009).

Figure 8: Phased and stacked campaign development—shale gas drilling



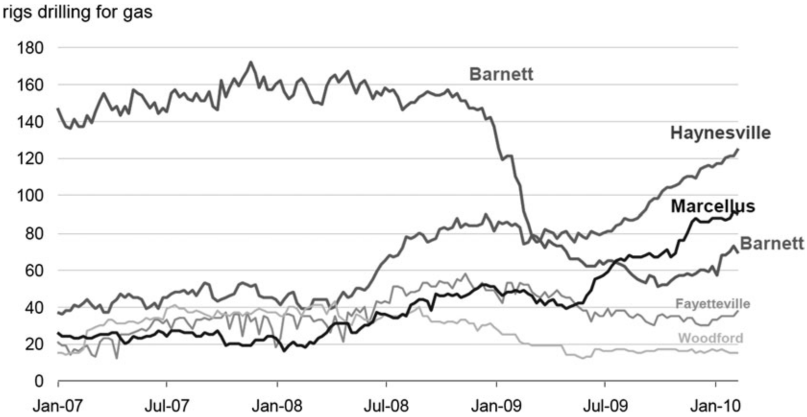
Source: Schlumberger (2009).

(iii) Potential constraints to shale gas production growth

Water consumption

While the use of directional or horizontal drilling has been employed in the upstream oil and gas industry for two decades or more, its use in shale gas has been critical in creating the necessary high reservoir exposed rock area in combination with hydraulic fracturing. A

Figure 9: Gas rigs drilling by shale play



Source: EIA presentation at FLAME Conference 2010.

Table 2: Scale of leading North American shale gas plays

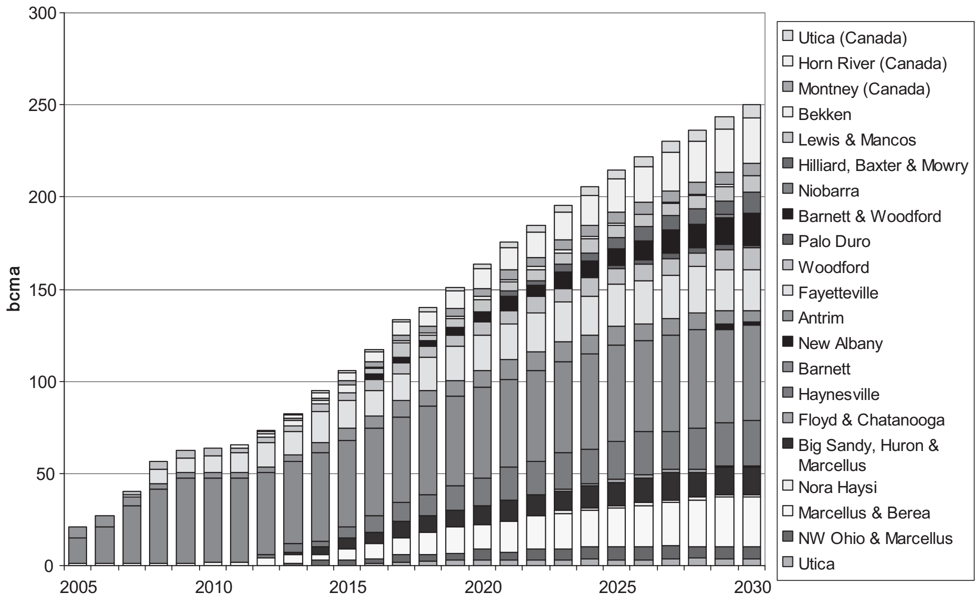
	Basin area (km^2)	Depth (metres)	Thickness (metres)	Gas in place (bcm/km^2)	Gas in place (Tcm)
Barnett	13,000	2,000–2,800	50–200	0.5–3.0	7–39
Fayetteville	23,000	300–2,100	15–100	0.5–3.0	12–69
Haynesville	23,000	3,200–4,100	60–90	1.6–2.7	37–62
Horn River	39,000	2,000–3,000	150–175	1.4–2.5	55–98
Marcellus	250,000	1,000–2,600	15–75	0.2–1.1	50–275
Montney	11,000	900–3,000	150–300	1.0–3.2	11–35
Woodford	28,000	1,800–3,300	15–70	0.4–1.3	11–36

Source: IEA (2009, p. 408).

recent Marcellus shale horizontal well has been reported as having a 4,000 foot horizontal section. Creating a horizontal well bore within the shale gas formation effectively provides a 'platform' for the second key technological application, namely hydraulic fracturing. The following description of fracturing provides an indication of the forces brought to bear in a successful shale well:

> shale gas wells are not hard to drill, but they are difficult to complete. In almost every case, the rock around the wellbore must be hydraulically fractured before the well can produce significant amounts of gas. Fracturing involves isolating sections of the well in the producing zone, then pumping fluids and proppant (grains of sand or other material used to hold the cracks open) down the wellbore through perforations in the casing and out into the shale. The pumped fluid, under pressures up to 8,000 psi, is enough to crack shale as much as 3,000 ft in each direction from the wellbore. In the deeper high-pressure shales, operators pump slickwater (a low-viscosity water-based fluid) and proppant. Nitrogen-foamed fracturing fluids are commonly pumped on shallower shales and shales with low reservoir pressures. (Schlumberger 2005, p. 4).

Figure 10: North America shale gas production, 2005–30



Source: Medlock (2009).

Table 3: Water requirements for various energy resources

Energy resource	**Range of gallons of water used per MMBTU of energy produced**
Barnett shale natural gas	1.47
Coal (no slurry transport)	2–8
Coal (with slurry transport)	13–32
Nuclear (uranium ready to use in a power plant)	8–14
Conventional oil	8–20
Syngas—coal gasification	11–26
Oil shale	22–56
Tar sands	27–68
Synfuel—Fisher Tropsch (from coal)	41–60
Enhanced oil recovery	21–2,500
Biofuels (irrigated corn ethanol, irrigates soy biodiesel)	$>$2,500

Source: Chesapeake Energy.

Chesapeake Energy, one of the foremost US shale gas operators, states that a Barnett deep shale gas well requires approximately 250,000 gallons of water during the drilling phase and an additional 3.8 million gallons on average to hydraulically fracture a horizontal deep shale gas well (Chesapeake, 2010). Placing this in context, Table 3 compares shale gas water usage with other energy sources on an energy production unit basis.

In its Barnett operations, Chesapeake uses several sources of water, including direct purchases from municipalities, regional water districts, and river authorities, rivers, ponds, lakes, and groundwater wells. Other potential water sources include industrial discharge and city treatment plant wastewater, power plant cooling water, marginal (saline) groundwater, and re-use of fracturing water. Water is typically transported by temporary pipelines or trucks to drilling locations for storage in tanks prior to use.

Perhaps the issue is not so much the quantity of water used per unit of energy output, but rather the availability of suitable water sources in the vicinity of shale drilling sites and the competing uses of such water which might result in a potential conflict and ultimately a constraint on shale gas activity in a specific location.

The service sector capacity

The recent activity growth in shale gas drilling and production has increased the demand for specialist activities provided by service companies, most notably in the areas of specialist drilling and high pressure pumping. It is estimated that unconventional gas wells in the US require 14 times more horsepower than conventional wells (Raymond James Insight, 2009). The expansion of shale and tight gas activity post-2005 has only been possibly by the parallel expansion by drilling and completion service providers, both in terms of investment in new, high-powered plant and equipment, and in the rapid mobilization of skilled resources.

The share of US onshore rigs having a horizontal drilling capability increased by a factor of five between 1998 and 2008 and now accounts for 30 per cent of land rigs (Geny, 2010). In line with the trends for the recovery in horizontally drilling land rigs shown in Figure 5, Rigzone (2010) observes that with only limited such rigs available, this could constrain the pace of activity once these are deployed. The rate at which new horizontally drilling rigs can be constructed and supplied to shale gas operators is not known. However this is likely to become a constraint on shale gas production growth, at least until the service sector expands horizontal drilling rig manufacturing capacity.

In order to mitigate against the future cost base impact of a tightening market for these services, some companies (Chesapeake, Southwestern Energy, and Williams, for example) have reversed the long-term upstream industry trend of outsourcing specialist services by building in-house capabilities in these areas.

North America has been a major producer of oil and gas throughout the last century. Although the focus has shifted over time from oil exploration towards gas and, more recently, unconventional gas, it remains an active oil and gas arena supporting a large service company sector. The US oil and gas rig count in 1949 was typically 2,000; in mid-2010 it is 1,500 (Baker Hughes). The pressure pumping market which is of particular significance to shale gas exploitation is dominated by Haliburton, Schlumberger, and Baker Hughes/BJ Services. These companies together hold a 75 per cent US market share. Starting from a large base, the sector was able to expand its skilled workforce and capabilities to meet the demand of the growth in shale gas activity, while smaller specialized companies (drilling companies and technology developers) were created by drawing on the critical mass of existing skills in the upstream industry in the context of a pro-enterprise business environment (Geny, 2010).

The rise in commodity input prices and the rise in worldwide upstream activity as a consequence of increased oil and gas prices in the 2004–8 period has resulted in a doubling of the upstream industry cost-base (CERA, 2009). This creates an especially challenging environment for shale gas developers and operators in their quest to maintain play viability through technology-driven cost-base reduction.

Environmental issues

With the expansion of hydro-fracking, there have been increasing concerns about its potential impacts on drinking water resources and public health, and environmental impacts in the vicinity of these facilities. The saline 'flowback' water pumped back to the surface after the fracturing process poses a significant environmental management challenge in the Marcellus region. The flowback's high content of total dissolved solids and other contaminants must be disposed of or adequately treated before being discharged to surface waters.

The US Environmental Protection Agency (EPA)'s Office of Research and Development is conducting a scientific study to investigate the possible relationships between hydraulic fracturing and drinking water. In its 2004 study, the EPA declared the fracking process posed 'little or no threat to underground sources of drinking water' and, on that basis, Congress a year later exempted hydraulic fracturing from federal regulation. However, there have been claims that this study was scientifically flawed and lacked objectivity. The current EPA study will conclude in 2012.

EPA hearings in mid-2010 in Texas and Colorado focused on drilling in the Barnett shale. In Texas, fear of the cancer-causing chemical benzene in the air above gas fields from processing plants and equipment has spurred tests by environmental regulators and criticism of the state's safeguards. In Colorado, numerous residents contend gas drilling has tainted their water wells.

Though the drilling rush into the Marcellus shale in Pennsylvania is barely 2 years old, more than 3,500 permits have been issued and about 1,500 wells drilled. Environmental problems are already alleged: methane leaks contaminating private water wells, major spillage of diesel and fracking chemicals above ground, and river pollution. New York state has had a virtual moratorium on drilling permits for the Marcellus shale region for 2 years while it completes an environmental review. A 'sweet spot' of the Marcellus shale—the Delaware river watershed in southern New York and north-eastern Pennsylvania that provides drinking water for 17m people from Philadelphia to New York City—is virtually off-limits to drilling at present.

While the industry claims there is no evidence that fracking chemicals contaminate drinking water, wells, or aquifers once blasted deep underground, the EPA summarized numerous reports of 'water quality incidents' in residential wells, homes, or streams in Alabama, Colorado, Montana, New Mexico, Virginia, and West Virginia. In the north-eastern Pennsylvania town of Dimock, state regulators have repeatedly penalized Houston-based Cabot Oil & Gas Corp. for contaminating the drinking water wells of 14 homes with leaking methane and for numerous spills of diesel and chemical drilling additives, including one that contaminated a wetland and killed fish.

The industry believes state oversight is sufficient and is concerned that the new EPA study will lead to new and costly safety and environmental rules and increase costs. In West Virginia, however, state officials concede they are overwhelmed trying to regulate Marcellus shale activity.

If passed, the Fracturing Responsibility and Awareness of Chemicals (FRAC) Act would remove a provision which exempted fracking from the Safe Drinking Water Act when the 2005 energy bill was passed. The EPA, in a recent statement, did not criticize its previous study. But given the rapid expansion of the industry and 'serious concerns' about the impact of hydraulic fracturing, the agency said it concluded it was necessary to conduct a peer-reviewed study that draws upon best available science, independent experts, and the public (Investors.com, 2010, pp. 1–4).

(iv) Lessons from the US shale experience

After reviewing the US experience the success of shale gas play development appears to be subject to three categories of risk and, in addition, the existence of a supportive operator and service sector and natural gas pricing environment. These elements are discussed below.

Geological risk

While the shale gas plays listed in Table 2 contain significant in-place resources, these are but estimates and carry a degree of uncertainty. However, the primary geological risk relates to the ability of the industry to locate the areas of highest well productivity within these plays. There is a risk that in some plays this will require significant investment in marginal or sub-economic wells before identifying the most favourable areas. On the downside there is a risk that even the best areas, once identified, do not possess the required level of potential well productivity.

Technology and viability risk

Somewhat related, this refers to the challenge facing operators who, having identified the most favourable areas of the play in terms of well productivity, have to transform this into a viable production investment. This is achieved through determining the optimal well design and fracturing techniques to strike a balance between capital intensity and well performance and so maximize the net present value of cashflow at the prevailing well-head price of natural gas.

Regulatory and public acceptance risk

In addition to the ongoing issues of surface and ground water contamination referred to above, and the potential for shale gas fracking to become subject to federal regulation, there is also the potential for 'nimbyism' on the part of local residents owing to the 'footprint' of intensive drilling operations in or near populated areas. There is an inherent conflict between land-owners with mineral rights, who may receive royalties of perhaps 12–20 per cent of well revenues and other lease payments, versus urban residents who are unlikely directly to benefit financially from shale gas activities. Depending on the outcome of the current EPA study (to report in 2012) and its recommendations, this is an area with significant potential to constrain the future pace of shale gas production growth within the US.

In addition to the three risk categories discussed above, there are two other important factors with a direct bearing on the future trajectory of shale gas production: *operator and service sector capacity* and the *natural gas pricing environment*.

US shale gas development to date has demonstrated that the technological breakthrough which changed a previously marginal natural gas resource into an attractive investment opportunity can result in a rapid growth production provided there is a crucial mass of suitably experienced operators and a dynamic and competitive oil and gas service industry which is able to provide the necessary specialist skills and equipment.

Notwithstanding the points made earlier regarding the impressive speed at which the upstream service sector has responded so far, there must inevitably come a point where accelerating shale gas drilling and development activity exceeds the ability of both the operators and the service sector to attract sufficient skilled human resources in a timely manner. This would be reflected by a sudden increase in cost base, which in turn would reduce the proportion of economically viable wells and hence attain an equilibrium for a given level of prevailing natural gas price.

The continued rapid growth of shale gas production may, itself, result in lower natural gas prices, thus tempering the forward growth and creating further pressure to reduce the production cost base. This, however, will depend on the extent to which other categories of North American domestic production grow or decline and on the trend in natural gas demand.

In the successful exploitation of the Barnett shale and the commencement of activity on the Marcellus and Haynesville shales, the US oil and gas industry has successfully overcome the challenges relating to geological and technology/viability risk. The regulatory and public acceptance risk remains an area of uncertainty which may restrict access to certain areas of the Marcellus play, in particular, and the outcome of the EPA study may serve to raise the cost base and/or slow access speed. The capacity of the service sector to accommodate the growth in shale gas activity has been adequate up to mid-2010, although this is an area of uncertainty going forward.

Throughout 2009 and 2010 the North American market has been importing low levels of LNG and its natural gas pricing dynamics have been driven by supply/demand dynamics. Natural gas prices in mid-2010 ($4.75/mmbtu) were below those of Europe but adequate to support further activity on the better-performing shale play areas.

V. US shale gas and its global impacts

US shale gas production growth since 2005 has already had an impact on other regional markets, in particular Europe. Its period of rapid growth has coincided with a temporary recession-driven fall in natural gas demand in Asia, Europe, and, to a limited extent, in North America itself. Furthermore this has coincided with a sudden and significant increase in global LNG supply. Of the new LNG supply projects in Qatar, Russia, Yemen, and elsewhere, some volumes were originally 'tagged' for the North American market. These volumes have been re-directed to Europe (most notably the UK) and to Asian markets on a 'spot' or short-term basis. US LNG re-gasification capacity in 2010 totals some 150 bcma, while imports of LNG in 2009 were only some 13 bcma. As a consequence of this re-direction of LNG, Europe in 2009 and 2010 has imported less Russian pipeline gas than would otherwise have been the case, and its traded gas prices have been lower than oil-indexed Russian contract prices.

A framework which depicts how regional gas markets would interact in the future, facilitated by flexible LNG and price arbitrage, is described in Rogers (2010). In this framework North America is a key actor which absorbs short-term supply fluctuations by changes in its underground gas storage facilities, and arbitrage of LNG between European oil-indexed pipeline imports and flexible LNG can periodically cause North American gas prices to converge on European oil-indexed prices. This is only possible, however, if North America is importing significant quantities of LNG (Rogers, 2010, pp. 43–53) and is, in effect, 'competing' with Europe for LNG supply. As a consequence of US shale gas production and minimal North American LNG imports, the US is currently de-linked from this global system, with US gas prices significantly lower than those of European oil-indexed contracts and traded hub prices.

The question of how long shale gas is able to keep US LNG import requirements at the low levels seen in 2009 and 2010 is, therefore, key to understanding future Atlantic gas market dynamics. This has been further underlined by the appearance of three proposals to add liquefaction plant to existing underutilized LNG regasification (import terminals). This would facilitate the processing of natural gas from the onshore distribution grid, convert it to LNG, and export it to higher priced markets. To provide a return on such investment and cover the costs of shipping and regasification charge at the destination market would require a price differential of between \$3/mmbtu and \$4/mmbtu. The aggregate capacity of the projects under consideration is 45 bcma; some 7 per cent of US domestic gas production. If these projects progress at this scale it is likely they will influence both the destination market dynamics as well as the US gas market. The ability of future US shale gas production to grow sufficiently to maintain this price spread over the useful life of these facilities is a key uncertainty; however, such is the range of opinion on future supply and demand fundamentals, it would not be surprising if such schemes attracted sufficient backing.

The EIA, in its 2010 *Energy Outlook*, depicts a future contribution of shale gas to US production as shown in Table 4.

While shale gas production doubles between 2010 and 2030, it still, in this latter year, represents only 25 per cent of US production. Future US shale gas production levels, while the focus of most attention in the media, represent only one of the several ‘moving parts’. The uncertainties on future conventional production decline and whether tight gas in the US will grow or decline are equally important, but seldom discussed in any detail.

Future US natural gas demand levels are also the subject of uncertainty, principally owing to the outcome of inter-fuel competition in the power generation sector between coal on the one hand and renewables (especially wind) on the other.

The additional dimension is the linkage to other regional natural gas markets affected by LNG and its impact on North American supply and price levels.

The future price environment in which shale gas development will proceed will therefore be determined by:

- the demand for gas in the US;
- the availability of other non-shale gas production;
- the requirement for LNG imports;
- the potential for LNG exports from the US and the ability of US shale gas production to grow to the level necessary to maintain the price spread underpinning such export projects.

VI. The potential contribution of shale gas to Europe’s natural gas supply

As shown in Table 1, Europe’s shale gas potential at 16 Tcm is relatively modest compared with other regions outside North America. This said, Europe has been a significant gas importer since the 1970s. Europe’s domestic production (including Norway) will total some 300 bcm in 2010, compared with its consumption of 600 bcm. By 2020 domestic production will likely decline to around 220 bcma, at which point Europe may be importing 65 per cent of its natural gas requirement in the form of pipeline gas from Russia, North Africa, and the Caspian region and LNG from diverse sources (Rogers 2010, p. 108).

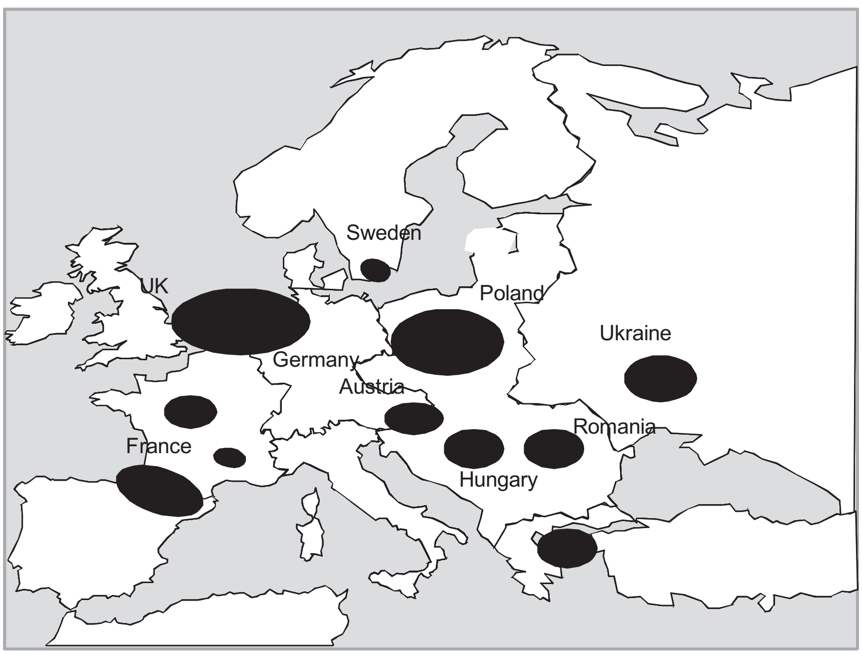
The successful exploitation of shale gas would sit well with a desire to enhance ‘security of supply’ through the reduced reliance on imports. However, this does not seem to be explicitly

Table 4: Future US gas production

	bcma		
	2010	**2020**	**2030**
Conventional and tight gas	420	377	372
Alaska	10	8	53
Shale gas	78	128	156
CBM	59	53	52
	567	**566**	**633**

Source: EIA, 2010 *Energy Outlook*.

Figure 11: European shale gas basins



Source: Based on Gas Strategies (2010, p. 3).

encompassed by EC energy policy, which is more focused on a 'dash' to renewables to meet 2020 CO_2 targets.

Figure 11 shows the location and extent of European shale gas basins. At present exploration activity is focused on areas within Germany and Poland, although there also appears to be interest in UK prospects. Europe is currently addressing the first of the risks explored above in the context of the US shale plays—i.e. *geological risk—confirming the presence, extent, and favourable characteristics of shale gas in a specific location*. Success in this phase would be the confirmation of the presence of shale gas with sufficient methane content and having a brittleness conducive to successful hydraulic fracturing.

If this phase of testing is successful, the next risk to address is that of *technology and viability risk*: determining whether a specific deposit can be developed on an economically viable basis at the prevailing market gas price by the application of technology. In this matter it is worth noting one of the conclusions of Florence Geny's paper (Geny, 2010):

> It would be inaccurate to draw general conclusions on the geological differences between US and European plays. However, there are a few emerging trends. Compared to North America, European unconventional gas basins tend to be smaller, tectonically more complex and geological units seem to be more compartmentalized. Furthermore, shales tend to be deeper, hotter, more pressurized. The quality of the shales is also different, with generally more clay content in Europe.

In addition to the need to adapt US completion and fracturing techniques to suit the characteristics of European shales, their greater depth will inevitably increase drilling costs, presenting a greater cost-base challenge compared with the US experience. The programme of work to address this risk is likely to be more prolonged than that for addressing geological risk, even if initial results are promising. That said, operators are unlikely to commit unlimited resources to such work. If a play cannot be proven to be viable within a given programme budget, work would likely be suspended in a specific location.

Perhaps the most difficult risk to assess objectively at this stage is the scale of the *regulatory and public acceptance risk* in a European context. With a lack of defined EC policy supporting shale gas development in Europe, regulatory requirements will differ depending on the geographic location of shale exploration and development activities. Europe does, at least, have historical precedent for onshore oil and gas production, especially in the Netherlands, the UK, Germany, Italy, France, Poland, and Hungary. However, the scale of water usage involved in hydraulic fracturing and its subsequent disposal may prove to be a factor which triggers a nimby response. This would depend on the availability of local water supplies and the competing uses for it. Here the outcome of the US EPA study (reporting in 2012) may be germane.

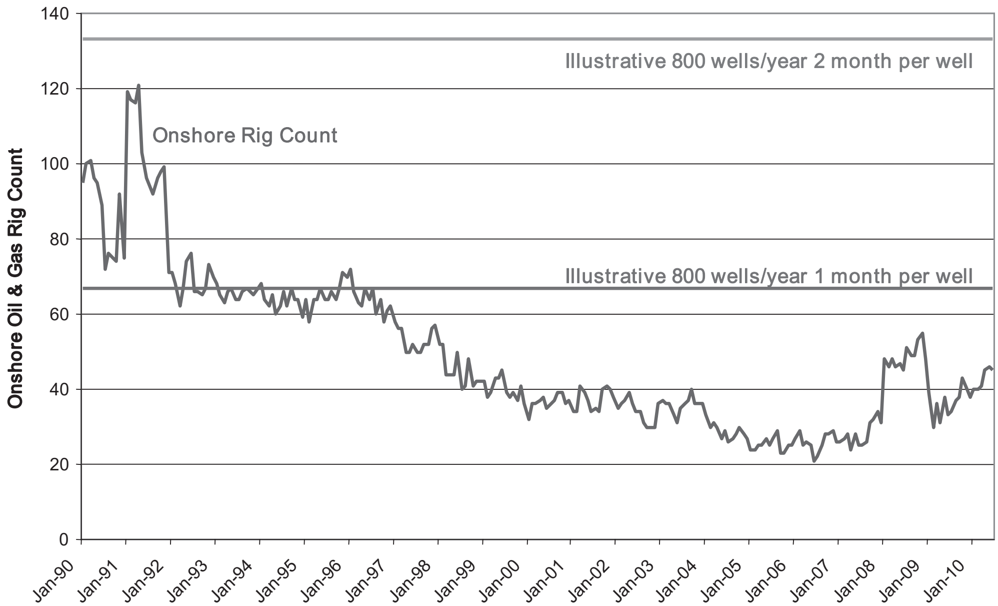
Clearly the degree of public acceptance or otherwise will also be determined by the proximity of proposed drilling sites to areas of population density. Compared with the US, one critical difference in Europe is that mineral rights are vested with the state rather than the landowner. A European landowner will not have the prospect of royalty income (a percentage levied on the gross gas sales revenue) as an inducement to permit shale gas production activity on his or her land. This said, some form of negotiated access fee and land-use fee is likely, whether or not related to production levels.

As with the US shale gas setting, there remain the important issues of resourcing requirement and shale gas production dynamics versus prevailing market gas prices to consider. Europe currently lacks the in-place skills and resources required to develop shale gas on a material scale. Figure 9 shows the historic European onshore rig count (oil and gas) which in recent years has been between 20 and 45 active wells drilling. The rig-count levels required to achieve the illustrative profile of shale gas production in Figure 12 are shown to be between 67 and 134, depending on whether the wells take 1 or 2 months to drill.

The IEA, in its 2009 *World Energy Outlook*, provides a useful illustration of the development dynamics of a new shale gas play.

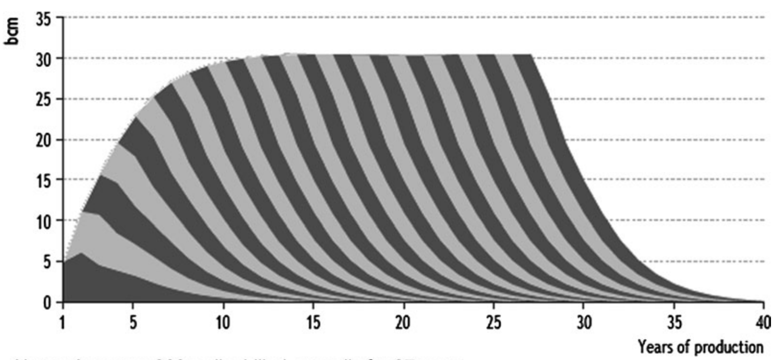
The hypothetical profile in Figure 13 assumes the constant drilling of 800 wells per year with no change in well design or production technique. The shaded segments in the profile represent production from each annual vintage. This drilling programme takes 7 years to reach a plateau of 30 bcma, but drilling must be maintained at this rate to maintain the plateau. If drilling is halted, production falls to half of the plateau in just 3 years. Given these

Figure 12: Historic European onshore rig count and illustrative shale gas drilling levels to achieve 30 bcma; 1990–2010



Source: Baker Hughes.

Figure 13: Hypothetical production profile of a new shale gas play, based on the typical profile of Barnett shale wells



Notes: Assumes 800 wells drilled annually for 27 years.
Shaded segments represent production from each vintage.
Source: IEA (2009, p. 409).

characteristics, it is possible that shale gas could play the role of swing producer, with production, as noted above, swinging up and down relatively rapidly in response to market signals.

To reiterate, the level of shale gas production achieved through this not inconsiderable effort would amount to just 10 per cent of Europe's current domestic production and 5 per cent of its annual natural gas consumption. Clearly operators developing shale gas in Europe (particularly the oil and gas majors) would undertake a process of technology and resource transfer between the US and European operations. However, if the call on such skills begins to strain the capacity of the US industry, deployment would be prioritized on the basis of the opportunities likely to yield the best financial reward. Europe's emerging shale plays would in this eventuality have to compete with those of the US.

Ultimately, the successful development of European shale will depend on whether the initially high cost base (owing to the need for the transfer of specialist skills, equipment, and horizontal drilling rigs, and potentially owing to the greater play depths), is rewarded by well productivities within a reasonable timescale, given that even the oil and gas majors will not expend unlimited capital and resources on any one opportunity.

Even assuming the three key risks outlined above are overcome, that there are no skills and resource constraints, and that the price environment is favourable, the growth of commercially viable shale gas in Europe is viewed as unlikely before 2020. This is based on an assumption that 5 years is required to establish play viability and a further 7 years to reach a production level of 30 bcma (Figure 7).

VII. Conclusions

In the US, while tight gas, CBM, and shale gas have a production history dating back to before 1990, it was the combination of a rising gas price environment in the mid-2000s and the innovative combination of horizontal drilling and hydraulic fracturing technology which catalysed the dramatic increase in shale gas production from 2005 onwards. This served to halt the decline in total US domestic gas production which had been prevailing since 2001.

Although drilling levels on the Barnett shale have fallen significantly since the end of 2008, the upstream industry is now transferring its attention to other US shale plays. In aggregate, the shale potential for North America is 109 Tcm in place. Each shale play requires optimization of the hydraulic fracturing and well-completion approach to optimize production and investment return. Shale characteristics vary between locations on the same play and consequently there is a range of well performance. The gas price at which shale gas wells break even lies in the range \$4/mmbtu to \$13/mmbtu for Barnett shale wells, based on 2008 data.

A large, dynamic and competitive upstream service sector has been a key factor in the success of US shale gas. While general global upstream unit investment costs have doubled since 2004, those relating to US shale gas have not escalated above this trend, despite the rapid activity increase.

The unforeseen increase in US shale gas production has reduced the US requirement for LNG imports considerably. As of mid-2010, North America is a 'natural gas island' with limited LNG arbitrage-induced price linkage with the gas trading hubs of Europe. The redirection of 'unwanted' LNG from the US to Europe has led to reduced Russian gas imports and has stimulated liquidity of the north-west European trading hubs.

The future outlook for US LNG imports, while of great significance for the European gas market, is difficult to foresee. The extent to which shale gas production can continue to increase before hitting skilled labour, environmental, or low gas price constraints, the future trajectory of non-shale gas production, and the outlook for US gas demand as it competes with coal and renewables in the power sector are all key factors to consider.

While shale gas plays have been identified in Europe, exploratory drilling to overcome geological risk has only recently started. If this stage is successful, more adaptive learning through experimental drilling and completion will be required to establish the commercial viability of shale gas in specific locations. This is unlikely to be a rapid process. Even if regulatory and public acceptability hurdles are overcome, Europe would require a substantial increase in its service sector capability and transfer of skills and technology from the US to achieve even 10 per cent of current domestic production levels.

With finite skills and resources and the action of price linkage through LNG arbitrage, it is quite possible to envisage a future where US and European shale gas compete with each other for resources and investment.

Glossary

algal bloom: a rapid increase or accumulation in the population of algae in an aquatic system. Algal blooms may occur in freshwater as well as marine environments. Typically, only one or a small number of phytoplankton species are involved.

associated gas: gas which is from a field which also produces oil.

bcf/d, bcfd: billion cubic feet per day (equivalent to 10.34 bcma).

bcma: billion cubic metres per annum.

coal bed methane (CBM): methane which is held within the structure of the coal matrix by adsorption. This may be produced in commercial quantities when the coal is de-pressurized and de-watered *in situ* through drilling and the application of suitable well technology.

combined-cycle gas turbine (CCGT): a gas-fired power generation plant which has a high-pressure gas-turbine cycle and a steam cycle.

dry gas: natural gas which has had some of its naturally occurring components of ethane, propane, butane, and heavier hydrocarbon components removed through processing in order to achieve sales specification.

fracking: see *hydraulic fracturing*.

gas oil: refined petroleum fraction corresponding to diesel.

GW: Gigawatt, i.e. 1 billion watts.

hub: the location, physical or virtual, where a traded market for gas is established.

Henry Hub: the pricing point for natural gas futures contracts traded on the New York Mercantile Exchange (NYMEX). It is a point on the natural gas pipeline system in Erath, Louisiana where it interconnects with nine interstate and four intrastate pipelines. Spot and future prices set at Henry Hub are denominated in \$/mmbtu (millions of British thermal units) and are generally seen to be the primary price set for the North American natural gas market.

horizontal drilling: the process of drilling a well from the surface to a subsurface location just above the target oil or gas reservoir called the ‘kickoff point’, then deviating the well bore from the vertical plane around a curve to intersect the reservoir at the ‘entry point’, with a near-horizontal inclination, and remaining within the reservoir until the desired bottom hole location is reached.

hydraulic fracturing (fracking): a process that results in the creation of fractures in rocks. The most important industrial use is in stimulating oil and gas wells, where hydraulic fracturing (in the broadest sense of the word) has been used for over 60 years in more than 1m wells. On the other hand, high-volume horizontal slick water fracturing is a recent phenomenon.

LNG: liquefied natural gas.

mmbtu: million British thermal units.
NBP: the UK's national balancing point—a virtual point (hub) in the national transmission system where gas trades are deemed to occur. It is also used as shorthand for the UK spot gas price.
North America: the USA, Canada, and Mexico.
oil and gas majors: a term generally used to describe the group of the largest publicly owned international oil and gas companies.
oil-indexed gas prices: gas prices which are subject to contractual negotiation which are determined by a formula (or formulae), containing rolling averages of crude oil or defined oil products prices.
productive capacity: of gas wells, this relates to the maximum sustainable production available from wells which are in existence. Production may be lower than this value if some wells are having their flow intentionally physically restricted.
regas terminal (regasification terminal): a terminal which receives LNG via an unloading jetty and temporarily stores it in an insulated storage tank in liquid form. When gas is required, the LNG is gasified by providing a heat input prior to entering the distribution grid.
residual fuel oil (resid.): heavy oils that are 'leftovers' from various refining processes; most often used in marine boilers and in heating plants.
rig count: the number of rotary rigs which are actively drilling on a given date. These are essentially working on exploration or development wells and represent the activity level of new production capacity development.
shale gas: natural gas formed in fine-grained shale rock (called gas shales) with low permeability in which gas has been adsorbed by clay particles or is held within minute pores and micro fractures.
spot price: the price of gas determined through trading—i.e. determined by supply and demand and/or gas on gas competition; usually referred to as 'prompt' rather than futures prices.
storage inventory: the quantity of working gas volume in storage. Working gas is distinct from 'cushion gas' which is only withdrawn from storage when a storage site is decommissioned.
tight gas: natural gas found in sandstone or carbonate reservoirs (called tight gas sands) with low permeability which prevents the gas from flowing naturally.
zooplankton: the heterotrophic (sometimes detritivorous) type of plankton. Plankton are organisms drifting in the water column of oceans, seas, and bodies of fresh water. Many zooplankton are too small to be seen individually with the naked eye.

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