US Natural Gas – A Tale with many Twists

HOWARD V ROGERS suggests North America's shale gas breakthrough has not yet turned the picture completely

Historical Context

The US shale gas phenomenon and its attendant media coverage have raised (among other issues) awareness of the importance of natural gas in the North American energy mix. The prevailing impression is one of an abundant resource which is out-competing coal in the power generating sector and which is poised to 'go global' if some of the many US and Canadian LNG export schemes are approved and come to fruition. Natural gas in North America has a much longer history than in Europe. The first US gas well was sunk in 1821, in Fredonia, New York, although it wasn't until the 1920s that any significant effort was put into building a pipeline infrastructure for gas. US natural gas production grew dramatically following the end of the Second World War, reaching a peak in the early 1970s and maintaining an undulating plateau thereafter.

The period of the 1970s and 1980s was characterised by confusing and sometimes contradictory policy initiatives and related market fundamentals shifts. For much of this period intrastate and interstate gas trade was subject to separate regulatory regimes which created a fragmented market landscape and supply distribution bottlenecks. Supply difficulties during cold winter periods gave rise to a belief that the underlying problem was a resource constraint. Although this was largely overcome through deregulation by the early 1990s, both the Clinton and Reagan administrations had promulgated incentives to accelerate drilling to augment gas production. The gas supply 'bubble' of the 1990s became a 'sausage' and as a consequence the oil and gas Majors sought offshore US (Gulf of Mexico) and international investment opportunities in preference to those of the US onshore Lower 48. From a policy and industrial consumer perspective the experience of the 1990s gave rise to a view that natural gas was a plentiful, competitively priced resource, as evidenced by the surge in investment in Combined Cycle Gas Turbine (CCGT) generation. Between 1998 and 2003 some 220 GW of new CCGT capacity was built in the USA, boosting total generation capacity (all fuel and technology types) by 28 percent (Rogers, 'LNG Trade Flows in the Atlantic Basin', OIES).

A New Millennium and a Tightening Market

Although it was not widely appreciated at the time, the gas bubble/sausage was eroded in the second half of the 1990s, manifesting itself as a narrowing gap between gas production capacity and actual production. By 2000 this 'buffer' had been virtually eliminated. Between 2000 and 2005 the US gas market experienced higher gas price volatility.

The causes of price volatility in the period 2000 to 2006 included cold weather episodes coinciding with lower than average underground gas storage inventory, hurricane-induced production shut-ins in the Gulf of Mexico Offshore (of note Hurricane Katrina in August and September 2005), and a tightening international LNG spot market towards the end of the period. Despite a rising trend in both gas price and rig count, US domestic production fell by 2.1 percent per year on average between 2001 and 2005. As this trend of falling production became evident, two almost independent supply-side responses were set in motion.

Two Tribes

The oil and gas majors began developing large gas discoveries in the international arena to form integrated LNG supply chain projects with a peak of new project approvals reached in 2005. The most notable of these were the Qatari LNG projects but in the same 'wave' can be included projects in Russia (Sakhalin), Yemen and Indonesia (Tangguh). The intention with much of the LNG associated with these projects was to keep it 'destination flexible'; however the investment in North American LNG import regasification terminals is testament to the expectation of the need for significant LNG imports into the USA by the end of the 2000s. Total North American LNG import capacity stands at 200 bcma, of which 170 bcma is in the USA.

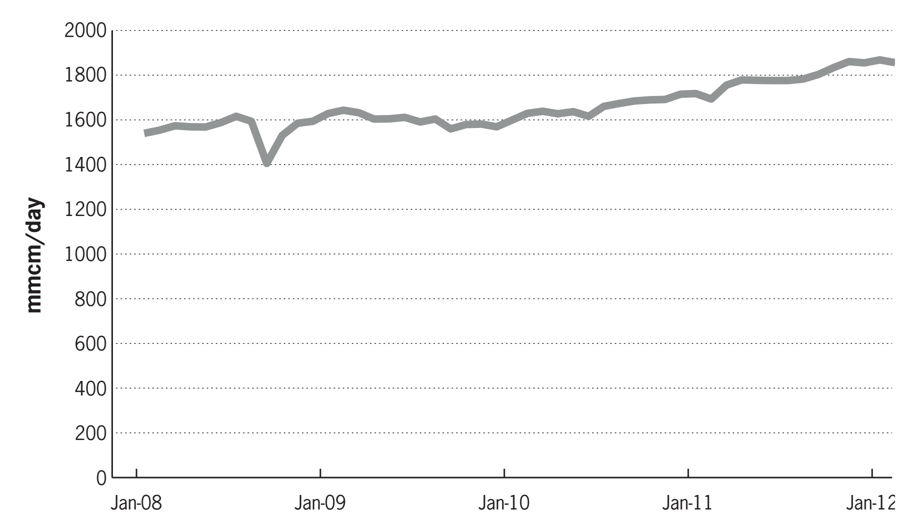
The US independents had been experimenting with combining horizontal drilling technology with hydraulic fracking to improve the well flowrate of natural gas in shale rocks, whose presence they had long been aware of through exploring for conventional gas. Shale gas is natural gas that remains captive in the relatively impermeable strata in which it was originally formed from the transformation of marine organic matter under high pressure and temperature. By 2006 shale gas production volumes were becoming significant, by 2010 they accounted for 23 percent of total US natural gas production.

In the latter half of the 2000s, despite net exports of gas to Mexico increasing, pipeline imports from Canada and LNG imports in general decreasing and US gas consumption (especially in the power sector) growing significantly, the USA from 2006 onwards developed a fundamental problem of oversupply – reflected in a growing inventory of gas in underground storage facilities. In this era of 'supply plenty', with Gulf of Mexico gas production less significant than previously, price volatility (except during the financial crisis of 2008) has been generally depressed. Henry Hub prices, which averaged \$12.69/mmBtu in June 2008, during the commodities 'bull run' just prior to the financial crisis, have since that time trended downwards, averaging just \$1.95/mmBtu in April 2012.

I See no Ships

The wave of new LNG supply, much of which was intended for the American market, came on stream in late 2009 and 2010. It was absorbed by a post-recession rapid rebound in demand for LNG in the Asian markets of Japan, South Korea, Taiwan, India and China and in Europe, which suffered abnormally cold winter conditions at the beginning and end of 2010 (and hence high space heating demand). Nevertheless the impact of recession and the position of plentiful supply in Europe created a wide differential between oil indexed pipeline gas under long-term contracts (principally from

Figure 1: US Monthly Gas Production January 2008–February 2012



Source: EIA

Russia) and traded gas hub prices, creating a strong preference for LNG supply sold on the European hubs. With limited LNG remaining after meeting Asian and European demand, US LNG import terminals in 2011 experienced a 6 percent utilisation rate; 3 percent for the first four months of 2012.

US Gas in 2012: After the Gold Rush?

In 2012, US gas production comprises conventional gas 70 percent (but in decline), shale gas 25 percent plus, with the balance being Coal Bed Methane. Due to typically rapid production decline of shale gas wells in their first year of operation, the underlying decline rate for total US natural gas production has deteriorated; in 2001 it was 23 percent per year, in 2011 32 percent. This translates into some stark statistics vis-a-vis how much production needs to be added each year from newly drilled wells to keep aggregate production level: in 2001 this was 124 bcma, in 2012 it is 227 bcma (broadly equal to twice the annual gas production of Norway). At the Henry Hub prices of $2.00/mmBtu prevailing in 2Q2012, production replacement is becoming a huge challenge. Michelle Foss ('The Outlook for US Gas Prices in 2020', OIES) estimates the Henry Hub price required to remunerate fully the build-up cost of dry shale gas at around $6/mmBtu. Clearly on this basis, current investment in dry shale gas is value-destructive and not sustainable. This is borne out in an analysis by Arthur E. Berman of the financial results of the 34 largest US shale operators in 1Q 2011 when the Henry Hub price was $4.2/mmBtu. Free cash flow generation in the quarter was $12 bn, but capital spend was $22 bn – resulting in a net cash injection requirement of $10 bn – from new equity offerings, increased borrowings or other means.

The Show Must Go On

Despite a backdrop of deteriorating gas prices, several factors have so far mitigated the economics of shale gas drilling and maintained investment momentum. Operators have been able to sell forward production on the US natural gas futures market, which has consistently been in contango since 2009. The support this has offered over prompt price outcomes however has diminished since that time. Operators who participated in the shale 'land grab' over the past few years regard lease acquisition as a 'sunk cost' in terms of making drilling decisions on a 'money-forward' basis. Landowners often require wells to be drilled within a defined time period, to avoid lease expiry which is an additional incentive supporting the drilling decision. A third factor is the effect of 'farm-in' transactions. These are common arrangements in the upstream business. If a new entrant wishes to access prospective shale acreage already leased it may reach an agreement with an incumbent operator in which the new entrant gains a working interest (equity share) of future shale gas production by paying a disproportionately high share of drilling expenditure and potentially an access fee. This arrangement has the effect of improving the operator's money forward drilling economics but also requires dry shale gas wells to be drilled contractually whereas the operator might have opted to drill more liquids-prone prospects.

To Pastures New

Despite the production momentum maintained in the face of the declining Henry Hub price since 2008, there have been clear signs that drilling activity in dry shale plays is declining. Operators have turned their attention (and drilling budgets) to 'wet' shale plays, which produce NGLs (ethane, propane and butane) and shale oil plays (with associated gas production), where oil price-related liquids revenues trump gas price considerations. Although this re-focusing of drilling still produces gas as a by-product, the volumes of gas production per well drilled are lower, for example in the 'wet' Eagleford play gas production per well is only 25 percent of that of wells in the Haynesville dry gas shale play (based on initial well production rates). The impact of this transition is beginning to show up in EIA data. Figure 1 shows US gas production reaching a plateau in September 2011, commencing a decline in January 2012.

Chesapeake Energy, one of the foremost US shale operators, in January announced a 50 percent reduction in Barnett Shale drilling and a production curtailment due to low gas prices. The Baker Hughes US rig count confirms a pronounced shift from gas to oil drilling since the beginning of November 2011.

Light at the End of the (long) Tunnel?

Of late, much media focus has been on numerous prospective LNG export projects from the USA (where these in the main involve incremental investment to transform LNG import terminals to export facilities) and from the Canadian west coast. With only the Sabine Pass facility approved to date and decisions on other projects likely deferred until after the 2012 presidential elections, the scale of US future export capacity is uncertain, with concern as to the upward impact on US gas prices a key factor. In Canada, approvals may be more easily forthcoming but greenfield investment costs will be higher; nevertheless the Kittimat project in British Columbia looks likely to proceed. While LNG projects offer a means by which 'excess' US production may be exported, it is unlikely that such schemes will commence operations prior to late 2015. This leaves US shale operators with the prospect of at least three more years of a very challenging business environment. While additional gas demand may result from the displacement of coal in the power generation sector further demand gains in the industrial sector are likely to follow an investment lag and moves to establish natural gas as a transportation fuel are likely to take several years to build up a meaningful market share.

Uncertainty in the Medium Term

In 2012 the USA emerged from a mild winter with a high underground gas storage inventory prompting fears that if production continued at year-end 2011 levels it would be likely that the end of the 2012 injection season could see Henry Hub prices testing new lows due to lack of adequate storage space. If dry shale gas drilling continues to slump and is not compensated by associated gas production from wet shale gas and shale oil drilling, this fear may be overtaken by concerns over falling total US gas production.
If such a trend becomes established, it would trigger upward pressure on Henry Hub prices. Such a rise in those prices would be restrained for a period by fuel switching in the power sector. As gas prices rise relative to coal, a reversal of the recent switch from coal to gas would take place at gas prices in the range $3 to $4/mmBtu. On eventually reaching $6/

mmBtu one might rationally expect an increase in dry shale gas drilling activity; however given the recent financial pain suffered in this sector and the more secure alternative of shale plays driven by crude oil prices, this increased activity may be slow in materialising, resulting in a classic commodity cycle price overshoot for gas. Assuming that at some point high US gas prices do result in renewed dry shale gas drilling activity, the key question is 'what is the shale gas production response to higher prices?'

Despite the high gas resource numbers quoted for the various US shale plays, ultimately the only meaningful assessment is the volume of gas that will flow through commercially viable wells. In the US plays so far developed, activity has concentrated on the play 'sweet spots' – the areas where well flow rates are highest and which best support economically viable production. These sweet spots may account for only 10 percent of total play volumes and already there are signs that the costs of incremental production additions on the Haynesville and Barnett plays are showing diminishing returns, i.e. that the best parts of the play have already been exploited. Given the inherent uncertainty over well flow rates from future wells on a shale play, the likely volume of viable production at higher future Henry Hub prices is a huge uncertainty. Yet this is exactly the nub of the issue when decisions on whether to authorise additional future US LNG export projects are considered.

If the shale production response to higher prices is poor, despite drilling investment forthcoming, then Henry Hub prices will rise, and LNG export economics will deteriorate. In this scenario, eventually the USA may be required to import higher quantities of LNG in which case Henry Hub would need to rise to European hub price levels in order to compete for available LNG supplies.

If the shale production response to higher prices is highly positive then abundant production growth would be available both to supply LNG export projects and at the same time meet US natural gas consumption needs at moderate (circa \$6/mmBtu) prices.

Conclusions

The US natural gas arena has, over the past three decades, undergone significant regulatory changes that have interacted with its supply-demand-price dynamics. The decisions required on whether to allow the export of significant volumes of LNG might have equally significant consequences. In an optimistic scenario for dry shale gas production (in terms of its production volume–price response) they could establish an arbitrage-driven linkage between a sustainable Henry Hub price and the destination markets of the European gas hubs and the Asian LNG spot market. In a less optimistic scenario for a dry shale gas production–price response, such LNG export schemes could become stranded assets should the USA in time need to import LNG to meet its gas consumption requirement. Prior to the start-up of US LNG export projects (2015 at the earliest), the industry will be subject to rationalisation in order to establish a more sustainable price level. Data on US production and rig counts indicate that this has already started. This is unlikely to be a smooth transition to a new equilibrium state, rather a classic commodity supply–price overshoot. The story of US natural gas is likely to yield a few more twists before the tale is concluded. ■