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Unconventional shale gas extraction: present and future affects

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Abstract: *In the 1990s the extraction of unconventional shale gas extraction increases in the USA due to national and global demand of energy. The expansion of shale gas production will provide low carbon economy, therefore it is a positive side of low greenhouse gas emissions in the atmosphere and considering the benefit sides it has been referred to as a bridging fuel. Horizontal drilling and hydraulic fracturing are the two technologies by the combination with one another; provide the potential to unlock tighter shale gas formations. The conventional natural gas reserves declining globally, so that shale gas extraction emerged as a potentially significant new source of unconventional gas in the USA, the UK and elsewhere. This paper discusses the procedure of extraction, benefits and disadvantages of unconventional shale gas.*

Keywords: Shale gas, Fracking, Flowback.

INTRODUCTION

Conventional gas reservoirs are areas where gas has been trapped and the pressure of the earth often pushes the gas upward through tiny holes and fractures in rock until it reaches a layer of impermeable rock where the gas becomes trapped. This gas is relatively easy to extract, as it will naturally flow out of the reservoir when a well is drilled. Unconventional gas occurs in formations where the permeability is so low that gas cannot easily flow (tight sands), or where the gas is tightly adsorbed or attached to the rock (coalbed methane).

In the energy hungry world conventional natural gas reserves declining globally, so that shale gas extraction emerged as a potentially significant new source of unconventional gas. Gas shales are consists of organic rich shale, a sedimentary rock formed from deposits of mud, clay, slit and organic matter. Shale looks like the slate of a chalkboard and generally has ultra low permeability. Layers of shale sometimes become hundreds of feet thick and covering millions of acres which are both the source and reservoir for natural gas. These shales are rich in organic carbon. The methane in organic shales was created in the rock itself over millions of years. The USA ingenuity and steady research have led to new ways to extract gas from shales, making hundreds of trillions of cubic feet of gas technically recoverable where these were not possible once. In many oil fields, shale forms the geologic seal that retains the oil and gas within producing reservoirs, preventing hydrocarbons from escaping to the surface. The demand of unconventional shale gas extraction increases in the USA, the UK and elsewhere. The US consumes about 22 Tm^3/year (trillion cubic meters per year) and the Marcellus shale (will be discussed later) may provide more than 20 years of consumption for the entire country. More than 450,000 wells have been drilled in the Appalachian Basin of the Marcellus over the last 150 years and they have produced only 1.33Tm^3, less than 10% of the projected production from the Marcellus. The largest conventional natural gas field in North America is the Hugoton Field of Kansas with only 2.3 Tm^3 which is about 1/6 times of the Marcellus shale (Wrightstone 2011). Current increasing demand and lagging supply mean high prices for both oil and gas, making exploitation of the USA unconventional gas plays suddenly far more lucrative for producers. It is estimated that

current US shale gas recoverable reserves are 14.16 to 28.3Tm^3. In 2005, approximately 0.28Tm^3 of conventional gas was produced in the USA, versus 0.23Tm^3 of unconventional gas. Hydraulic fracturing and horizontal drilling (fracking) are the key enabling technologies that first made recovery of shale gas economically viable with their introduction in the Barnett Shale of Texas during the 1990s. Across the USA from the West Coast to the Northeast, about 19 geographic basins are recognized sources of shale gas, where an estimated 35,000 wells were drilled in 2006. At present a significant commercial gas shale production occurs in the Barnett Shale in the Fort Worth Basin, Lewis Shale in the San Juan Basin, Antrim Shale in the Michigan Basin, Marcellus Shale and others in the Appalachian Basin, and New Albany Shale in the Illinois Basin.

In 2009 only in the USA the unconventional gas production exceeded that of conventional gas. The US Department of Energy predicts that by 2035 total domestic production will grow by 20% where 75% will provide by unconventional gas (Energy Information Administration, EIA 2010). In the USA the production of shale gas was 7.6Bm^3 (billion cubic meters) in 1990 which was 1.4% of total US gas supply. In 2009 the shale gas production reached to 93Bm^3 which was 14.3% of total US gas supply (EIA 2010). It is estimated that the shale gas extraction in the USA will increase continually in future. The National Research Council (2009) expressed that emissions from shale gas extraction may be greater than from conventional gas.

The presence of natural gas, primarily methane in the shale layers of sedimentary rock formations which were deposited in ancient seas has been recognized for many years. The difficulty in extracting the gas from these rocks has meant that oil and gas companies have historically chosen to tap the more permeable sandstone or limestone layers which give up their gas more easily. Shale gas extraction companies are now more confident than ever that they are in profitable business. They demand that shale gas extraction is a new miracle in which high capital costs combined with low gas prices obviously give high profit.

There are 23.4Tm^3 of natural gas which are recoverable from US shales using currently available technology. The USA currently consumes about 0.65Tm^3 per year, of which the USA produce about 0.57Tm^3 and import the rest, so the shale gas resource alone represents about 36 years of current consumption. One Trillion cubic feet (0.283Tm^3) of natural gas is enough to heat 15 million homes for 1 year, generate 100 billion kilowatt-hours of electricity, or fuel 12 million natural-gas-fired vehicles for 1 year.

SHALE GAS EXTRACTION PROCESS

The majority of US gas shale extraction came from four basins:

- San Juan Basin, New Mexico/Colorado; 1.6Mm^3/day.
- Antrim Shale, Michigan; 10.87 Mm^3/d.
- Appalachian/Ohio shales; 12.4 Mm^3/d.
- Barnett Shale, Fort Worth Basin, Texas; 34.9 Mm^3/d.

Horizontal drilling and hydraulic fracturing (fracking) are the two technologies by the combination with one another; provide the potential to unlock tighter shale gas formations. Hydraulic fracturing is the most popular process in unconventional gas extraction, because of significant advances in horizontal drilling and well stimulation technologies and refinement in the cost effectiveness of these technologies. Hydraulic

fracturing is a well stimulation technique which consists of pumping into the formation very large volumes of fresh water which usually treated with a friction render, biocides, scale inhibitor, surfactants and a propping agent (usually sand) down the wellbore under high pressure to create fractures in the hydrocarbon bearing rock. These fractures start at the injection well and then extend as much as a few hundred meters into the reservoir rock. About 15% to 80% of the injected fluids come out to the surface with the hydrocarbons (Environmental Protection Agency, EPA 2010b). These fractures start at the injection well which can extend up to few hundred meters into the reservoir rock. The proppant keep the fractures open to flow the hydrocarbons into the wellbore. The equipment and technology of horizontal drilling is similar to the vertical drilling but development and extraction processes differ between conventional gas and unconventional shale gas production.

Hydraulic fracturing and fracking processes developed step by step clustering of several wells on multi-well pads and we show in table-1 the progresses in such type of drilling process from 1983 to 2007 (Wood et al. 2011).

Table 1: Development of shale gas technologies. Source: New York State (2009).

1983	First gas well drilled in Barnett Shale in Texas.
1980-1990s	Cross-linked gel fracturing fluids developed and used in vertical wells.
1991	First horizontal well drilled in Barnett Shale.
1996	Slickwater fracturing fluids introduced.
1998	Slickwater fracturing of originally gel-fractured wells.
2002	Multi-stage slickwater fracturing of horizontal wells.
2003	First hydraulic fracturing of Marcellus shale.
2007	Use of multi-well pads and cluster drilling.

Commonly 6 to 8 wells are drilled (sometimes number of wells may be up to 16) sequentially in parallel rows from each pad and each well typically being around 5-8m apart. Each horizontal wellbore may typically be around 1 to 1.5km in lateral length (Wood et al. 2011). Wells are drilled vertically to intersect the shale formations at depths that typically range from 1,829 to more than 4,267m. Each pad needs an area sufficient to accommodate fluid storage and equipment associated with the high-volume fracturing operations as well as the larger equipment associated with horizontal drilling. In the Northern Pennsylvania this method is using at Marcellus shale reserves. In terms of spacing well pads, New York State (2009) identifies a maximum spacing of 3.5pads/ km^2 but in the UK the composite energy has estimated that 1-1.5pads/km^2 should be enough in a UK setting. An average sized multi-well pad is likely to be 1.5-2ha (1 hectare = 10,000m^2) in size during the drilling and fracturing phase. Gas shale reservoirs in the United States tend to be found within three depth ranges between 76.2 and 2,438m. The New Albany and Antrim shales, have some 9,000 wells in the range of 76.2 to 610m. In the Appalachian basin shales and the Devonian and Lewis shales, there are about 20,000 wells from 915 to 1,524m. Although the Barnett and Woodford shales are much deeper, the Caney and Fayetteville shales are from 610m to 1,829m, with most of the reservoirs between 762 and 1,372m. A good shale gas prospect has a shale thickness between 92 and 183m (Frantz and Jochen 2005).

The vertical sections of the wells range from 1,524 to 2,743m below ground depending upon the depth and thickness of the shale. Once the vertical section reaches the *kick off* point above the Marcellus shale or Utica shale formation, the well is turned to bore horizontally for another 914 to 1,524m or more.

Well Casing

A variety of well casing be installed to seal the well from surrounding formations and to keep the stabilization of the completed well. Casing is a typically steel pipe lining the inside of the drilled hole and cemented in place. There are five types of casing strings, each installed at different stages in drilling which are as follows (Wood et al. 2011):

Conductor Casing: This type of casing is used during the first phase of drilling. A shallow steel conductor casing is installed vertically to reinforce and stabilize the ground surface.

Surface casing: When conductor casing is installed then drilling continues to the bottom of freshwater aquifers, at this stage a surface casing is inserted and cemented in. Ground Water Protection Council (GWPC 2009a) survey of 27 States and found that 25 required the surface casing to extend below the deepest aquifer. Cement circulation may be used to fill the entire space between the casing and the annulus wellbore from the bottom of the surface casing to the surface. Cement is pumped down the inside of the casing, forcing it up from the bottom of the casing into the space between the outside of the casing and the wellbore. GWPC (2009a) states that circulation of cement on surface casing is not a universal requirement and in some states cementing of the annular space is required across only the deepest ground water zone but not all ground water zones. Once surface casing is in place then some states may require operators to install blowout prevention equipment at the surface to prevent any pressurized fluids encountered during drilling from moving up the well through the space between the drill pipe and the surface casing (Zoback et al. 2010).

Intermediate casing: This type of casing is not usually required. It is usually only required for specific reasons such as additional control of fluid flow and pressure effects, or for the protection of other resources such as minable coals or gas storage zones.

Production casing: After the surface casing is set or intermediate casing if needed, the well is drilled to the target formation and a production casing is installed either at the top of the target formation or into it depending upon whether the well will be completed open-hole or through perforated casing.

Well tubing: A few states also require the use of well tubing inserted inside the above described casings. Tubing, like casing, typically consists of steel pipe but it is not usually cemented into the well.

THE COMPOSITION OF THE FRACTURING FLUID

The composition of the fracturing fluid varies from one product to another according to the characteristics of the target formation and operational objectives. The fracturing fluid used in modern slickwater fracturing is comprised of about 98% water and sand, and about 2% chemical additives (GWPC 2009b). The water treating fluid maximizes the horizontal length of the fracture while minimizing the vertical fracture height. As a result a large volume of shale gas is extracted from wells efficiently. The activities of different components in the fracturing fluid additives being as follows (Wood et al. 2011):

- Proppant open fractures result in increased surface area and allows gas/fluids to flow more freely to the wellbore.
- Breaker reduces the viscosity of the fluid in order to release proppant into fractures and enhance the recovery of the fracturing fluid.
- Biocide inhibits growth of organisms that could produce gases (particularly hydrogen sulfide) that could contaminate methane gas. It also prevents the growth of bacteria which can reduce the ability of the fluid to carry proppant into the fractures.
- Acid cleans up perforation intervals of cement and drilling mud prior to fracturing fluid injection, and provides accessible path to formation.
- Clay stabilizer prevents swelling and migration of formation clays which could block pore spaces thereby reducing permeability.
- Corrosion inhibitor reduces rust formation on steel tubing, well casings, tools, and tanks (used only in fracturing fluids that contain acid).
- Friction reducer allows fracture fluids to be injected at optimum rates and pressures by minimizing friction.
- The fluid viscosity is increased using phosphate esters combined with metals. The metals are referred to as crosslinking agents. The increased fracturing fluid viscosity allows the fluid to carry more proppant into the fractures.
- Gelling agent increases fracturing fluid viscosity, allowing the fluid to carry more proppant into the fractures.
- Iron control prevents the precipitation of metal oxides which could plug off the formation.
- Scale inhibitor prevents the precipitation of carbonates and sulfates (calcium carbonate, calcium sulfate, barium sulfate) which could plug off the formation.
- Surfactant reduces fracturing fluid surface tension thereby aiding fluid recovery.

THE QUANTITY AND THE PRESSURE OF THE FLUIDS

Each stage in a multi-stage fracturing operation requires about 1,100-2,200m^3 of water. Therefore the entire multi-stage fracturing operation for a single well requires about 9,000-29,000m^3 of water and, with chemical additives of up to 2% by volume, about 180-580m^3 of chemical additives. For all fracturing operations carried out on a six well pad, a total of 54,000-174,000m^3 of water would be required for a first fracking procedure and, with chemical additives of up to 2% by volume, about 1,000-3,500m^3 of chemicals. In addition, the wells may be re-fractured multiple times after producing for several years. The Texas Water Development Board (TWDB) report states that approximately 89% of the total water supply for the region for all purposes (municipal, agricultural, electric power generation, industrial, and mining) is provided by surface water sources, while groundwater is used for the remainder of the total demand. The

amount of water from all sources that is used for Barnett Shale (discuss in detail latter) development has been a relatively small (less than 1%), although growing, percentage of the total water use from all sources and for all purposes in the counties with Barnett Shale development. The TWDB report estimates that, out of the total water used in 2005 for Barnett Shale development, approximately 60% was groundwater from the Trinity and Woodbine Aquifers. The report further estimates that groundwater used for Barnett Shale development accounted for approximately 3% of all groundwater used in the entire study area in 2005. The TWDB report makes predictions of future water needs for all purposes, including Barnett Shale development. The low estimate for Barnett Shale development predicts a decrease of about 24,666,7051m^3 by the year 2025 and the high estimate predicts an increase from an estimated 8,881,384m^3 in 2005 to about 12,335,256 to 30,838,140m^3 per year by 2025, which corresponds to an estimated potential increase in groundwater used from 3% in 2005 to 7% to 13% by 2025. As with the development of any estimate of future conditions, the TWDB and its contractors used educated assumptions to develop reasonable low and high estimates in light of the unpredictability of the natural gas market, which would drive future drilling activity in the area (Wood et al. 2011).

New York State (2009) identifies that anticipated Marcellus shale fracturing pressures range from 5,000psi (pounds per square inch) to 10,000psi which is equivalent to 170-350 times the pressure used in a car tyre.

Large quantities of water and chemical additives must be brought to and stored on site. In terms of source water, local conditions dictate the source of water and operators may abstract water directly from surface or ground water sources themselves or may be delivered by tanker truck or pipeline. New York State (2009) reports that liquid chemical additives are stored in the containers and on the trucks on which they have been transported and delivered with the most common containers being 1-1.5m^3 high-density polyethylene steel caged cube shaped.

Hoses are used to transfer liquid additives from storage containers to the blending unit or the well directly from the tank truck. Dry additives are poured by hand into a feeder system on the blending unit. The blended fracturing solution is immediately mixed with sand and pumped into the wellbore.

RETURN FLUIDS AND HYDROCARBONS AFTER COMPLETION OF FRACTURING

Once the fracturing procedure itself is completed, fluid returns to the surface in a process stage which is referred to as flowback. EPA (2010b) indicates that estimates of the flowback fluids recovered range from 15 to 80% of the volume injected depending on the site. Approximately 60% of the total flowback occurs in the first four days after fracturing and this may be collected as follows:

- unchecked flow through a valve into a lined pit,
- flow through a choke into a lined pit, and/or
- flow to tanks.

Storage of flowback water allows operators to re-use as much of it as possible for future fracturing operations. This would require dilution with freshwater and application of other treatment methods necessary to meet the usability characteristics.

A typical pit's volume may be 2,900m^3. Based on a pit depth of 3m, the surface footprint of a pit would be around 1,000m^2. Due to the high rate and potentially high volume of flowback water, additional temporary storage tanks may need to be staged onsite even if an onsite lined pit is to be used. Based on the typical pit capacity above, this implies up to around 20,000m^3 of additional storage capacity for flowback water from one fracturing operation on a single well (New York State 2009). In terms of overall flowback, water volume for a six well pad is suggested to be 7,900 to 138,000 m^3/pad for a single fracturing operation, with fracturing chemicals and subsurface contaminants making about 160-2,700m^3 (2%).

Fountain Quail Water Management of Jacksboro uses a recycling process which allows reuse of approximately 80% of the returned fracture fluids processed through its commercial mobile recycling unit. When water injected to fracture formations returns to the surface, it becomes unusable due to its high salt content. This recycling process involves on-site distilling units that apply heat to separate the brine resulting from fracturing gas formations into a relatively small volume of concentrated brine which is disposed of in a disposal well and a large volume of distilled water that can be re-used to fracture additional wells. Under this project, instead of hauling unusable return fracture fluids to a disposal well, the fracture flow-back fluid is stored in tanks on location and piped into treatment equipment. Natural gas produced on location is used to fire the distilling units that in turn boil the returned fracture fluid and produce distilled water. The distilled water can then be used to fracture treat another Barnett shale well.

SHALE GAS PRODUCTION FROM VARIOUS GAS FIELDS

There are a number of shale formations from which natural gas is being extracted throughout the USA, starting with the development of the Barnett Shale in Texas in 1980 and now including Antrim Shale in Michigan, New Albany Shale in Illinois and Indiana, Woodford Shale in Oklahoma, Fayetteville Shale in Arkansas, and Haynesville Shale in Louisiana. The total area of the Marcellus shale formation is roughly 246050km^2 but the Barnett field is about 12950 km^2 (US Department of Energy 2011).

The Barnett Shale

The Barnett shale is the first shale gas play to be commercially developed, which is the standard of comparison for this play type. In the Barnett in 1995 established the economic potential of US shale gas production and set the standard for subsequent development in other basins.

The estimated reserve in the Barnett shale is 0.28Tm^3. Horizontal drilling and fracting are the key enabling technologies which were first used to recover of Barnett shale gas economically in the mid-1990s. In 1997, the first slick water frac (or light sand frac) was performed successfully in the Barnett shale. At present there are 12,000 producing Barnett wells, of which $\frac{2}{3}$ are horizontal and $\frac{1}{3}$ are vertical. Total gas production is 159.71Bm^3 of which 102.51Bm^3 comes from horizontal wells and 57.2Bm^3 from vertical wells. Infills are being drilled and testing of spacing is down to 4.1ha, while re-fracturing of the first horizontal wells from 2003 and 2004 has commenced. Both infills and refracs are expected to improve estimated ultimate recovery from 11% to 18%. In addition to drilling longer laterals, current trends in the Barnett are toward bigger frac jobs and more

stages. There is a gulf of difference between initial production rates and ultimately recoverable reserves; the average lifetime of a well is much shorter than predicted before. From 2007 to 2009 the ultimately recoverable reserves of the Barnett shale decreased 30% from previously estimated, the average per well ultimately recoverable reserves fell from 35.11Mm^3 to 23.79Mm^3. The following figure-5 indicates that more than half a million acres (1 acre = 4,047m^2) under lease for exploration and development inside and outside the core area in the Barnett shale (Shale Gas 2005).

The Marcellus Shale

Marcellus is a Devonian-era shale, which means it originated approximately 350-415 million years ago stretching from western Maryland to New York, Pennsylvania and West Virginia and encompassing the Appalachian region of Ohio along the Ohio River. Experts estimate the Marcellus shale could contain as much as 13.9Tm^3 of natural gas, a level that would establish the Marcellus as the largest natural gas resource in North America and the second largest in the world (Wrightstone 2011).

The estimated natural gas in the Marcellus formation could warm homes and power industry for an entire generation (Ohio Business Development Coalition 2011). At that time a lot of algae and other organisms died and fell to the bottom of a sea that covered what is now the eastern half of the USA. These organisms provided carbon, which has since been converted into hydrocarbons, such as methane gas and crude oil (Sumi 2008).

The area encompassed by the Marcellus in the subsurface comprises about 13,9860km^2, which is slightly larger than Florida. Estimates for the recoverable reserves from the Marcellus shale are that it will produce about 13.9Tm^3. After completing drilling and fracking the production volumes in Marcellus well of New York State (New York State 2009) are given as follows:

- In year 1: Initial rate of 79.3Mm^3/day declining to 25.5Mm^3/day.
- In years 2 to 4: 25.5Mm^3/day declining to 15.6Mm^3/day.
- In years 5 to 10: 15.6Mm^3/day declining to 6.4Mm^3/day.
- In Year 11 and after: 6.4Mm^3/day declining at 3%/year.

Hence production is tails off significantly after 5 years. Then re-fracturing is needed to extend its economic life. When productive life of a well is over or unsuccessful wells are plugged and abandoned. Intervals between plugs must be filled with a heavy mud. For gas wells minimum 15m of cement must be placed in the top of the wellbore to prevent any release or escape of hydrocarbons or brine (waste water).

The Marcellus shale represents a stunningly large energy reserve and an opportunity for the Commonwealth of Pennsylvania to benefit from more than 100,000 new high paying jobs, direct payments of more than $600 billion to land owners in the form of bonus and royalty payments, and nearly a billion dollars in additional state and local taxes (figure-6). Yet, in spite of the positive economic benefits that will accrue to the state and its citizens, strong opposition has arisen against the development of this resource. Most of the opponents support their position based on claims of existing or possible environmental catastrophe and damage to existing roads and infrastructure. Others believe that the Marcellus development should only go forward after the enactment of a new severance tax on the resource (Arthur et al. 2008).

The Marcellus Shale – Appalachian Basin

Currently the hottest play in the 139,860km^2 in the Appalachian Basin, the Marcellus formation is not a new discovery. Prior to 2000, this low-density, vertically fractured shale formation was explored with a number of successful vertical gas wells, many of which have produced slowly but surely for decades.

The Marcellus shale ranges in depth from 1,220 to 2,590m, with gas currently produced from hydraulically fractured horizontal wellbores. Horizontal lateral lengths exceed 610m, and, typically, completions involve multistage fracturing with more than three stages per well (US Shale Gas 2008).

The Woodford Shale

Woodford shale stratigraphy and organic content are well understood, but due to their complexity compared to the Barnett shale, the formations are more difficult to drill and fracture. Because shales have the most elements and chemostratigraphic information to work with, they are more easily analyzed than most sandstone and carbonate reservoirs and can be chemosteered with unprecedented resolution using Laser Strat services. As in the Barnett shale, horizontal wells are drilled, although oil-based mud is used in the Woodford and the formation is harder to drill. In addition to containing chert and pyrite, the Woodford play is more faulted, making it easy to drill out of the interval; sometimes crossing several faults in a single wellbore is required. Halliburton geosteering techniques in combination with logging while drilling tools can minimize this risk. Like the Barnett shale, higher silica rocks are predominant in the best zones for fracturing in the Woodford play, although the Woodford has deeper and higher frac gradients.

Zone Seal cement has significantly improved the success rate to frac the shales, although acid and/or sand slugs are sometimes required to gain entry. Due to heavy faulting, 3-D seismic is extremely important, as the Woodford trends toward longer laterals exceeding 915m with bigger frac jobs and more stages. Testing infill pilots has begun, as well as some simultaneous-frac jobs. Pad drilling also will increase as the Woodford continues expanding to the Ardmore Basin and to West Central Oklahoma in Canadian County (US Shale Gas 2008).

The Bakken Shale –Williston Basin

The Bakken differs from other shale plays in that it is an oil reservoir, a dolomite layered between two shales, with depths ranging from around 2,438 to 3,048m. Each succeeding member of the Bakken formation; lower shale, middle sandstone and upper shale member is geographically larger than the one below. Both the upper and lower shales, which are the petroleum source rocks, present fairly consistent lithology, while the middle sandstone member varies in thickness, lithology and petrophysical properties. Currently, Bakken oil wells are completed either openhole or with uncemented liners, and the use of isolation tools such as Halliburton Delta Stim sleeves and Swellpacker systems is extensive. The Bakken is not as naturally fractured as the Barnett and, therefore, requires more traditional frac geometries with both longitudinal and transverse fractures. Diversion methods are used throughout hydraulic frac treatments, which primarily use gelled water frac fluids, although there is a growing trend toward the use of Intermediate Strength Proppant (US Shale Gas 2008).

The Fayetteville Shale – Arkoma Basin

With productive wells penetrating the Fayetteville shale at depths between a few hundred and 2,133m, this play is somewhat shallower than the Barnett. Mediocre production from early vertical wells stalled development in the vertically fractured Fayetteville, and only with recent introduction of horizontal drilling and fracking has drilling activity increased. As a result, at present there is less oilfield infrastructure in place in the Fayetteville than in other hot plays.

In the most active Central Fayetteville Shale, horizontal wells are drilled using oil-based mud in most cases, and water-based mud in others. Most wells now are cemented, but the current trend is toward using tools such as Halliburton's Delta Stim sleeves and Swellpacker systems technology in open-hole completions. In addition, 3-D seismic will gain importance as longer laterals of 914m are drilled and more stages are required for fracing. With growing numbers of wells and a need for more infrastructures, pad drilling is another trend emerging in the Fayetteville (US Shale Gas 2008).

Haynesville Shale

This gas field's prospective area is about 14,164Mm^2. Chesapeake energy discovered the Haynesville Shale in 2007; it is likely to become one of the two largest natural gas fields in the USA with about 2,064Mm^2. It is operating about 40 rigs in 2010 to drill about 190 wells. It produced about 14,158 Mm^3/day by year-end 2010 and about 19,538 Mm^3/day by end of 2011.

Chesapeake energy anticipates having an interest in roughly 80% of the wells drilled in the Haynesville and Bossier Core area which is concentrated in geologically stable areas where faulting and depth issues are minimized. It has 32.4ha spacing (8 wells per section) and 3,750 potential net wells to be drilled. Targeted average initial production rate 0.4 Mm^3/day and targeted ultimately recoverable reserves of 0.13-0.24 Bm^3 per well (US Shale Gas 2008).

The Haynesville Shale in East Texas / Northwestern Louisiana

Still in the early discovery stage, the Haynesville shale environment already has proved especially challenging. Compared to the Barnett, the Haynesville is extremely laminated, and the reservoir changes over intervals as small as four inches to one foot. In addition, at depths of 3,200 to 4,114m, this play is deeper than typical shales creating hostile conditions. Average well depths are 3,597m with bottomhole temperatures averaging 150^{0}C and wellhead treating pressures that exceed 10,000 psi. As a result, wells in the Haynesville require almost twice the amount of hydraulic horsepower, higher treating pressures and more advanced fluid chemistry than the Barnett and Woodford shales.

The high temperature range, from 127^{0}C to 193^{0}C, creates additional problems in Haynesville's horizontal wells, requiring rugged, high-temperature/high-pressure logging evaluation, Toolpusher and LWD tools. The majority of Haynesville leases are held for just three years, and with acreage leasing for up to $ 60976/ha, producers are concerned about their ability to drill in time (US Shale Gas 2008).

Durable high horsepower pumping equipment will be required to effectively fracture stimulate the Haynesville. Halliburton is positioned to provide the maximum horsepower necessary in these types of formations. Additionally, Halliburton's pump reliability is well established in the industry. The formation depth and high fracture gradient demand

long pump times at pressures above 12,000psi. Currently, Haynesville wells are being drilled with oil based mud, and as the trend continues toward increased activity, environmental issues will come to the fore. The estimated 115-plus rigs that will be drilling this play will require large volumes of water for fracturing, making water conservation and disposal a primary issue.

FUTURE PRODUCTION AND CONSUMPTION

EIA predict that overall annual energy consumption is projected to rise by 15% by 2035 with the main changes being in shale, bio-fuels and to a much lesser extent in renewables. The role of coal within the overall mix drops by only 1% by 2035 but actual consumption increases by 12% by the same year. EIA estimates the change of US primary energy source from 2008 to 2035 and is given briefly in table-2 (EIA 2010).

Table 2: The change in US primary sources from 2008 to 2035.

	US primary energy mix 2008	US primary energy mix 2035	% Change	% Increase in each energy source 2008 vs 2035
Coal	23%	22%	-1%	12%
Nuclear	9%	8%	0%	11%
Natural Gas (non-shale)	23%	17%	-6%	-13%
Shale Gas	2%	5%	4%	310%
Liquids	37%	33%	-4%	3%
Biofuels	1%	3%	3%	372%
Renewables	7%	11%	4%	88%
Total				**15%**

ADDITIONAL CH_4 EMISSIONS TO FRACKING

A typical well has 55 to 150 connections in the equipment of heaters, meters, dehydrators, compressors and vapor-recovery apparatus. Unfortunately many of them are leaks and vent gases. Among them pneumatic pumps and dehydrators are major parts of leakage (GAO 2010). On the other hand venting is visible during the liquid unloading. GAO (2010) estimated that 0.02 to 0.26% of total life-time. Sometimes CH_4 releases during *pipeline ready* without further processing. Also fugitive emission occurs during transport, storage and distribution of natural gas. It is estimated that in USA this type of emission is 0.53% and in Russia is 0.7% (Lelieveld et al. 2005). Howarth et al. (2011) estimated that a total loss during life cycle of an average shale-gas well, 3.6% to 7.9% of the total production of the well is estimated to atmosphere as CH_4. It is at least 30% more than conventional gas.

Russia and USA apply direct inspection and maintenance programmes both for substantial CH_4 emissions reductions and gas savings. In 2007, US domestic partners reduced CH_4 emissions by 2.62 Bm^3, which saved approximately $ 650 million to natural gas sales. CH_4 is produced and emitted during the anaerobic decomposition of organic material in livestock manure mainly from swine, cattle and poultry operations. In 2008, US farm digester system produced an estimated 290,000 MWh (Million watt-hours) equivalents of energy generation. CH_4 management contributes approximately 4% of the total anthropogenic CH_4 emissions. Global CH_4 emissions from manure management are

projected to increase 21% between 1990 and 2020 (EPA 2006). CH_4 from manure can be recovered using anaerobic digesters, including covered lagoons, plug flow digesters, complete mix digesters and small scale digesters (M2M 2008). These types of CH_4 mitigation technologies are costly and most countries do not aware of these. So that proper education is needed with financial support to CH_4 mitigation in manure preparation projects (Mohajan 2012).

COMPARISON BETWEEN INITIAL STOCK AND PRODUCTION RATE OF GAS

The estimated measure of gas in a reservoir and consequently reserves is expected to vary from site to site. The UK Department of Energy and Climate Change (DECC 2010) measurement of various gas fields of USA are given in table-3.

Table 3: Comparison between initial stock and production rate of gases of the USA.

Gas shale basin	Gas initially in place	Reserves	Estimated production
	Bm^3	Bm^3	m^3/well/day
Barnett	9,260	1,250	9,571
Faylleville	1,470	1,180	15,008
Haynesville	20,300	7,110	34,349
Marcellus	42,500	10,300 -1,4200	87,783
Woodford	1,470	323	11,752
Antrim	2,150	566	4,616

ADVANTAGES IN SHALE GAS PRODUCTION

In the USA, the UK and elsewhere shale gas will be a substitute of more carbon intensive fuels such as coal in electricity generation. So that expansion of shale gas production will provide low carbon economy, therefore it is a positive side of low greenhouse gas (GHG) emissions in the atmosphere and considering the benefit sides it has been referred to as a *bridging fuel*. National gas as a transitional fuel, allowing continued dependence on fossil fuels yet reducing GHG emissions compared to coal or oil over coming decades (Pacala and Socolow 2004).

Developing domestic natural gas resources create additional jobs when wells are drilled, pipelines are constructed, and production facilities are built and operated. In addition, higher volumes of available domestic natural gas mean lower fuel for industries that use natural gas to process or manufacture products. This means fewer jobs lost to lower-cost overseas competitors, as well as lower prices for consumers. Shale gas production also means increased tax and royalty receipts for state and federal government, and increased economic activity in producing areas from royalty and bonus payments to landowners. This influx of revenue can be used to enhance public services (US Department of Energy 2011).

GHG emissions from gas are lower than from coal, but are still much higher than many low-carbon technologies such as nuclear, solar or wind power. CH_4 is far more potent than carbon dioxide, but CH_4 would only be released through leaks from the well or pipelines and this can be easily minimized through regulation and enforcement.

DISADVANTAGES

The Council of Scientific Society Presidents (CSSP 2010) wrote to the US President Obama, warning that shale gas has received insufficient analysis and may aggregate rather than mitigation of global warming. In 2010 the EPA issued a report that fugitive emissions of methane from unconventional gas may be for greater than for conventional gas (EPA 2010a).

Contamination of the Water Supply

Although potential GHG benefits of shale gas, the drilling and fracking technologies impose a negative environmental impacts and risks. A huge amount of water is used in fracking which may deplete local ecosystems. In fracking process chemicals and water are used, the mixture eventually returns to the surface which may contaminate both land and water. The waste water produced by fracking contains at least 29 chemicals that are known to cause or strongly suspected of causing cancer. The mixture consists of carbon dioxide, hydrogen sulfide, mercury, arsenic and lead, naturally occurring radioactive materials such as radium, thorium, uranium and the BTEX compounds-benzene, toluene, ethylbenzene and xylene (US Houses of Representatives Committee on Energy and Commerce Minority Staff 2011). Due to the contamination of these chemicals drinking water turn to be brown and people become sick which sometimes strongly suspected to cancer, and domestic animals may lose their hair.

When shale-gas is extracted from organic-rich shales in USA and elsewhere in such processes, methane is contaminated in drinking water. No doubt we find benefits for such extraction (Osborn et al. 2011) but contaminated drinking water with CH_4, which is harmful for health. If there are one or more gas wells within 1km then average and maximum concentrations of methane in drinking water wells increased and it reaches about 19.2 and 64mgL^{-1} respectively (Mohajan 2012). In Susquehanna County, Pennsylvania alone, approved gas-well permits in the Marcellus formation increased 27-fold from 2007 to 2009 (Pennsylvania Department of Environmental Protection, Bureau of Oil and Gas Management 2010).

Air Pollution Due to Fracking

During the gas exploration and production activities some air pollution emissions, for example, oxides of nitrogen (NO_x), volatile organic compound such as benzene, sulphur dioxide (SO_2) and CH_4 commonly emit. NO_x gases create brown haze around areas of gas field which causes acid rain, the destruction of lake ecosystems and the formation of ozone smog. These emissions due to fracking in shales have been related to illness and death (US Energy Independence with Environmental Costs 2010). In 2010, US EPA has launched a new review of the practice known as fracking on Dish of Texas and similar sites from Colorado to Wyoming. The team collected seven samples near the gas fields and found that benzene was present at levels as much as 55 times higher than allowed by the Texas Commission on Environmental Quality. Similarly, xylene and carbon disulfide (neurotoxicants), along with naphthalene (a blood poison) and pyridines (potential carcinogens) all exceeded legal limits, as much as 384 times levels deemed safe. Residents of Texas communities near hydraulic fracturing gas extraction operations have reported strange odors and health problems including nose bleeds, rashes, burning eyes, breathing difficulty, asthma, dizziness, fatigue, nausea, muscle aches, severe headaches

and blackouts. Several residents have developed rare cancers (US Department of Energy 2011). Sometimes air is pullulated from vehicle emissions, safety flares, gasoline or diesel powered generators and pumps, and oil/gas separation and storage tanks (US Energy Independence with Environmental Costs 2010).

The Noise Pollution

According to the Ohio Department of Natural Resources, excessive noise is the top complaint filed by people living near drilling sites. Noise comes from traffic, from the drilling site as well as from the drilling process. While a nuisance, the problem is usually short-term although some people have complained of noise even after wellhead completion. Many energy companies, particularly those with experience drilling in highly-populated areas, use sophisticated sound barriers to curb the problem, but may not do so unless required (Stark Development Board 2011).

Damage of Roads

During fracking the excess trafficking damages roads. The energy companies sometimes voluntarily repair roads. These agreements generally state that the energy company will pay for any unscheduled road maintenance and repairs needed due to excess drilling traffic but not all the companies do so (Stark Development Board 2011).

Effects on Climate Change

Although natural gas, when burned, produces only about half of the carbon dioxide emissions of coal, that calculation omits GHG emissions from the well-drilling, water-trucking, pipeline-laying, and forest-felling which are part of the production of fracking shale gas. Combining the effects of combustion, production, distribution, and leaked methane from hydraulically fractured natural gas gives the fuel about the same GHG emissions as coal and about 30% more than diesel or gasoline (Howarth 2011).

CONCLUDING REMARKS

In this paper we have discussed the process of extraction of unconventional shale gas. Continual increase of demand of natural gas conventional extraction can not provide sufficient supply of natural gas, so that unconventional shale gas extraction increases in the USA, the UK and elsewhere. Methane, the main element of shale gas emits low carbon than the coal and oil do and decreases GHG emissions in the atmosphere. Although fracking is beneficial for environment due to low carbon emission but it contaminates drinking water and pollutes air.

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