Project Acronym and Title:

M4ShaleGas - Measuring, monitoring, mitigating and managing the environmental impact of shale gas

REVIEW OF SHALE GAS WELL DRILLING, COMPLETION, PRODUCTION AND ABANDONMENT OPERATIONS

Authors and affiliation:

Kamila Gawel[1], Alexandre Lavrov[1], Malin Torsæter[1]*

[1]SINTEF Petroleum Research, Trondheim, Norway

E-mail of lead author(*):

malin.torsater@sintef.no

Project deliverable number: D5.1

Status: Definitive

Disclaimer

This report is part of a project that has received funding by the *European Union's Horizon 2020 research and innovation programme* under grant agreement number 640715.

Published November 2015 by M4ShaleGas Consortium

Public introduction

M4ShaleGas stands for *Measuring, monitoring, mitigating and managing the environmental impact of shale gas* and is funded by the *European Union's Horizon 2020 Research and Innovation Programme*.
The main goal of the M4ShaleGas project is to study and evaluate potential risks and impacts of shale gas exploration and exploitation. The focus lies on four main areas of potential impact: the subsurface, the surface, the atmosphere, and social impacts.
The European Commission's Energy Roadmap 2050 identifies gas as a critical fuel for the transformation of the energy system in the direction of lower CO_2 emissions and more renewable energy. Shale gas may contribute to this transformation.
Shale gas is – by definition – a natural gas found trapped in shale, a fine grained sedimentary rock composed of mud. There are several concerns related to shale gas exploration and production, many of them being associated with hydraulic fracturing operations that are performed to stimulate gas flow in the shales. Potential risks and concerns include for example the fate of chemical compounds in the used hydraulic fracturing and drilling fluids and their potential impact on shallow ground water. The fracturing process may also induce small magnitude earthquakes. There is also an ongoing debate on greenhouse gas emissions of shale gas (CO_2 and methane) and its energy efficiency compared to other energy sources
There is a strong need for a better European knowledge base on shale gas operations and their environmental impacts particularly, if shale gas shall play a role in Europe's energy mix in the coming decennia. M4ShaleGas' main goal is to build such a knowledge base, including an inventory of best practices that minimise risks and impacts of shale gas exploration and production in Europe, as well as best practices for public engagement.
The M4ShaleGas project is carried out by 18 European research institutions and is coordinated by TNO-Netherlands Organization for Applied Scientific Research.

Executive Report Summary

This report summarizes the most common procedures for shale gas well drilling, completion, production and abandonment. Information has been gathered from peer-reviewed scientific literature, available standards/guidelines and from research reports. The aim of the report is to answer the following questions:

- What are the procedures used for drilling, cementing and completing shale gas wells?
- How is gas produced – and do production operations affect well integrity?
- How are shale gas wells permanently plugged and abandoned after use?

In addition to describing procedures, the report wraps up with a short discussion of the environmental impact of the various well operations.

TABLE OF CONTENTS

Page

1 INTRODUCTION

1.1 Context of M4ShaleGas

Shale gas source rocks are widely distributed around the world and many countries have now started to investigate their shale gas potential. Some argue that shale gas has already proved to be a game changer in the U.S. energy market (EIA 2015[1]). The European Commission's Energy Roadmap 2050 identifies gas as a critical energy source for the transformation of the energy system to a system with lower CO_2 emissions that combines gas with increasing contributions of renewable energy and increasing energy efficiency. It may be argued that in Europe, natural gas replacing coal and oil will contribute to emissions reduction on the short and medium terms.

There are, however, several concerns related to shale gas exploration and production, many of them being associated with the process of hydraulic fracturing. There is also a debate on the greenhouse gas emissions of shale gas (CO_2 and methane) and its energy return on investment compared to other energy sources. Questions are raised about the specific environmental footprint of shale gas in Europe as a whole as well as in individual Member States. Shale gas basins are unevenly distributed among the European Member States and are not restricted within national borders, which makes close cooperation between the involved Member States essential. There is relatively little knowledge on the footprint in regions with a variety of geological and geopolitical settings as are present in Europe. Concerns and risks are clustered in the following four areas: subsurface, surface, atmosphere and society. As the European continent is densely populated, it is most certainly of vital importance to understand public perceptions of shale gas and for European publics to be fully engaged in the debate about its potential development.

Accordingly, Europe has a strong need for a comprehensive knowledge base on potential environmental, societal and economic consequences of shale gas exploration and exploitation. Knowledge needs to be science-based, needs to be developed by research institutes with a strong track record in shale gas studies, and needs to cover the different attitudes and approaches to shale gas exploration and exploitation in Europe. The M4ShaleGas project is seeking to provide such a scientific knowledge base, integrating the scientific outcome of 18 research institutes across Europe. It addresses the issues raised in the Horizon 2020 call LCE 16 – 2014 on *Understanding, preventing and mitigating the potential environmental risks and impacts of shale gas exploration and exploitation.*

[1] EIA (2015). Annual Energy Outlook 2015 with projections to 2040. U.S. Energy Information Administration (*www.eia.gov*).

1.2 Study objectives for this report

Underground reservoirs of hydrocarbon resources are usually accessed through *wells*, also known as wellbores, boreholes or simply holes. Technological advances related to drilling and well technology, especially horizontal drilling and hydraulic fracturing, are the main reasons shale gas resources have become competitive on the energy market. Wells also represent man-made "tunnels" of cement and steel that connect shale reservoirs with the atmosphere. They are thus important both for cost-efficient production and for environmental safety related to shale gas exploitation. In fact, recent studies have pointed out that *improper well construction and plugging is the greatest environmental threat* towards safe shale gas production (Gold, 2012, Darrah et al., 2014, Davies et al., 2014). A recent report on shale gas extraction in the UK has also pointed out that *well integrity is of highest priority for safe shale gas recovery* (RoyalSociety, 2012).

The typical life-cycle of a shale gas well is summarized in Fig. 1, giving an overview of important well operations. In the present report, the aim is to outline how shale gas well drilling, completion, production and abandonment operations are performed today. Since commercial scale shale gas exploitation is at present limited to North America, the report focuses on procedures typically performed there. Where relevant, references are made to standards and available "best practices" documents. The report provides a general overview of the well operations, and points out shale gas specific well issues.

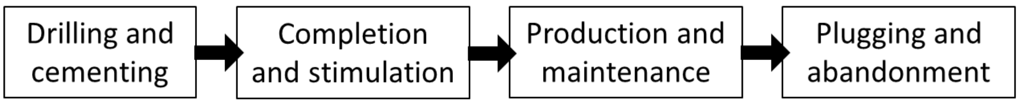

Figure 1 An overview of important shale gas well operations.

1.3 Aims of this report

The report is a public dissemination summarizing the procedures performed during shale gas well drilling, completion, production and abandonment. It draws upon published scientific literature, standards and best practices, mainly from North America, since this is the most mature shale gas region today.

2 SHALE GAS WELL DRILLING AND CEMENTING

2.1 General overview

Like conventional oil and gas wells, shale gas wells are constructed by cementing in place casing strings of progressively smaller diameter as the well gets deeper. This gives the well a "telescopic" structure, and is done in order to support the borehole wall and prevent formation fluid influx into the upper parts of the well (see Fig. 2). The number of casing strings, their lengths and rules for cementing them in place are determined by local geology at the site. A common goal is, however, to always isolate groundwater and potential flow zones.

Shale gas wells often include a horizontal section, meaning that the well direction is changed from vertical to horizontal when the reservoir is reached. This enables production from larger sections of the reservoir, and it enables accessing difficult locations, e.g. those located under surface aquifers or mountains. Building well inclination requires that the drill string used to drill the vertical section of the well is pulled out of the hole, and a specialized drill string enabling deviated well drilling is run in the hole. Steerable motors or rotary steerable systems are currently used to drill the deviated parts of the wells. Operated by skilled navigators, such systems allow full control of the well trajectory, whereby the targeted parts of the reservoir can be reached, while troublesome zones can be avoided during drilling.

2.2 Drilling

2.2.1 Gas shale geological aspects

Shale gas reservoirs are source rocks where hydrocarbons were generated. They are often *naturally fractured,* and one of the goals during drilling is to intersect as many fractures as possible in order to maximize well productivity. For instance, the Marcellus shale in the US contains numerous vertical fractures, and to intersect them it is necessary to perform horizontal drilling (Agbaji et al., 2009).

Another observation frequently made about gas-bearing shales is that their composition, geological history and properties change significantly from one basin deposit to another. For instance, four types of shale gas reservoirs have been identified in the US alone (Wylie, 2012): (1) fractured organic shale with high carbonate content (e.g. Barnett); (2) laminated sands embedded in organic-rich shales (e.g. Bakken); (3) organic-rich black shale (e.g. Marcellus); (4) a combinations of (1) to (3) (e.g. Niobrara). The variability of shale properties calls for a detailed characterization and testing of each specific shale play before drilling and production can commence.

Even if shales differ from site to site, drilling in them is generally difficult, as they contain clays that may interact with the drilling fluid. They are also anisotropic rocks with pronounced weakness planes, and they have low permeability – which often results in elevated pore pressure. Extensive experience has been gathered while drilling through shale cap rocks, e.g. in the North Sea, but it should be noted that these shales may be quite different from gas-bearing shales. In particular, gas-bearing shales may have lower clay contents than cap rock shales, and have higher percentages of other minerals. For instance, the Eagle Ford shale has 55% calcite and only 8% clay content. Bedding planes and natural fractures play significant role in reducing the rock strength and borehole stability in shales (Guo et al., 2012). Gas shales are typically stronger, less reactive and more brittle than typical cap rock shales e.g. in the North Sea. Nevertheless, drilling in cap rock shales has supplied invaluable experience for efficient exploitation of shale gas reservoirs – and decades of shale drilling and development in the US have expanded the knowledge base further.

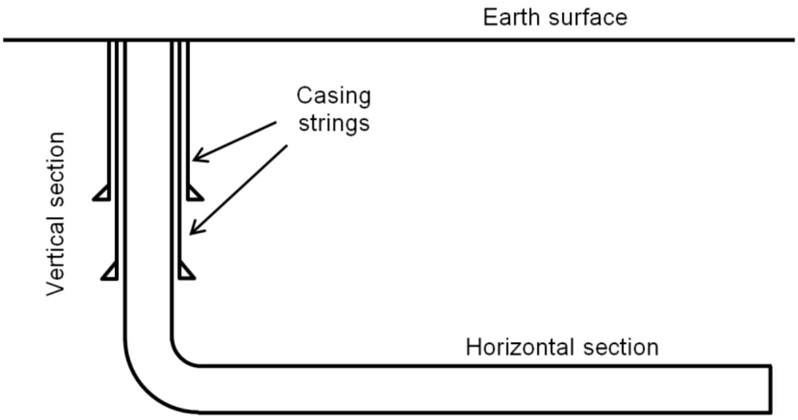

Figure 2 Wellbore with a horizontal section (not to scale).

2.2.2 Choice of drilling mud

When drilling a well, drilling fluid is usually pumped from the surface down the drill pipe. The fluid exits through drill bit nozzles, and returns back to surface via the annulus between the drill string and the formation (or casing, higher up the well). A schematic illustration of the concept is given in Fig. 3. This circulation system, known as "direct circulation", is the most common in oil and gas industry – and also for shale wells. On the way back to surface, the drilling fluid carries drill cuttings and is usually referred to as "drilling mud". On the surface, the cuttings are separated from the drilling fluid by shakers, centrifuges and hydrocyclones. "Recycled" drilling fluid free of cuttings is then pumped back into the well. Since perfect separation of cuttings is not possible, the composition and properties of a drilling fluid gradually change and need to be adjusted. For instance, it might in many cases be necessary to make the fluid "thinner" (less viscous) if the viscosity went up because of fines accumulation in the fluid.

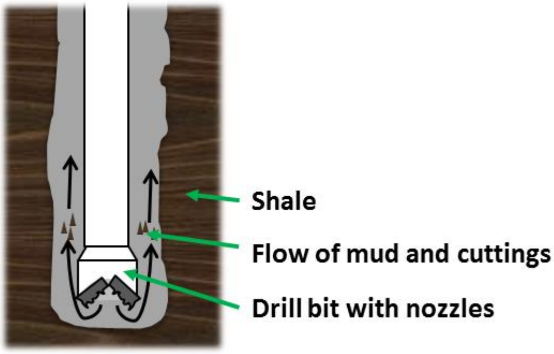

Figure 3 Illustration of a drill string with bit drilling through shale. Flow of mud and cuttings up the annular space between the drillstring and the borehole is indicated.

The drilling fluid has the following functions: (1) maintain fluid pressure in the well to prevent influx of formation fluids; (2) maintain pressure on the borehole wall to prevent hole collapse and instabilities; (3) cool and lubricate the drill bit; (4) transport cuttings to surface. The importance of the first of these functions becomes clear when taking into account that the formation is fluid-saturated. The formation fluid will flow into the well unless the fluid pressure in the well is equal to or greater than the formation fluid pressure (also known as the "pore pressure"). One usually tries to avoid fluid influx into the well since it may get out of control. If the formation fluid is gas, as in shale gas reservoirs, the influx may represent a serious drilling hazard since the gas expands as it travels up the vertical section of the well. If not handled properly, such an influx may turn into a so-called "kick", with economic, environmental and safety consequences.

Drilling for oil- and gas is generally performed with water-base fluids, usually referred to as WBM (water-base mud), or non-aqueous drilling fluids. Sometimes air drilling is used to drill the first few thousand feet in shale gas plays. However, increase in the pore pressure gradient at greater depths usually necessitates switching to an all-liquid fluid, i.e. WBM or non-aqueous (Agbaji et al., 2009). The distinction between water-base and non-aqueous drilling fluids is based on the type of the continuous phase, which is water in WBM and can be e.g. mineral oil or diesel oil in non-aqueous fluids. Non-aqueous fluids include oil-base muds (OBM) and synthetic-base muds (SBM). The holes are usually spudded with WBM, and WBM is used to drill the surface hole section in loose, unconsolidated sands. Oil-base muds are then used to drill to the target depth in shale. For instance, most of the horizontal wells in the Eagle Ford shale (Texas) have been drilled with OBM (Guo et al., 2012). The use of OBM reduces the drilling time compared to WBM since non-productive time caused by shale instabilities is reduced. Moreover, the use of OBM reduces bit balling caused by cuttings stuck to the drill bit. However, relatively high costs and environmental issues associated with OBM and other non-aqueous fluids have made shale operators in the US move towards more frequent use of WBM in the recent years, at least in some basin deposits(Wylie, 2012).

The choice of mud during shale gas drilling must always ensure good hole cleaning (transport of cuttings out of the hole and up to surface). Poor hole cleaning leads to cuttings accumulation at the bottomhole assembly, which in the worst case may result in the drill string getting packed off and stuck in the well. Flat-rheology drilling fluids can also be beneficial, as they are less affected by being heated up when new pipe is being added to the drillstring and pumps are turned off. If the mud builds up gel strength when there is no circulation in the well, an elevated pressure needs to be applied to break the gel when re-starting circulation. This can cause damage to the borehole wall and loss of drilling mud into the formation.

2.2.3 Typical drilling problems

Drilling a hole several thousand meter deep naturally involves certain risks in terms of *borehole stability* and *loss of drilling fluid into the formation*. During drilling, an attempt is usually made to maintain the bottomhole pressure (BHP) within the so-called "drilling window" or "operating pressure window". The lower limit of this window is determined either by the formation pore pressure or the borehole stability limit, whichever is greater. If the BHP drops below the formation fluid pressure, formation fluid influx may start. If the BHP drops below the value given by borehole stability considerations, failure may start on the borehole wall. Failure at the wall usually happens either in form of symmetric breakouts, or a uniform reduction in the hole cross-section. The failure *per se* does not necessarily mean that the well is lost. It may, however, lead to other issues such as tight hole, pack-off of the drill string, and stuck pipe. These problems require special measures such as reaming and hole enlargement that entail non-productive time and increase the drilling costs. In the worst case, these problems may cause loss of equipment or forced sidetracking of the wellbore.

Borehole instabilities are usually exacerbated in shales as compared to other rocks (e.g. sandstones), especially when drilling with water-base muds. For this reason, non-aqueous fluids, e.g. oil-base muds, are often a preferred choice in shales (Guo et al., 2012). Additionally, borehole instabilities in shales are aggravated by shale anisotropy caused by bedding planes. Especially deviated and horizontal wells drilled in shales are prone to instabilities. The drilling window may shrink dramatically with the well inclination. Extensive expertise in horizontal drilling accumulated over decades in the oil industry (e.g. deepwater extended reach drilling wells) can be and is exploited in order to reduce drilling problems and minimize drill time of directional wells in gas-bearing shales.

The upper limit of the operational BHP window is determined by the fracturing pressure. If the pressure exceeds the upper limit of the BHP window (the so-called "fracture gradient"), fluid can be lost into the formation. This is called "mud loss" or "lost circulation", and has a number of negative consequences, in addition to the obvious loss of an expensive fluid. In particular, if the losses are so severe that the fluid column in the annulus cannot be maintained, the mud loss incident may lead to formation fluid influx in the upper part of the open hole. Moreover, drilling fluid is typically loaded with solid particles (being either a part of the original drilling fluid formulation, or drill cuttings). These particles may block formation pores and fractures creating the so-called "formation damage" that may impair the future productivity of the well. Finally, losses, if not properly cured, indicate a potential escape pathway for cement during subsequent cementing of the well. Since the apparent viscosity and density of the cement are normally greater than those of the drilling fluid, a formation that experienced losses during drilling is likely to experience losses during cementing. This is likely to result in poor cementing quality, and, consequently, jeopardize the well integrity.

Many shale gas formations, e.g. the Barnett Shale or the Niobrara Shale in the US, contain fracture systems that are essential for production from these reservoirs (Wylie, 2012). Drilling in such formations, however, is likely to induce mud losses if the bottomhole pressure exceeds the formation pore pressure by some margin. In addition to natural fractures, a well being drilled in a shale gas reservoir that is already in production may inadvertently intersect a hydraulic fracture previously induced from another well. Knowing the location, orientation and dimensions of hydraulic fractures may aid in designing the well paths that avoid such fractures.

2.2.4 Avoiding drilling problems in shales

Solutions usually employed in oil and gas industry to prevent mud losses are as follows: (1) identification of loss zones at well planning stage; (2) management of the bottomhole pressure so as to stay within the drilling window; (3) good hole cleaning; (4) underbalanced drilling; (5) managed pressure drilling; (6) use of loss prevention materials (LPM) and wellbore strengthening. Even though detailed information about in-situ conditions (e.g. fracture density and apertures) is rarely available before a well is spudded, it is sometimes possible to identify potential trouble zones before drilling commences. For instance, zones around faults often are heavily fractured, while the rocks themselves are weaker than the surrounding formations. In addition, principal in-situ stresses often change orientation near the fault. All these factors have an influence on borehole stability and, in particular, may induce losses while drilling through or near faults. Geomechanical modeling may help in predicting stresses in and around reservoirs and thereby provide constraints on the maximum mud weight when drilling these rocks.

If potential loss zones have been identified at the well planning stage, preventive measures can be implemented. Management of the bottomhole pressure, or equivalent circulating density (ECD), is a reliable way to avoid drilling problems such as lost circulation, fluid influx and borehole instability. In theory, it should be possible to adjust ECD either by controlling the mud weight with weighting agents (such as barite or hematite), or by pump rate control. Reducing the pump rate decreases the annular pressure loss and thereby the ECD. Unfortunately, it impairs the cuttings transport and may therefore increase the mud weight in the annulus and thus counteract the intended ECD reduction. Another problem with ECD reduction, particularly relevant for shale gas reservoirs, is due to heterogeneous pore pressure distribution *in situ*. Shales, due to their extremely low matrix permeability, are often over-pressured, i.e. their pore pressure is above the hydrostatic value. Sands located in the same interval may well be under-pressured or normally-pressured. Situations are not uncommon where the fracture gradient in sand is near the pore pressure in the adjacent shale. Under such circumstances, it is physically impossible to choose a mud weight that would be within the drilling window of both rocks. In deepwater drilling, mud losses are often considered less dangerous than a kick (Gradishar et al., 2014). For this reason, in deepwater drilling operations, a decision may be taken to drill above the fracture gradient in the under-pressured formation, and thus proceed with losses that can be handled with a lost circulation material (LCM). LCM is a particulate material that can be added to the drilling fluid in order to plug fractures and pores when losses are encountered. In shale gas, on the other hand, the rock permeability is low, which may mitigate the influx to the well if the ECD is below the pore pressure, while losses would damage the fracture permeability and thus adversely affect future well productivity. Following this strategy, underbalanced drilling (UBD) is commonly used while drilling for shale gas (Ridley et al., 2013b).

Underbalanced operation and Managed pressure drilling. A glossary compiled by the International Association of Drilling Contractors (IADC) defines underbalanced drilling (UBD) as follows: "A drilling activity employing appropriate equipment and controls where the pressure exerted in the wellbore is intentionally less than the pore pressure in any part of the exposed formations with the intention of bringing formation fluids to the surface". UBD is achieved by introducing gas into the drilling fluid. The drilling fluid may thereby be pure air, mist, foam or an aerated mud. UBD reduces or eliminates mud losses, reduces formation damage, reduces or eliminates differential sticking, and improves the rate of penetration. On the downside, UBD may induce borehole instability problems and formation fluid influx. Formation fluid influx may pose a problem especially if it brings H_2S to the surface. Borehole instabilities may result in cavings accumulation in the annulus, i.e. poor hole cleaning. Finally, mud-pulse telemetry (transmitting log data by fluid pressure pulses from the bottomhole to the drilling rig) does not work in all-gas and gas-liquid systems.

Also managed pressure drilling (MPD) is sometimes used when drilling in shales. This is defined as "an adaptive process used to precisely control the annular pressure profile throughout the wellbore", according to the UBO & MPD Glossary compiled by the International Association of Drilling Contractors (IADC). At present, MPD is a collection of drilling techniques that are designed to enable drilling with narrow windows and drilling in formations with significantly varying fracture and pore pressure gradients. Without resorting to MPD, drilling in such formations would necessitate extra casing points, which entails extra costs during drilling and has a negative impact on well productivity by reducing the well diameter at the target depth. In the following, examples of MPD methods are outlined (Rehm et al., 2008):

- *Constant bottomhole pressure drilling.* This implies that the bottomhole pressure is adjusted, e.g. by applying backpressure on the annulus, and kept static near the lower limit of the operating BHP. Constant bottomhole pressure drilling is particularly effective in formations with narrow drilling windows. The method enables the driller to avoid/mitigate mud losses or formation fluid influx that otherwise would occur when the pressure varies. Software control can be used for full compensation of pressure variations downhole. The use of backpressure to manipulate the bottomhole pressure requires that a rotating control device is installed above the blowout preventer. The device diverts the flow to another extra piece of equipment needed for backpressure control, namely a choke manifold. The need for modifications to the rig equipment is the downside of constant bottomhole pressure drilling as well as most other MPD techniques. Other downsides are the extra space required for the extra equipment and the extra training required for the rig personnel. In addition, the extra equipment involves higher risk of hardware failure or malfunction. The advantage of this technique is precise control of the bottomhole pressure.

- *Mud-cap drilling.* Floating mud-cap drilling is a method where the hole is drilled with no returns, i.e. all drilling fluid is lost into the fractures. Water can be used as such sacrificial fluid, and the mud level in the annulus is allowed to "float". Pressurized mud-cap drilling implies that a column of light mud is held in the annulus. Sacrificial drilling fluid is pumped down the drill string while some annular pressure is applied at the surface. In both variations of mud cap drilling, the bottomhole pressure is approximately in balance with the reservoir pressure. Mud cap drilling is particularly effective in fractured and/or vugular formations where total losses are experienced. Instead of combatting the problem, losses are allowed, but the fluid lost into the formation is an inexpensive sacrificial fluid. Extra equipment required for these methods is minimal. Downsides of mud cap drilling include formation damage and the need for large volumes of the sacrificial fluid.

- *Dual-gradient drilling.* This method is sometimes used in deepwater wells where, in conventional drilling, mud in the marine riser would create bottomhole pressure in excess of the fracture pressure. In this technique, a subsea mudlift pump is installed on the seafloor to pump the return mud to the platform. The pump equalizes the annular pressure with the hydrostatic pressure of the seawater at that location. In onshore shale-gas drilling, dual density systems involve simultaneous use of higher mud weight in shale and lower mud weight in the upper sands. This prevents influxes in shale without fracturing the overlying sand (Ridley et al., 2013a).

A last preventive measure against lost circulation is the use of loss prevention materials (LPM). These are typically particulate materials that are continuously circulated when drilling a potential loss zone. In contrast to LCM, loss prevention materials are introduced beforehand rather than when significant losses are already occurring. LPM plugs the fractures and thereby "strengthens the wellbore". An example of successful drilling in a challenging shale gas reservoir with low-pressure sands and over-pressured shales was described in (Ridley et al., 2013b). LPM was introduced in the drilling fluid when drilling through the Olmos sand prone to losses, while the mud weight was kept close to the fracture gradient of this rock.

2.3 Cementing

After an interval has been drilled, the drill string is pulled out of the hole, and the casing string is run into the hole. Once the casing is in place, the drilling fluid is displaced from the casing by pumping a sequence of fluids down the casing, the last of which is cement. The fluids travel down the interior of the casing, exits at the casing shoe and travel up the annulus between the casing and the formation (or the previously installed casing, if the planned top of cement is above the shoe of the latter). After the cement placed in the annulus has hardened, the drill string is lowered into the hole, now with a smaller-diameter drill bit, and drilling is continued. The procedure is then repeated when the end of the next interval is reached. This process is continued until the target depth of the well is reached. The resulting well structure looks like a telescopic arrangement of casing pipes of progressively smaller diameter. A cemented well with a cemented horizontal section is depicted in Fig. 4.

The main functions of annular cement are as follows: (1) to hold the casing pipes in place; (2) to enable circulation while drilling the next interval; (3) to reduce detrimental effects of corrosive formation fluids on the casing; (4) to provide zonal isolation by preventing fluid flow between horizons up or down the annulus. The last function is of paramount importance not only during service time of the well, but also after the well is plugged and abandoned. High quality of annular cement is required to prevent leakage of hydrocarbons to higher horizons where they might accidentally enter aquifers or exit to surface. High quality of cementing implies that there be no gas channels, undisplaced mud (mud pockets) or other defects left in the annulus. Ideally, the drilling fluid should be evenly displaced from the annulus by spacers, and then the spacers should be evenly displaced by cement without leaving any fluids behind.

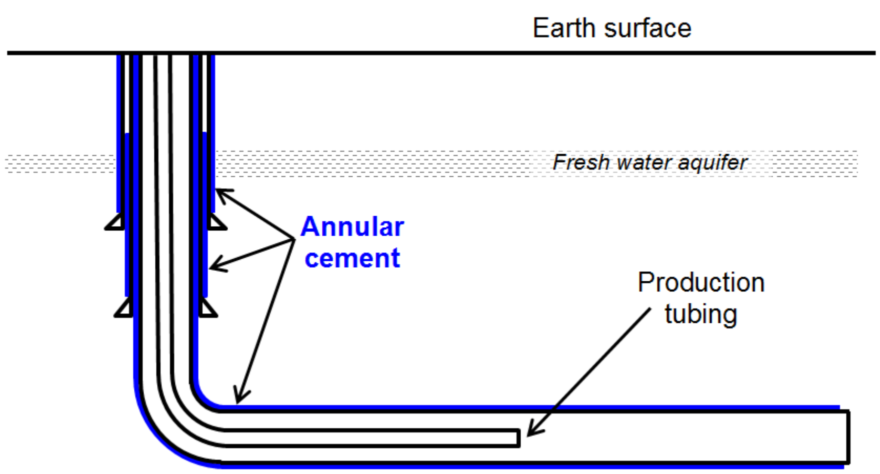

Figure 4 Cemented well with a cemented horizontal section (not to scale).

Flow channels can form in cement as it is pumped up the annulus if the fluid in place (spacer/mud) is not properly displaced. Usually this is caused by eccentric positioning of the casing string in the well. Cement tends to flow along the side of the casing that has the largest clearance towards the formation. Mud and spacer displacement on the narrow side will, in contrast, be impaired. The problem of casing eccentricity is exacerbated in deviated and horizontal wells. In addition, action of the drill string and mud during drilling may create uneven borehole walls. This will later be detrimental for cement placement in the annulus. Also breakouts, i.e. symmetric enlargements of the borehole cross-section caused by rock failure due to in-situ stresses, can be detrimental for achieving good annular cement jobs. Assessment of cementing quality after the cement has hardened is therefore crucial and is usually done by means of cement bond log (acoustic sensing of the bonding between cement and casing) or temperature log (enables locating the top of annular cement) or other methods.

The primary goal of all well cementing operations is to establish *zonal isolation*, which implies hindering leakage between different subsurface strata. Poor zonal isolation may result in leaking wells and contamination of aquifers. Loss of zonal isolation was identified as one of the troubles in some of the wells drilled in the Marcellus shale (Watters, 2012). Poor cement placement can be a threat towards zonal isolation, as described above, but also poor cement bonding to casing/rock can create leakage pathways (Nelson and Guillot, 2006). This is typically occurring if cleaning of casing/rock surfaces prior to cement pumping was insufficient. In addition, debonding may occur because cement shrinks as it sets. Debonding may result also from mechanical and thermal loads applied to the well during its lifetime, causing "long-term zonal isolation loss" (Watters, 2012).

Since it is hardly conceivable that a perfectly circular borehole is always created when drilling for shale gas, and since cementing is often done with eccentric casing, techniques and technologies have been developed aiming to improve or repair imperfect cement sheaths. For instance, swellable rubber sheaths attached to casing are used for remediating microannuli and poorly cementing zones, such as those caused by eccentric casing (Watters, 2012). In addition to channels caused by less-than-optimal cement placement, channels in cement may develop via gas migration as cement sets. During setting, cement undergoes a transition from a slurry to a solid. In this process, cement develops shear and tensile strengths, and it may also shrink unless special measures are taken to prevent shrinkage. Both phenomena, i.e. the strength build-up and the shrinkage, reduce the hydrostatic pressure in the cement column. In particular, the strength build-up increases the wall friction between cement and casing/formation. Cement is thereby enabled to "hang" on the walls, which reduces the pressure it exerts downhole. Shrinkage has a similar effect. In addition, suction develops in cement during setting as water is consumed in the hydration reaction (Appleby and Wilson, 1996). If the bottomhole pressure in the cement column drops below the formation fluid pressure, the influx of the latter into the annulus may commence. If the formation fluid in the interval happens to be gas, it will stream up the annulus creating a channel in the not-yet-hardened cement. After hardening is completed, the gas channel may persist providing a conduit and communication channel along the annulus.

3 WELL COMPLETION, STIMULATION AND PRODUCTION

3.1 Completion

Completion means making the well ready for production, and it involves the final well construction phases (preparation of the well in the pay zone region) and installation of necessary equipment for well production. A common pay zone completion design is the use of open-hole packers and ported sleeves along the lateral section of the well that can open or close, thereby isolating or allowing access to enable fracturing of specific intervals. An alternative design is complete casing and cementing of the lateral section of the well (as in Fig. 4) and the use of a perforation gun to create holes. These holes provide access to the pay zone. If this design is chosen, the casing has to be designed to handle the full producing zone pressure (or full fracturing pressure, whichever is higher) plus safety factors set by the type of well and life-of-well requirements. The last step of well construction is replacing the blowout preventer (BOP) with a wellhead. The latter is equipped with control valves and connections to production facilities.

The final completion step of a shale gas well includes hydraulic fracturing. Sometimes, however, several barriers of pipe/cement plus the wellhead controls and the tubing are added to the well after the hydraulic fracturing to form multiple well barriers (typically 2-5 are required). The strict regulations with respect to well barriers is the primary reason for the near absence of incidents in producing shale gas wells (King, 2012).

3.2 Stimulation

3.2.1 General overview

Unstimulated commercial production has been achievable in only a small proportion of shale formations with natural fracture networks (Curtis, 2002). In most cases, successful shale-gas recovery requires stimulation. The successful exploitation of shale-gas resources in North America was due to such technological developments within reservoir stimulation as high-volume fracturing also known as massive fracturing, zipper fracturing, optimization of the chemical composition of fracking fluids, and extensive use of multi-well pads (Gandossi, 2013).

Hydraulic fracturing (HF) using water-base or non-water-base fluids has become the most common technique for shale stimulation (Gandossi, 2013). It makes use of a liquid to fracture the reservoir rocks in order to increase the rock permeability and allow gas release and migration (Figure 5). A well stimulation job starts after a well has been drilled and completed. First, the casing is perforated along selected intervals within the production zone by using a perforation gun, and then a fracturing fluid is pumped into the wellbore at rates sufficient to increase the downhole pressure. When the pressure exceeds the strength of the rock, hydraulic fractures are formed.

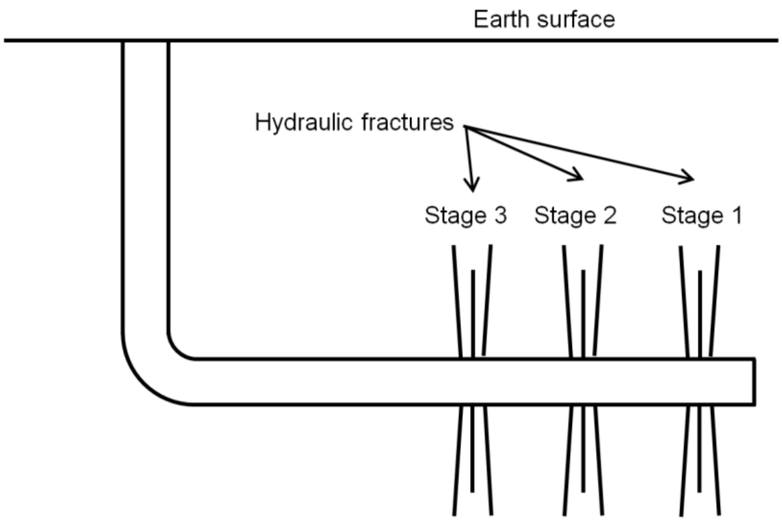

Figure 5 Multistage hydraulic fracturing from a horizontal well (not to scale).

The neat fracture pattern shown in Figure 5 is an idealization. In reality, fractures may take complex three-dimensional shapes determined by the orientation of the well, location and orientation of perforations, and directions of the principal in-situ stresses. In particular, the stress field near a wellbore is different from the far-field in-situ stress. Hydraulic fractures tend to propagate in such way that their surface is normal to the minimum in-situ stress. Therefore, if the direction of this stress in the near-well area is different from that in the far field, the fracture will experience a rotation (a twist) as it leaves the former. Such twisting is likely to create a bottleneck in the fracture shape near the well. Since all produced fluid must then go through this bottleneck, the fracture twisting may significantly impair the productivity of the stimulated well. In addition, a fracture twist may act as a flow constriction during subsequent proppant injection into the fracture, resulting in a so-called "proppant screen-out" (inability to deliver the proppant deep into the fracture) (Daneshy, 2003). Knowledge of in-situ stress state and optimization of well placement and orientation can significantly reduce the detrimental near-well effects in hydraulic fracturing. Three-dimensional HF modeling tools are required for HF optimization from horizontal and deviated wells.

A well may be too long to maintain sufficient pressure to fracture the formation along the entire well length. Thus plugs may be used to divide the well into shorter sections. These sections are fractured sequentially, starting from the section that is most remote from the well head. This sequential fracturing is called "*multi-stage fracturing/stimulation*". After fracturing has been finished, the plugs are drilled through, and the well is depressurized allowing the gas and other fluids to flow out of the shale formation into the well. Fracturing fluid mixed with the formation water returns to the surface. This water is called "flowback water" and is collected for later reuse or disposal. Usually less than 30% of the total water used in fracking flows back to the surface with the recovered gas. The remaining water stays underground and is mostly absorbed by the shale formation (Makhanov et al., 2014).
Fracturing can be performed simultaneously in two parallel horizontal wells from the same pad. During this simultaneous stimulation, the frac stages in the two wells are

alternated. Fractures created around each well thereby propagate toward each other. The superimposed induced stresses near the fracture tips create a more extensive fracture network (Rafiee et al., 2012). This technique, called "*zipper fracturing*", allows for enhancing fracture network complexity and maximizing the stimulated reservoir volume (Waters et al., 2009). After the fractures have been created, proppant may be injected into them. Proppant is a particulate material that is designed to keep fractures open during and after hydraulic fracturing.

Even when zipper fracturing is not employed, close location of wells drilled from one pad calls for a careful prediction of fracture growth and optimization of well placement. Namely, fractures generated from one well may inadvertently cross another well, and thereby create an unwanted hydraulic communications between the wells. Moreover, newly created hydraulic fractures may inadvertently intersect plugged and abandoned wells, and thereby jeopardize their integrity (Montague and Pinder, 2015).

3.2.2 Fracturing fluids

The most common fluid used in the hydraulic fracturing of unconventional gas reservoirs is "*slickwater*". In recent years, slickwater fracturing has become a standard stimulation technique in several U.S. shales, including Barnett, Marcellus, and Haynesville. Slickwater is a water-base fluid of low viscosity that contains a low fraction of friction reducing polymer, proppant and other chemicals:

- *Friction reducing agent***.** Generally, high molecular weight linear polymers fulfill friction reducing function. Typical friction reducing polymers are polyacrylamide and its derivatives and copolymers (Boothe et al., 1975, Hoover and Padden, 1969). These polymers are added to water at low concentrations in order to alter the rheological properties of the fluid to prevent turbulent flow at high pump rates (50-100 bpm) (Palisch et al., 2010). This, consequently, minimizes the amount of energy required to pump the fluid through the well (Blair et al., 2004). The friction reducing agents should be stable at high shearing forces, temperatures and pressures.

- *Proppants***.** Another slickwater component is proppant, a particulate (granular) material used to keep the incipient fracture open during and after a HF treatment. Without proppant, the fracture may easily close as the HF job is finished since, after flowback, there is not enough fluid pressure to keep the fracture opened. Fracture closing reduces the aperture and, thus, the fracture permeability (permeability of an open fracture is on the order of $w^2/12$ where w is the hydraulic aperture of the fracture). Proppant embedment is one of the challenges that need to be addressed in hydraulic fracturing. If the rock is sufficiently ductile or soft, indentation of proppant particles into the fracture face during closure may significantly reduce their permeability-enhancing effect. Conventional proppants include sand, ceramic, nutshells, and glass beads. An emerging technology relying on coating particles with polymers offers higher fracture conductivity, considerably reduced fines generation, and reduces scaling effects (Zoveidavianpoor and Gharibi, 2015).

- *Other chemicals.* Slickwater may also contain biocides, surfactants (wettability modification agents), scale inhibitors, and other substances.

The use of slickwater for hydraulic fracturing has both benefits and drawbacks (Palisch et al., 2010). A major benefit is the limited filter cake formation following slickwater use. Formation of a polymer filtercake at low permeability formation walls would negatively affect fracture conductivity. The low content of uncrosslinked/linear polymers used in slickwater is believed to impair the fracture conductivity to a lesser extent than the crosslinked polymers/gels usually do. In addition, slickwater contains a reduced number of different chemicals compared to other fracturing fluids, e.g. gels. This positively affects economic and environmental aspects of slickwater utilization. The fractures resulting from slickwater use are also very productive. The low proppant concentration and high injection rates in slickwater treatments support the development of complex fracture geometries and fracture systems (Fisher et al., 2002).

On the downside, the use of slickwater for fracturing requires large volumes of water. A fracture treatment requires from several to several thousand cubic meters of slick water per stage (GWPC and IOGCC, 2015). There is also a necessity to maintain high pump rates during the fracturing. Another drawback with the use of slickwater is the limited proppant transport capability (and thus also limited fracture-width). The low viscosity of slickwater limits its capability to suspend and effectively transport proppant particles. This in some cases necessitates application of more viscous fluids. Additional problem is high absorption of the fracturing fluid in complex fracture networks, and thus reduced water recovery and increased risk of formation damage with the use of slickwater.

Viscous fluids are a complementary solution to slickwater. They enable lower water usage compared to slickwater. Viscous fluids have viscosities several orders of magnitude higher than slickwater viscosity. The high viscosity of fluids allows higher amounts of proppant to be dispersed and transported compared to slickwater. Viscosified HF fluid viscosity is tuned by changing the polymer concentration. The typical composition of viscosified HF fluids used in fracturing of Fayetteville Shale is presented in Fig. 6. A major drawback with the use of viscous fluids is the higher number of chemicals used compared to slickwater and their tendencies to cause filter cake formation on the shale face.

The viscosified HF fluids, like slickwater, are water-based. Either fresh or reused HF water can be applied. Water usually constitutes more than 90 % of the fluid. The second component most abundant in viscosified HF fluid is proppant. In addition to proppant, a rich plethora of chemicals may be added to the water. These chemicals have different functions and generally represent less than 1% of the total composition of the fracking fluid (PennState, 2015, Arthur et al., 2009). According to their function, the chemicals used in HF fluids can be divided into the following groups:

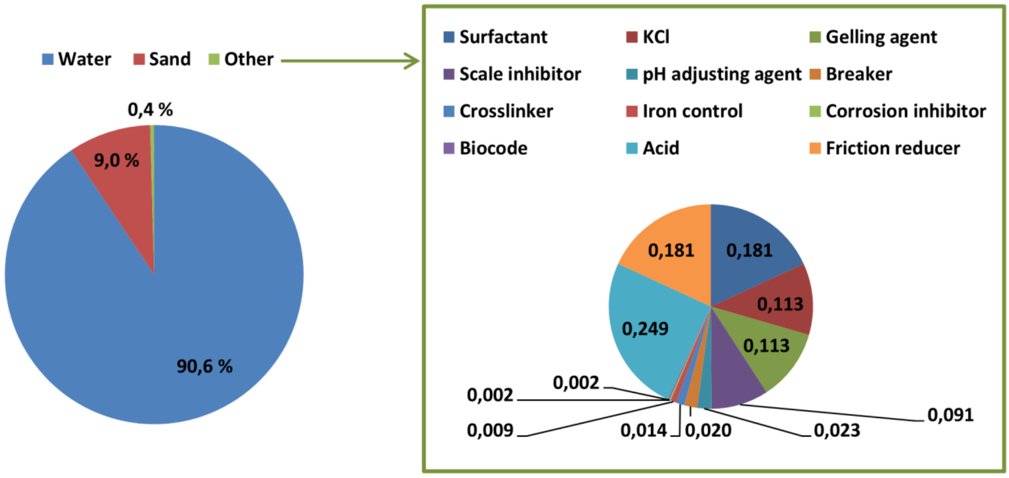

Figure 6 Exemplary viscous HF fluid composition typically used in HF of Fayetteville Shale. Adapted from (Arthur et al., 2009).

- *Viscosity modifiers.* Application of a viscosity modifier constitutes a major difference between slickwater and viscous HF fluids. Among viscosity modifiers used in HF, two groups of chemicals can be distinguished: (a) viscosity enhancers and (b) viscosity reducers. The viscosity of water is not sufficient to transport large amounts of proppant particles. In order to increase the proppant transport capability, the HF fluid has to be viscosified. To increase the viscosity of the HF fluid, polymers (either linear or crosslinked) can be used. Guar gum and its derivatives as well as cellulose derivatives like e.g. hydroxyethylcellulose are examples of viscosifying polymers. The choice of the viscosity enhancer is based on reservoir formation characteristics, such as thickness, porosity, permeability, temperature, and pressure. As temperatures increase, the viscosity of the solution tends to decrease (Arthur et al., 2009). In order to prevent the loss of viscosity, either polymer concentration can be increased, or cross-linking agents can be added. The cross-linking (gelation) of the linear polymers (e.g. guar gum) with e.g. metal ions like aluminum, chromium, titanium (EPA, 2004) can be performed. Cross-linking facilitates proppant transport. However, the usage of gels is not recommended for the stimulation of brittle shale formations (Lee et al., 2011). At the later stages of the HF process, the viscosity of the gelling agent has to be reduced in order to allow proppant release and to increase the volume of flowback water received after HF. The most common type of viscosity reducer, called also "breaker", is peroxydisulfate (e.g. ammonium persulfate) but enzymes can also be used (Gulbis et al., 1990). The breakers degrade viscosifying polymer chains. Such reduction in molecular weight of polymer leads to reduced HF fluid viscosity. High temperature usually facilitates the polymer degradation (Gulbis et al., 1990). In order to gain more control over when the polymer degradation starts or simply delay the degradation, the breaker can be temporarily protected by an encapsulating material (Gulbis et al., 1990, Burnham et al., 1980).

- *Acids* are utilized in the beginning of the HF treatment to remove cement deposited in the perforations and thus to provide access for HF fluid to the formation. The most common type of acid utilized in HF is hydrochloric acid. HCl can be used in concentrations ranging from 3% to 28% (Arthur et al., 2009).

- *Corrosion inhibitors* have to be applied along with acids in order to protect metal casing and tubing from acidic corrosion. Corrosion rates of carbon or chrome steels (although they can be corrosion resistant alloys) during acid stimulation are higher than under normal production conditions. Corrosion inhibitors for protection of such steels during acidizing are mostly different from those used to treat production fluids and usually added at higher concentrations (Kelland, 2009). Different corrosion protection mechanisms can be utilized during acid stimulation. One of them is inhibition of reduction and oxidation reactions that are the main cause of the corrosion at the metal surface. Another corrosion inhibition mechanism relies on strong adsorption of the corrosion inhibitor and formation of an organic, protective film on the metal surface. A recent paper has reviewed the mechanisms of corrosion inhibition and given examples of corrosion inhibitors (Dariva and Galio, 2014).

- *Biocides.* The water used for HF treatment obtained from local rivers, lakes, or gas field wastewater is typically contaminated by bacteria (Struchtemeyer and Elshahed, 2012). At the stage of HF fluid preparation this water is often mixed with biopolymer-based viscosity enhancers. The biopolymers can provide a good medium for bacterial growth and proliferation (Struchtemeyer and Elshahed, 2012). If sulfate-reducing or acid-producing bacteria become established in the wellbore, production of iron sulfide, hydrogen sulfide, bacteria induced corrosion and loss of fluid viscosity may negatively affect both production and well integrity. Biocides are chemicals used to minimize the risk of bacterial growth in HF fluids. One of the common chemical representatives of biocides is glutaraldehyde (Struchtemeyer et al., 2012). The efficacy of multiple biocides that are commonly used to control sulfate-reducing bacteria in fracturing fluids in shale gas formations was assessed by Struchtemeyer et al. (Struchtemeyer et al., 2012).

- *Oxygen scavengers.* Oxygen present in HF can cause corrosion to metal pipes and process equipment. The corrosion by-products (iron compounds) may in turn cause formation damage. Thus, oxygen removal from HF is necessary. The most common oxygen scavengers used in gas and oil production are sulphite (M_2SO_3), bisulphite ($MHSO_3$), and metabisulphite ($M_2S_2O_5$) salts (Kelland, 2009).

- *Iron precipitation control.* Precipitation of iron compounds like ferric hydroxide or ferric sulfide can cause damage to the permeability of the formation. Acids used in HF dissolve the iron sulfide, but in the process, hydrogen sulfide is generated which may stimulate corrosion. There are two classes of iron control chemicals designed to prevent ferric compounds from precipitation: (1) reducing agents that reduce iron(III) to iron(II) ions (ferric → ferrous) and (2) complexing agents (also called "sequestering agents" or "chelates") (Kelland, 2009).

- *Scale inhibitors.* There are several scales that typically form in wells: (1) calcium carbonate (2) sulfate salts of calcium, strontium, and barium, (3) sulfide salts of iron (II), zinc and lead (II) (Kelland, 2009). Scale inhibitors are water-soluble chemicals that prevent or retard the nucleation and/or growth of inorganic scales. Polymers like e.g. polycarboxylates or polyphospates are very common scale inhibitors for calcium salts scales (Kelland, 2009).

- *Clay stabilizers.* Shales are sedimentary rocks composed of consolidated minerals and clay particles (Arthur et al., 2009) with varied mineral-to-clay ratio. The clay content makes shales susceptible to swelling in aqueous solutions of low ionic strengths (low salinity). Such clay swelling may lead to so called "shale fracture surface softening" which is a dominant cause for conductivity reduction after water flow (Zhang, 2014). There are many strategies applied to prevent shale swelling (van Oort, 2003), but the most common is to add potassium chloride (KCl) in concentrations of 1-3 wt% (Arthur et al., 2009) or polyamines and polyquaternary ammonium salts e.g. polydimethyldiallylammonium chloride (Kelland, 2009).

Non-water based HF fluids can also be used for hydraulic fracturing. They are especially useful in water sensitive shale formations that can suffer from high water absorption. Such water absorption does not only negatively affect fracture conductivity and formation permeability, but it also results in large losses of HF fluids within the formation. These challenges can be overcome by applying non-water based fracturing solutions including liquefied gases.(Weijermars et al., 2011)

3.3 Production

After the hydraulic fracturing has been performed, an activity called fluid backflow, or just flowback, is performed. This is the action of cleaning up (or flowing) the well after hydraulic fracturing to recover parts of the fracturing fluid and to initiate gas production. The shale formation absorption, its water content, and the chemicals used in the frac fluid determines the recovery of fluids (King, 2012).

First gas flow from the shale gas well is typically seen from 2 days to 20 days after fracturing, depending on the back pressure, shale system permeability and flowback design (Edwards et al., 2011). As soon as gas has begun flowing, the rate of water recovery falls rapidly. How quickly it falls depends on regions, but in general the behavior is comparable. It is thus common to flow large early volumes of returning water to tanks for the first days, and then switch to through-the-separator flow with significantly lower water rates as the gas production begins.

Decline rates of production vary from region to region, but refracturing of wells is a way to prolong production. Many of the early Barnett shale reservoirs have been successfully refractured. In early vertical shale gas wells fractured with gels/foams, refracturing could double initial production and increase recoverable reserves. As multi-fractured horizontal wells became more popular, the effect of refracturing has diminished in many wells (King, 2012).

4 WELL ABANDONMENT

When a shale gas well has reached the end of its productive life, it will need to be plugged and abandoned (P&A'ed). This is typically done by a similar procedure to that performed on conventional oil and gas wells. Even if P&A regulations vary from location to location, the intent is always to keep fluid isolated in the zones in which they naturally reside. Both hydrocarbon reserves and groundwater are viewed as requiring special protection.

The well plugging procedure typically involves setting cement plugs in discrete sections of the well, with heavy mud filling the space between them. For the well in Fig. 4, a schematic abandonment design is illustrated in Fig. 7. Placing mud between the plugs is useful, as it gives better sealing than a fully cemented column, because the mud can deform and seal off leakages. This generates an overbalanced environment in the well. As seen by comparing Figs. 4 and 7, the P&A design reinforces barriers in the completion design. In some cases it might also be necessary to remove sections of the steel pipe and cement, and use special cement plugs to isolate intervals of the wellbore. The sealing ability of plugs is verified through pressure testing and "tagging" (mechanical indentation on the material) using the drill bit.

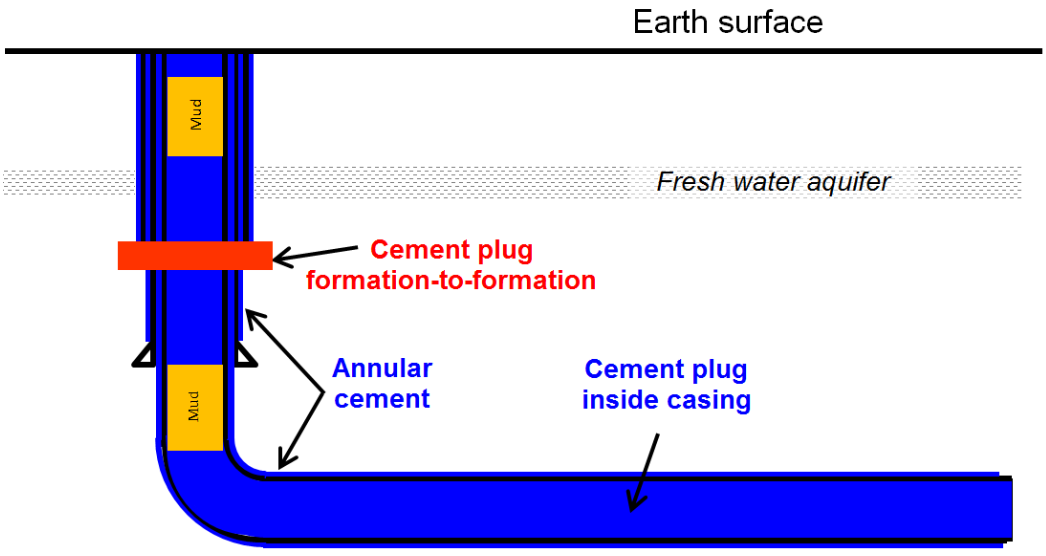

Figure 7 Schematic well plugging and abandonment design for the generic well depicted in Fig. 4 (not to scale).

5 DISCUSSION

This report has summarized the typical execution of shale gas drilling, completion, production and abandonment operations today. More detailed information on exact requirements for wells that are to be hydraulically fractured can be found in two documents published by the American Petroleum Institute (API):[2]

- **API Guidance document HF1:** Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines. 1st edition, Oct. 2009.
- **API Standard 65-Part 2:** Isolating Potential Flow Zones During Well Construction. 2nd edition, Dec. 2010.

These are technical guidelines for well construction of HF-stimulated wells, and they have been made openly available to the public. The documents form the basis of this report together with scientific studies on shale gas well operations. As a wrap-up, this chapter will outline the environmental impact of all procedures described in chapters 2-4, and it will outline future work in the project.

5.1 Environmental impact of well operations

5.1.1 Drilling and well construction

Environmental impact of drilling can be due to the following factors (Olawoyin et al., 2012): (1) water demand for drilling fluid; (2) drilling-fluid spill incidents; (3) noise from the drilling rig; (4) increased truck traffic; (5) topographic and visual footprint of the drilling site; (6) emissions during drilling; (7) disposal of cuttings and drilling fluid. The environmental impact of drilling is dependent on the number of wells being drilled per area and it can be reduced by drilling several wells from one site; use of directional and horizontal drilling; use of multilateral wells; use of air drilling or water-base muds. Good drilling practices, e.g. avoiding excessive damage to the borehole wall, also help in creating high-quality robust wells.

Cementing is a crucial element in obtaining zonal isolation along the vertical section of the well, and if this fails, the environmental impact can be large. During the production phase of a shale gas well, the pressure and temperature inside the well will vary repeatedly and significantly. This temperature/pressure cycling can have a detrimental effect on the bonding of cement to steel casing and rock, and create radial cracks, disking or so-called microannuli. All these defect types are difficult to observe by standard well logging tools. If left untreated, they can cause chronic leakages from wells even after abandonment. To minimize this risk, shale gas wells should be constructed in order to seal during and after hydraulic fracturing and production operations. This requires *careful choice of well barrier materials during well construction***,** such as

[2] Free download from API web page: http://www.api.org/Policy-and-Issues/Policy-Items/HF/API_HF1_Hydraulic_Fracturing_Operations and http://www.api.org/Policy-and-Issues/Policy-Items/Exploration/65-2_Isolating_Potential_Flow_Zones

sealant (typically cement) and casing. Care must be taken to map how materials are degraded by chemicals used for fracturing and how they are mechanically eroded by proppant flow. Since high pressures are a crucial element in economical production from shale, the well also needs to withstand these without suffering from fracturing.

5.1.2 Hydraulic fracturing and production

Contamination is the main environmental concern associated with hydraulic fracturing. This can occur as a result of inappropriate well design/construction, or be caused by well failure. The latter is difficult to predict, as long-term impact of HF chemicals and proppant flow on well construction elements/barriers and infrastructure has not yet been sufficiently studied. Relevant contaminants are: HF, fracturing chemicals, methane naturally occurring in the subsurface, radioactive substances (from chemicals or soil), hydrocarbons and heavy metals. Another environmental concern with its roots in the subsurface is fracturing-induced earthquakes (anthropogenic/induced seismicity).

Topside environmental concerns are related to waste disposal from HF operations: (1) contamination of soil and surface water due to spill of chemicals from storage tanks or due to inadequate treatment or transport of flowback water; (2) air pollution impacts, e.g. methane emission and its impact on climate change; (3) Large water consumption in water-deficient regions. In general, the environmental risk can be minimized by applying more environmentally friendly chemicals, waste disposal methods and by developing improved well and topside monitoring systems.

5.1.3 Well abandonment

Shale gas wells are drilled onshore, sometimes in densely populated regions or in proximity to groundwater sources. As a result, long-term well integrity is important to maintain in shale gas wells. This can be a challenge, as shale is a formation type that naturally creeps (flows/deforms with time). In Norway this behavior is the motivation for investigating whether shale formations could function as permanent barriers in wells (Williams et al., 2009). The shale creep can, however, also cause plug or casing deformation over time – which needs to be understood to maintain well integrity.

5.2 Future work

This report is the first in a series of reports that will be published from the Work Package (WP) on "Drilling hazards and well integrity" in the M4ShaleGas project. Future work will focus on:

- Documenting emerging well technologies, methods and materials for shale gas operations, with focus on why there was a need for these in the first place.

- Developing research-based advice on how to minimize risks and impacts of shale gas well operations in Europe, and how to generally improve shale gas well integrity.

6 CONCLUSIONS

The report provides a summary of today's best practices for shale gas drilling, completion, production and abandonment operations. Most are similar to those of ordinary oil/gas wells, but some shale specific aspects are outlined. In general, shale specific well operations are related to the following issues:

- **High safety requirements** due to onshore drilling in/near populated regions where public acceptance might be an issue due to e.g. a fear of groundwater pollution.
- Drilling long sections in hard non-porous rock where no filter cake builds up and **borehole stability** might be an issue.
- Drilling and completing **long horizontal well sections** in non-porous rock.
- **Hydraulic fracturing stimulation** of the reservoir requiring robust well construction that can handle a variety of chemicals, proppant back-production, high pressures, high pressure variations.
- Ensuring efficient and **safe well abandonment in shale formations that naturally creep** and close up the borehole over time.

7 REFERENCES

AGBAJI, A., LEE, B., KUMAR, H., BELVALKAR, R., ESLAMBOLCHI, S., GUIADEM, S. & PARK, S. 2009. Report on Sustainable development and design of Marcellus shale play in Susquehanna, PA. *The Institute for Energy & Environmental Research for Northeastern Pennsylvania, Technical Report.*

APPLEBY, S. & WILSON, A. 1996. Permeability and suction in setting cement. *Chemical Engineering Science,* 51**,** 251-267.

ARTHUR, J. D., BOHM, B. K., COUGHLIN, B. J., LAYNE, M. A. & CORNUE, D. 2009. Evaluating the Environmental Implications of Hydraulic Fracturing in Shale Gas Reservoirs. SPE paper 121038 presented at the SPE Americas E&P Environmental and Safety Conference, 23-25 March, San Antonio, Texas. Society of Petroleum Engineers.

BLAIR, C. C., CHANG, K. T., TREYBIG, D. S. & GERKEN, K. S. 2004. Use of dispersion polymers as friction reducers in aqueous fracturing fluids. US patent number 6787506 B2.

BOOTHE, J. E., MARTIN, F. D. & SHARPE, J. A. J. 1975. Friction reducing compounds for use in hydraulic fracturing fluids. US patent number 3868328 A.

BURNHAM, J. W., BRISCOE, J. E. & ELPHINGSTONE, E. A. 1980. Methods and additives for delaying the release of chemicals in aqueous fluids. US patent number 4202795 A.

CURTIS, J. B. 2002. Fractured shale-gas systems. *AAPG Bulletin,* 86**,** 1921-1938.

DANESHY, A. A. 2003. Off-balance growth: A new concept in hydraulic fracturing. *Journal of Petroleum Technology***,** 78-85.

DARIVA, C. G. & GALIO, A. F. 2014. *Developments in Corrosion Protection: Chapter 16. Corrosion Inhibitors - Principles, Mechanisms and Applications,*, InTech.

DARRAH, T. H., VENGOSH, A., JACKSON, R. B., WARNER, N. & POREDA, R. J. 2014. Noble gases identify the mechanisms of fugitive gas contamination in drinking-water wells overlying the Marcellus and Barnett Shales. *PNAS,* 111**,** 14076-14081.

DAVIES, R. J., ALMOND, S., WARD, R. S., JACKSON, R. B., ADAMS, C., WORRALL, F., HERRINGSHAW, L. G., GLUYAS, J. G. & WHITEHEAD, M. A. 2014. Oil and gas wells and their integrity: Implications for shale and unconventional resource exploitation. *Marine and Petroleum Geology,* 56**,** 239-254.

EDWARDS, K. L., WEISSERT, S., JACKSON, J. B. & MARCOTTE, D. 2011. Marcellus Shale Hydraulic Fracturing And Optimal Well Spacing To Maximize Recovery And Control Costs. SPE paper 140463 presented at the SPE Hydraulic Fracturing Technology Conference, 24-26 January, The Woodlands, Texas, USA Society of Petroleum Engineers.

EPA 2004. Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs. *EPA 816-R-04-003 Hydraulic Fracturing Fluids*.

FISHER, M. K., WRIGHT, C. A., DAVIDSON, B. M., GOODWIN, A. K., FIELDER, E. O., BUCKLER, W. S. & STEINSBERGER, N. P. 2002. Integrating Fracture Mapping Technologies to Optimize Stimulations in the Barnett Shale. SPE paper 77441 presented at the SPE Annual Technical Conference and Exhibition, 29 September-2 October, San Antonio, Texas. Society of Petroleum Engineers.

GANDOSSI, L. 2013. An overview of hydraulic fracturing and other formation stimulation technologies for shale gas production. *JRC Technical Reports*.

GOLD, R. 2012. Faulty Wells, Not Fracking, Blamed for Water Pollution. *The Wall Street Journal*, March 25.

GRADISHAR, J., UGUETO, G. & VAN OORT, E. 2014. Setting free the bear: the challenges and lessons of the Ursa A-10 deepwater extended-reach well. *SPE Drilling & Completion***,** 182-193.

GULBIS, J., WILLIAMSON, T. D. A., KING, M. T. & CONSTIEN, V. G. 1990. Method of controlling release of encapsulated breakers. European patent number EP 0404211 A1.

GUO, Q., JI, L., RAJABOV, V., FRIEDHEIM, J., PORTELLA, C. & WU, R. 2012. Shale gas drilling experience and lessons learned from Eagle Ford. SPE paper 155542 presented at the Americas Unconventional Resources Conference held in Pittsburgh, Pennsylvania, USA, 5-7 June 2012.

GWPC & IOGCC. 2015. *FracFocus Chemical Disclosure Registry* [Online]. Ground Water Protection Council (GWPC) and Interstate Oil and Gas Compact Commission (IOGCC). Available: https://fracfocus.org [Accessed 2015].

HOOVER, M. F. & PADDEN, J. J. 1969. Thickened friction reducer for waterbased oil well treating fluids. US patent number 3442803 A.

KELLAND, M. A. 2009. *Production Chemicals for the Oil and Gas Industry*, CRC Press.

KING, G. E. 2012. Hydraulic Fracturing 101: What Every Representative, Environmentalist, Regulator, Reporter, Investor, University Researcher, Neighbor, and Engineer Should Know About Hydraulic Fracturing Risk (SPE-0412-0034-JPT). *Society of Petroleum Engineers*.

LEE, D. S., HERMAN, J. D., ELSWORTH, D., KIM, H. T. & LEE, H. S. 2011. A critical evaluation of unconventional gas recovery from the marcellus shale, northeastern United States. *KSCE Journal of Civil Engineering*, 15**,** 679-687.

MAKHANOV, K., HABIBI, A., DEHGHANPOUR, H. & KURU, E. 2014. Liquid uptake of gas shales: A workflow to estimate water loss during shut-in periods after fracturing operations. *Journal of Unconventional Oil and Gas Resources*, 7**,** 22-32.

MONTAGUE, J. A. & PINDER, G. F. 2015. Potential of hydraulically induced fractures to communicate with existing wellbores. *AGU Water Resources Research,* 51.

NELSON, E. B. & GUILLOT, D. (eds.) 2006. *Well cementing*: Schlumberger.

OLAWOYIN, R., WANG, J. Y. & OYEWOLE, S. A. 2012. Environmental safety assessment of drilling operations in the Marcellus-Shale gas development. *SPE Drilling & Completion,* 18**,** 1-9.

PALISCH, T. T., VINCENT, M. & HANDREN, P. J. 2010. Slickwater Fracturing: Food for Thought. SPE paper number 115766. *SPE Production & Operations,* 25.

PENNSTATE. 2015. *Public Media for Public Understanding: Explore Shale* [Online]. Pennsylvania State University Public Broadcasting. Available: http://exploreshale.org/ [Accessed 2015].

RAFIEE, M., SOLIMAN, M. Y. & PIRAYESH, E. 2012. Hydraulic Fracturing Design and Optimization: A Modification to Zipper Frac. SPE paper number 159786 presented at the SPE Annual Technical Conference and Exhibition, 8-10 October, San Antonio, Texas, USA Society of Petroleum Engineers.

REHM, B., SCHUBERT, J., HAGHSHENAS, A., PAKNEJAD, A. S. & HUGHES, J. (eds.) 2008. *Managed pressure drilling,* Houston: Gulf Publishing Company.

RIDLEY, K., JURGENS, M., BILLA, R. J. & MOTA, J. F. 2013a. Eagle Ford shale well control: drilling and tripping in unconventional oil and gas plays. SPE paper 163984 presented at the SE Middle East Unconventional Gas Conference and Exhibition held in Muscat, Oman, 28-30 January 2013.

RIDLEY, K., JURGENS, M., BILLA, R. J. & MOTA, J. F. 2013b. Eagle Ford shale well control: drilling and tripping in unconventional oil and gas plays. SPE paper 163984 presented at the SPE Middle East Unconventional Gas Conference and Exhibition held in Muscat, Oman, 28-30 January 2013.

ROYALSOCIETY 2012. Shale gas extraction in the UK: a review of hydraulic fracturing. *Report by The Royal Society and The Royal Academy of Engineering.* London.

STRUCHTEMEYER, C. G. & ELSHAHED, M. S. 2012. Bacterial communities associated with hydraulic fracturing fluids in thermogenic natural gas wells in North Central Texas, USA. *FEMS Microbiology Ecology,* 81**,** 13-25.

STRUCHTEMEYER, C. G., MORRISON, M. D. & ELSHAHED, M. S. 2012. A critical assessment of the efficacy of biocides used during the hydraulic fracturing process in shale natural gas wells. *International Biodeterioration & Biodegradation,* 71**,** 15-21.

VAN OORT, E. 2003. On the physical and chemical stability of shales. *Journal of Petroleum Science and Engineering,* 38**,** 213-235.

WATERS, G. A., DEAN, B. K., DOWNIE, R. C., KERRIHARD, K. J., AUSTBO, L. & MCPHERSON, B. 2009. Simultaneous Hydraulic Fracturing of Adjacent Horizontal Wells in the Woodford Shale. SPE paper number 119635 presented at the SPE

Hydraulic Fracturing Technology Conference, 19-21 January, The Woodlands, Texas Society of Petroleum Engineers.

WATTERS, J. 2012. RPSEA Task 2.0 Technology Status Assessment. 10122-19.02. Lowering Drilling Cost, Improving Operational Safety, and Reducing Environmental Impact through Zonal Isolation Improvements for Horizontal Wells Drilled in the Marcellus Shale 10122-19. Houston.

WEIJERMARS, R., DRIJKONINGEN, G., HEIMOVAARA, T. J., RUDOLPH, E. S. J., WELTJE, G. J. & WOLF, K. H. A. A. 2011. Unconventional gas research initiative for clean energy transition in Europe. *Journal of Natural Gas Science and Engineering,* 3**,** 402-412.

WILLIAMS, S. M., CARLSEN, T., CONSTABLE, K. C. & GULDAHL, A. C. 2009. Identification and Qualification of Shale Annular Barriers Using Wireline Logs During Plug and Abandonment Operations. SPE paper number 119321 presented at the SPE/IADC Drilling Conference and Exhibition, 17-19 March, Amsterdam, The Netherlands. Society of Petroleum Engineers.

WYLIE, G. 2012. Shale gas. *World Petroleum Council Guide: Unconventional Gas* [Online].

ZHANG, J. 2014. Fracture Conductivity Damage by Water in Shale Formations. SPE paper number 173473 presented at the SPE Annual Technical Conference and Exhibition, 27-29 October, Amsterdam, The Netherlands Society of Petroleum Engineers.

ZOVEIDAVIANPOOR, M. & GHARIBI, A. 2015. Application of polymers for coating of proppant in hydraulic fracturing of subterraneous formations: A comprehensive review. *Journal of Natural Gas Science and Engineering,* 24**,** 197-209.

