Howard Rogers Peer Review Comments 1st March 2016 HVR 27/6/16

General/Preamble

I have been asked to comment on two components of a report assessing how potential UK shale gas production impacts on the UK's carbon budget. As Director of the Oxford Institute for Energy Studies Natural Gas Research Programme I commission and supervise research papers on a wide range of global natural gas supply, demand, price formations, market dynamics and geopolitical topics. My programme's research can be accessed at: https://www.oxfordenergy.org/gas-programme/

On shale gas specifically I have either authored or supervised some key research papers; namely:

'Shale Gas – the unfolding story', Howard Rogers, Oxford Review of Economic Policy', Volume 27, Number 1, Spring 2011, Pages 117 – 143

'Can Unconventional Gas be a Game Changer in European Gas Markets?', Florence Geny, OIES, NG 46, December 2010, http://www.oxfordenergy.org/2010/12/can-unconventional-gas-be-a-game-changer-in-european-gas-markets/

'Will there be a Shale Gas Revolution in China by 2020?', Fan Gao, OIES, NG 61, April 2012, http://www.oxfordenergy.org/2012/04/will-there-be-a-shale-gas-revolution-in-china-by-2020/

'UK Shale Gas – Hype, Reality and Difficult Questions', Howard Rogers, OIES, June 2013, http://www.oxfordenergy.org/2013/07/uk-shale-gas-hype-reality-and-difficult-questions/

Comments on Chapter 2 – Production Scenarios (source text in italics)

The UK shale industry is currently in the early stages of development. Consistent well flow-rates of oil and gas across each of the basins can only be proved if there is a period of exploration. If flow-rate levels consistent with commercial exploitation can be established over a number of exploration wells the industry might then move on to development well drilling and the production phase of operations.

From the US experience, flowrates from wells drilled in different points within plays vary significantly (as allegedly do flows from different stages of a horizontal fracked lateral). This has given rise to the 'sweet spot' construct – i.e. where shale organic content, permeability, brittleness or 'frack-ability' and pressure, together produce the highest flowrates. So rather than an exploration/appraisal programme merely to test 'average' well flowrates – if they vary as they do in the US, this may be more a challenge of finding the play 'sweet spots' with some wells resulting in very low and patently uneconomic flowrates.

The rate at which a UK onshore petroleum industry might develop is uncertain, and depends on the rate at which the industry can feasibly be ramped up: economic factors affecting the profitability of production; the time required for and complexity of the planning and approval process; and, related to this, the extent to which public acceptability issues are a constraint.

The other important factor here is the speed and complexity of the approval/planning process. In the US a key feature which led to rapid exploration, identification of sweet-spots and the acceleration of development drilling was the speed of regulatory approval processes – in addition to quick bi-lateral deals with land-owners who hold mineral rights.

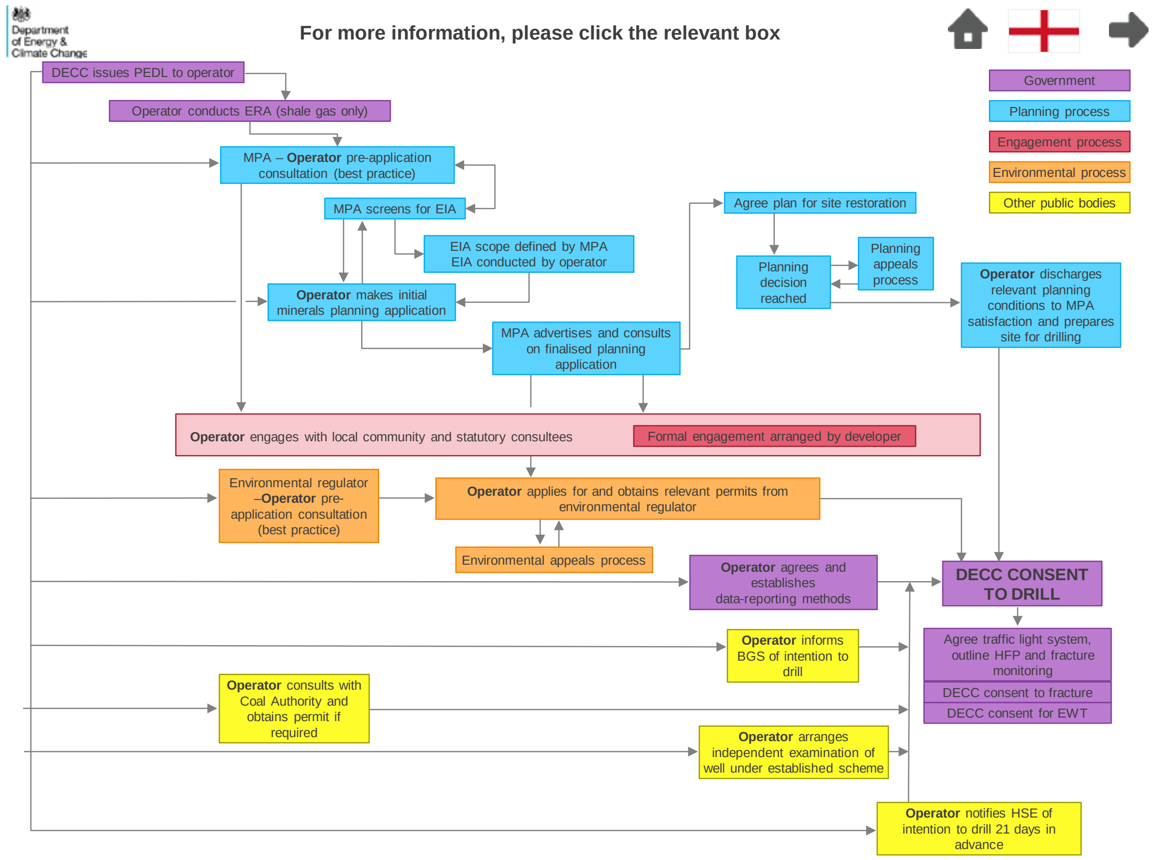
The fiscal framework should not be forgotten here. Investment economic decisions are based on projections of after-tax cashflow.

Drilling the well. The cost of drilling a well is related to the depth of the well and the length of lateral. The costs to drill wells in the US are decreasing, with recent cost estimates as low as $2.6m per well. However, this does not take into account the greater depth of the UK shale formations; UK costs could be more comparable to the Haynesville formation that underlies parts of the US states of Arkansas, Louisiana and Texas, where wells cost in the region of $9m to drill.

It is also important to appreciate that the cost of wells will undoubtedly reduce through time as a) operators 'tune into' the optimum well and completion design for the shale gas play in question and b) supply chain logistics are optimised and economies of scale are brought to bear.

Planning. Sites in the UK could require security during the well development stage and potentially beyond, adding to the costs for the site. Planning permission can be difficult to obtain due to local impacts, with two wells in Lancashire failing on noise and traffic grounds; this process took over 15 months to assess. However, the Government recently announced a plan to fast-track the planning process for councils to come up with a planning decision within a16-week statutory timeframe.

At present the perception is that the approval process is overly complex and involves too many agencies – as shown on the attached diagram.



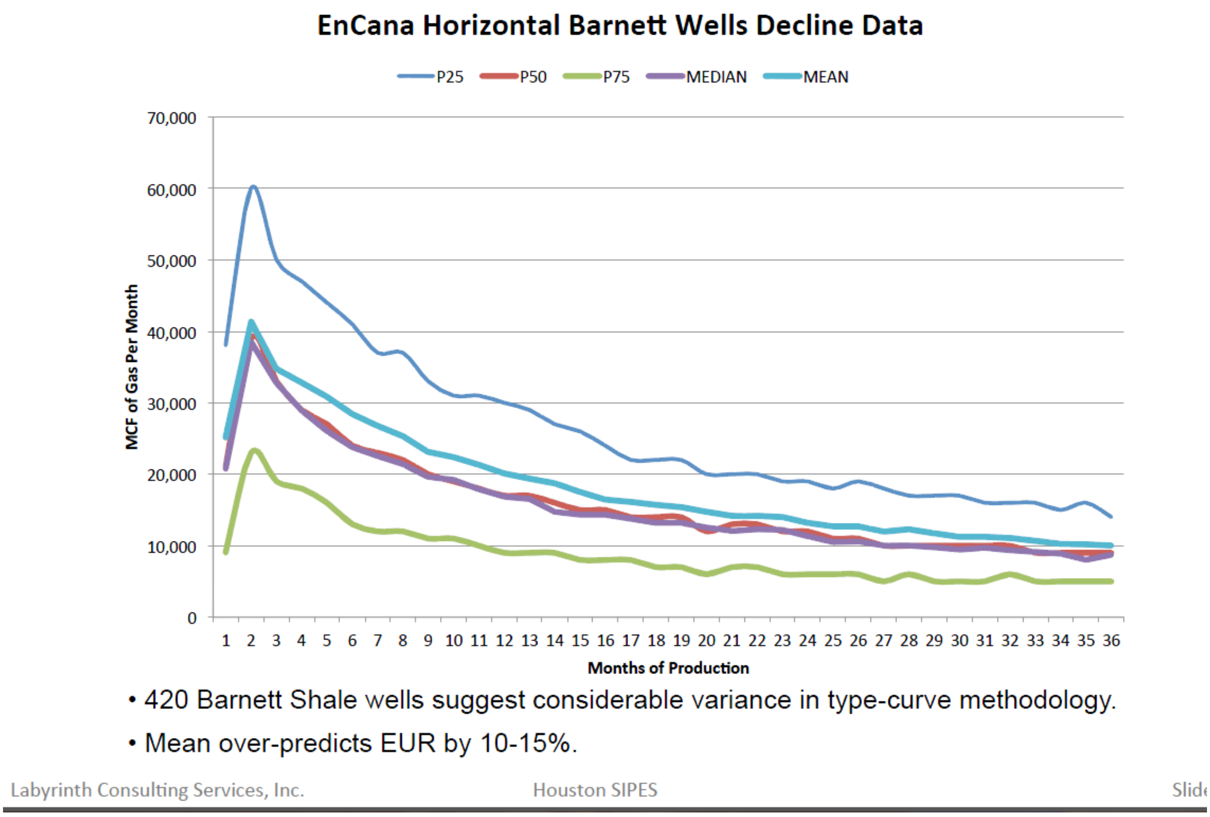
Source:
https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/265978/Onshore_UK_oil_and_gas_exploration_all_countries_Dec13.pptx

Composition. The composition of hydrocarbons extracted varies considerably between wells. Generally gas is categorised into dry gas and wet gas: dry gas is mainly (greater than 90%) methane; wet gas contains a greater proportion of gases such as ethane, propane, butane and gas condensate, which tend to have a greater value than methane and may be used as feedstocks in petrochemical plants rather than combusted for energy.

Based on US experience it is probably more accurate to say that hydrocarbon composition varies between shale gas plays and also between different areas (and possibly depths) within the same shale gas play.

Box 2.1 Well productivity

It is important to make the point that shale gas well flowrates are generally lower than conventional gas wells and that flowrates decline more rapidly. Well profiles from the Barnett shale in Texas are shown below:



This illustrates the rapid decline rates and the variability in flowrates between different wells on the same shale play.

Box 2.2 – Potential for Multilaterals

Given the higher population density of much of the UK compared with US shale producing regions, and the apparent high thickness of the UK shale strata – it is likely that there will be pressure to minimise visual intrusion and optimise traffic logistics by drilling several multi-lateral wells from the same location (or 'pad') rather than wells at many different locations to drain the same shale area. This said, drilling activity at these 'pad' locations may last some while if a dozen or so wells are drilling sequentially, each having multiple laterals.

Should onshore production be profitable, the prevailing taxation regime will determine how much of the profits are retained by the producer and how much goes to the Exchequer. While there is a taxation regime currently in place, it is likely that this will be adjusted when more is known about the economics and profitability of UK production.

If investors believe that the tax regime will be changed once their costs are sunk – this is a huge disincentive. It is better and more realistic to say that the tax regime may be re-tuned should shale gas development result in unforeseen super-profits for the industry or alternatively relaxed if this is necessary to ensure sufficient profitability for investment to proceed.

Prices and Shale Gas Economics

While energy price projections are always fraught with difficulty, understanding the fundamental drivers at least provides a basis from which to judge the likely price dynamics.

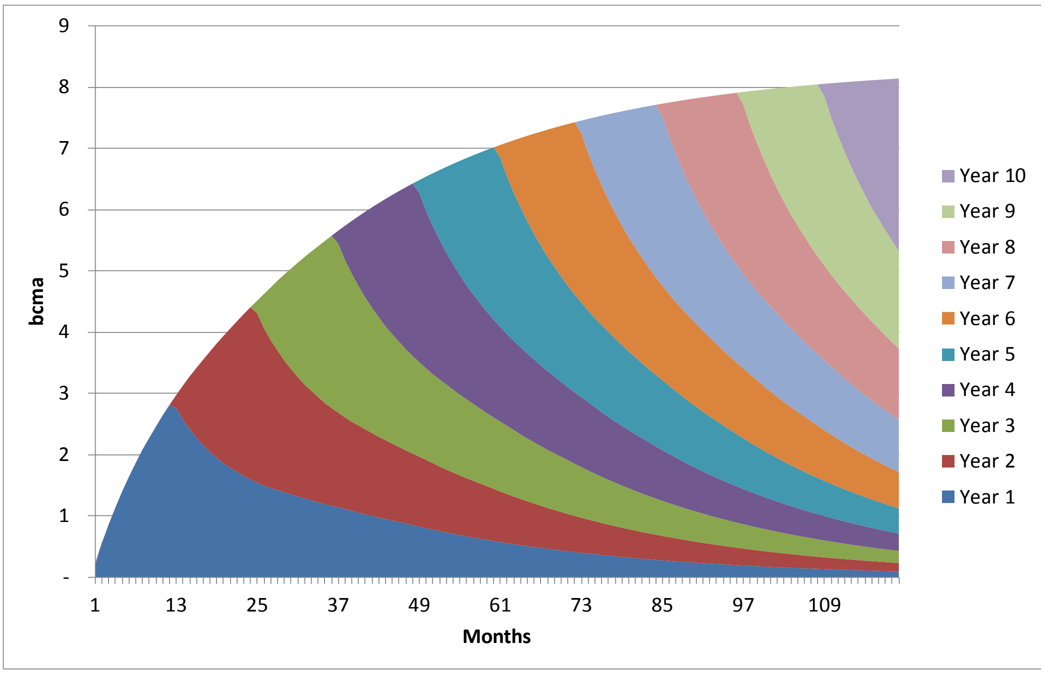
UK and European traded hub gas prices are currently depressed by ongoing stagnant demand and the lower levels of Russian oil-indexed contract prices. These contract prices act as a 'ceiling' on hub prices since if hub prices rise above them, contract buyers will increase nominations and sell the extra gas on the hubs until hub prices fall to the same level as those under the contract. However, when oil prices recover, hub prices are likely to remain depressed due to the large volumes of LNG from new projects in Australia and the US coming onstream over the next four years. This 'glut' of LNG should clear in the early 2020s – absorbed by Asian demand growth and continued decline in North Sea and Dutch gas production and possibly an increase in European gas demand in the power sector.

In the early 2020s, as investment in new globally tradeable gas supplies is required, one should expect gas prices to rise to the Long Run Marginal Cost of new production. This is judged to be in the region of $8 to $10/mmbtu. It is possible that prices stay lower for longer if Russia increases its exports to Europe of its West Siberia 'bubble' of already developed gas. Given the likely exploration and appraisal lead time, UK shale gas, if successful, should see development around the time UK and continental European gas prices rise towards Long Run Marginal Cost Levels.

Production Outlooks

In the absence of exploration well flowrate test data for UK shale plays it is only possible to construct success case production profiles by making assumptions about a) well flowrate a and decline rates b) the number of wells drilled per year, and c) the number or multilaterals drilled for each well. The range and combination of assumptions in the cases selected in Chapter 4 explain the variation of the production outlooks.

In my paper of 2013 'UK Shale Gas – Hype, Reality and Difficult Questions' (https://www.oxfordenergy.org/publications/uk-shale-gas-hype-reality-and-difficult-questions/) I constructed a hypothetical UK shale gas production profile by taking the average Barnett well profile and assumed that 300 wells (single lateral) were drilled per year for 10 years. The resulting aggregate production profile is shown below:



Illustrative Shale Gas Production Profile Assuming 300 additional wells per year (25 Pads) based on an Average Barnett Shale Gas Well Profile.

Production reached a plateau of some 8 bcma (85 TWh/Year). This is low compared with most of the cases in Chapter 2. My concern was that I find it difficult to imagine that UK public opinion would countenance this level of onshore drilling intensity given UK population density and the higher level of visual intrusion compare with the US. Clearly the use of multilaterals might help in this regard, albeit drilling activity with associated visual intrusion and traffic would persist at a specific location for possibly a year or more. Again however it should be stressed that all these cases are hypothetical in the absence of well flowrates.

Impact on prices

I agree that it is unlikely that UK shale gas production would have a measurable impact on wholesale gas prices. The UK is physically connected to the continental European market and correlation between NBP and the Dutch TTF hub price is very high. Europe in turn is ‘connected’ by flexible LNG arbitrage with the Asian LNG spot market and, soon, US Henry Hub prices (although shipping costs and liquefaction costs will create a price differential).

Comments on the Technical Annex

I support the use of the SGI paper as a key source for this Annex.

Well Completions: I understand that Reduced Emissions Completions are now mandatory in most US locations. I expect this would be the case in the UK.

Normal operations. '*Brantley et al found emissions from the well pad to be higher than Allen, but the author suggested the difference was due to the sites measured were older with low productivity'*.

Liquids Unloading: It is important to understand that liquids unloading is a function of:

a) the composition of the shale gas in the shale gas strata. If the shale contains a notable concentration of higher alkanes in addition to methane and ethane, these are more likely to accumulate in the liquid phase at the base of the well as pressure (retrograde condensation). At present we do not know the composition of UK shale gas and this may change between and across shale plays – so it may not be a problem in the UK. (For example I am not aware this has been an issue for onshore UK conventional gas wells).
b) the use (or lack of) measures taken to prevent accumulated liquids entering the atmosphere when the well bore is cleared of liquids to allow gas to flow to surface.

The SGI report describes approaches used to minimise emissions from liquids unloading.

Monitoring 'Super Emitters'. I would expect that the relatively few centres of UK shale gas production would be required to install leak monitoring systems (i.e. detectors for ambient methane levels) and thus avoid anything other than very short term leakage of any significance.

Howard Rogers 3rd March 2016