OR/15/066 Engineering considerations

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This chapter discusses the knowledge of drilling engineering and review the understanding of how drilling operations can influence the pattern and extent of hydraulic fractures. This chapter will draw on the operational considerations introduced in Hydraulic fracturing and the theory introduced in all chapters.

Hydrofractured zone extension

The hydrofracture zone is simply the gross volume of rock at depth that contains fractures generated by the hydraulic fracture stimulation. A shale gas operator will begin by designing a hydrofracture zone based on a given numerical model, or based upon local experience. The zone will be dependent on parameters including hydraulic fracture volume and pressurization rate. The early stage of hydraulic fracture stimulation (i.e. during the first few stages of hydraulic stimulation) will be aimed at validating and/or calibrating the hydrofracture zone model. This can be done using micro-seismic analysis or tilt meters for direct traces; or indirectly using pressure build up, production tests or interference tests (Fisher et al., 2004[1]; Fix et al., 1991[2]; King, 2012[3]; King & Leonard, 2011[4]; Woodroof et al., 2003[5]). Considerable understanding can also be obtained from analysis of core recovered from drilling.

Considerable understanding of the hydrofracture zone has come from microseismic monitoring. Excellent signal strength and high amplitude microseismicity has led to increased precision with respect to the event locations (Detring & Williams-Stroud, 2012[6]). Microseismic mapping demonstrates that an interconnected fracture network of moderate conductivity with a relatively small spacing between fractures is achievable by hydraulic fracturing (Warpinski et al., 2009[7]). The subsequent production from these reservoirs supports both the modelling and the mapping. Maxwell et al. (2011)[8] present results from microseismic measurements integrated with seismic reservoir characterization and injection data to investigate variability in the hydraulic fracture response between three horizontal wells in the Montney shale in NE British Columbia, Canada. Microseismic events occurred from 200 to 1,200 m away from the point of injection (source site). It was observed that hydraulic fractures tended to be asymmetric and grew preferentially towards the low Poisson's ratio region of the shale unit. This is attributed to material property changes and associated lower stresses in these regions.

Since the start of injection of brine into a single deep injection well in 1991 in Paradox Valley, Colorado, earthquakes have been repeatedly induced (Yeck et al., 2015[9]). The induced seismicity separates into two distinct source zones: a principle zone (>95% of the events) asymmetrically surrounding the injection well to a maximum radial distance of ~3 km, and a secondary, ellipsoidal zone, ~2.5 km long and centered ~8 km northwest of the injection well. Within the principal zone, hypocenters align in distinct linear patterns, showing at-depth stratigraphy and the local Wray Mesa fracture and fault system. The primary faults of the Wray Mesa system are aseismic, striking subparallel to the inferred maximum principal stress direction, with one or more faults, probably acting as fluid conduits to the secondary seismic zone. Individual seismic events in both zones do not discernibly correlate with short-term injection parameters; however, a 0.5 km^2 region immediately northwest of the injection well responds to long-term, large-scale changes in injection rate and the surpassing of a threshold injection pressure. In addition, the fault planes are consistent with principal stress directions determined from borehole breakouts (Yeck et al. 2015[9]). This illustrates the complex response of a naturally fractured geological unit to changes in reservoir pressure.

Hydraulic fracture fluid

Hydraulic fracture fluid plays a vital role in the formation of hydraulic fractures. Fisher et al. (2004)[1] examined microseismic monitoring results and found that hydraulic fractures propagate in both horizontal and vertical directions in complex patterns rather than single symmetric patterns. They also noted that a larger volume of fracturing fluid leads to a wider area swept by microseismic events and a higher gas yield. This suggests that a limit can be imposed on fracture propagation based on the volume of fluid injected. It may be theoretically possible to create a pressure that could overcome geological stresses so that a fracture could grow vertically to shallow depths or even the surface. However, this is not feasibly practical. During fluid injection a certain amount of leak-off is experienced, this is caused by fluid flowing into the shale gas unit or entering natural fractures and is pressure dependent. Different shale types will result in variations in leak-off. In order to create such an enormous hydraulic pressure that a fracture would propagate significant distances there would become a point where injection rate would equal leak-off and therefore the fracture could simply not grow any further (King, 2010[10]; Fisher & Warpinski, 2012[11]; Mair et al., 2012[12]).

Flewelling et al. (2013)[13] performed a fracture height study based on a simple energy balance. In order to hydraulically fracture shale, energy is needed to (1) counteract the least principal stress; (2) displace and open the walls of the fracture; (3) propagate the fracture at the fracture tip; and (4) counteract energy dissipation due to fluid viscosity and leak-off of fluid pressure. Flewelling et al. compared end-member situations for given pore fluid pressure, Young's modulus, and fracture aspect ratio with data from 1,754 individual shale gas and tight rock conventional wells. This showed that the maximum fracture height is linked to the volume of the hydraulic fluid injected. All microseismic data showed the maximum observed fracture length was 600 metres, with the majority of heights much less than this.

King (2012)[3] discussed leak-off and its role on arresting fracture growth. The rate of leak-off was seen to correlate with the maximum fracturing network possible in the formation. The formation contact area that the fracturing fluid creates is normally very large and is about 10,000 to 100 000 m^2 in a densely, naturally fractured shale well. This volume usually has a total extent of 30 metres away from the wellbore.

The observations above suggest that the extent of fracturing is strongly correlated with the volume of hydraulic fracturing fluid injected. Therefore, this suggests that maximum fracture heights can be controlled by the volume of fluid used.

Pressurization rate

As stated above (Hydraulic fracture fluid) the rate of fluid pressurization has a theoretical maximum related to the leak-off rate of the geological formation. This suggests that fluid pressurization rate has a role in hydraulic fracture formation.

Zhao et al. (2012)[14] present a theoretical study of pressurization rate on the interaction between induced and natural fractures. They discuss the linkage of natural fractures at their tips during hydraulic stimulation to create a fracture mesh. This research suggests that a critical pump pressurization rate is required to form an intensive fracture mesh. This critical pump rate varies as the angle between the natural fractures and the stimulated fractures varies; with a minimum achieved if natural fractures are perpendicular to the well. The critical pump rate is also dependent on the natural fracture length and the elastic properties of the shale. Whilst this research is purely theoretical, it suggests that the formation of a well-developed inter-connected fracture network during hydraulic stimulation is dependent on the pressurization rate of the fracture fluid.

Bing et al. (2014)[15] present results from a laboratory study simulating hydraulic fracturing down a scaled borehole in a cubic sample of shale. The experimental study simulated field injection rates of between 9 and 16 m^3/min. It was observed that difficulty occurred in generating hydraulic fractures at low injection rates. At the highest injection rates the formed fractures were more complex, but did not necessarily result in a greater volume of the rock being fractured. The highest pressurization rate leads to pressure build-up, which results in greater energy loss and insufficient time for filtration to reduce the strength of the shale. Variable injection rates were seen to increase the likelihood of interaction between induced fractures and the naturally occurring fracture network. Generally a high injection rate is required to maintain open propagation of fractures and to ensure they remain open. This experimental study showed that an injection rate of 10 m^3/min and a viscosity of 10 mPa.s are optimal if using constant rate pressurization. It should be noted that there is a maximum rate that the fluid can be pumped; this is dependent on the power of pump trucks and the diameter and length of the well.

Hydraulic fracture design

Considerable effort has been afforded in recent years to improving the efficiency of hydraulic fracturing and to improve gas extraction from shale. This section discusses advanced hydraulic fracturing techniques.

The Texas two-step method (East et al., 2010[16]) is a hydraulic fracturing method that has been developed to take advantage of changes in minimum horizontal stress in response to fracture spacing as a result of stimulation in horizontal wells. The method is an alternating stimulation method, after creating the first and second interval a third is conducted between the first two. Each hydraulic stimulation alters the local stress field. Any change in stimulation sequence alters the stress in the area between fractures and activates the stress-relieved discontinuities. This can create a complex network of fractures connected to the main hydraulic fractures (Rafiee et al., 2012[17]). The Texas two-step uses the stress shadow from the previous fracturing treatment to increase the likelihood of transverse fractures forming. This method results in a complex network of conductive fractures close to the well with a high fracture surface area. Controlling hydraulic fluid volumes means that only the local rock-mass to the well is stimulated. This generates good gas yield with a reduced risk of hydraulic fractures propagating vertically through the shale sequence.

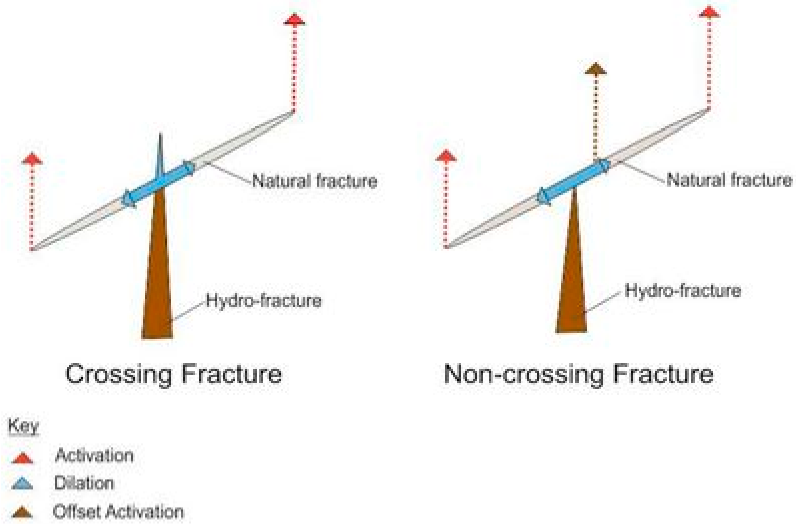

Figure 10 Shale completion schemes using dual boreholes: a) simultaneous hydraulic fracturing; b) sequential hydraulic fracturing (zipper-frac); c) Modified zipper-frac. Re-drawn from Nagel et al., 2013.

Waters et al. (2009) [18] introduce the concept of simultaneous fracturing, in which two parallel horizontal wells are stimulated simultaneously. The stress perturbation created by simultaneously hydraulically fracturing in two boreholes results in the promotion of fractures propagating between the wells. When hydraulic fracturing intervals are directly opposite one another in the well, the technique is referred to as aligned fracturing, simultaneous fracturing or simul-frac (Figure 10a). A modification to this technique is the zipper-frac where the sequence of simultaneous hydraulic fracturing is shown in Figure 10b. This has been further developed into the modified zipper-frac, where a staggered pattern of stimulation occurs, as shown in Figure 10c. All of these techniques exploit the stress distribution around fractures and create a more complex fracture pattern (Rafiee et al., 2012[17]). In simul-frac, when the opposite fractures propagate toward each other, a degree of interference occurs between the tips of the fractures and forces the fractures to propagate perpendicular to the direction of the horizontal wellbore. Whilst the modified zipper-frac technique relies on stress interference caused by the middle fracture initiated from the other lateral. Rafiee et al. (2012)[17] proposed and modelled the modified zipper-frac technique. They showed that the technique creates a more complex fracture network without the operational issues observed in the other simultaneous hydraulic fracturing techniques. The complexity of the formed fractures is dependent on the spacing between the two parallel boreholes, with spacing expected to be between 150 and 300 metres. This modelling exercise showed that the stress interference between fractures can create an effective stimulated reservoir volume to enhance hydrocarbon production.

The examples introduced show that the use of dual boreholes has the potential to increase hydrocarbon return. A by-product of this is a complex fracture development in a restricted volume that occurs predominantly between the stimulated wells; thus containing the extent of the stimulated reservoir volume. However, the use of two wells increases costs and is generally used where an economic return is expected.

The role of proppants and additives

As introduced in Fracturing fluids, fracturing fluid normally consists of water with a range of additives to assist in the fracturing process and to increase the life of downhole infrastructure. Cuadrilla Resources Limited state that in the UK less than 0.05% of the fracturing fluid is made up of chemical additives (Stamford & Azapagic, 2014[19]). King (2012)[3] states that friction reducer and biocide constitute the most common additives representing about 0.025% and 0.005–0.05% of the total volume respectively. As shown in Table 1, between 3 and 13 types of chemical additives are used in different mixtures depending on specific well conditions. Also added to the fracturing fluid is proppants, with the primary function of propping open hydraulic fractures once they have formed. These are made up of crush-resistant solid materials; commonly sand, but also ceramic beads, aluminium beads and sintered bauxite. Proppants remain suspended in the fracturing water with the aid of thickening agents. Generally, proppants constitute 1–10% of the total fracture fluid volume. The thickeners, also called gelling agents or solidifiers, are chemicals used to increase the water's viscosity. The most common thickener is guar gum.

While there have been several studies looking at proppants and additives, there has been limited research into the role of additives and proppants on hydraulic fracture formation and the extent of the stimulated reservoir volume. Fluid viscosity is one factor that is used in predicting hydraulic fractures. As introduced above, Flewelling et al. (2013)[13] state that energy is needed to counteract energy dissipation due to fluid viscosity and leak-off of fluid pressure during hydraulic fracturing of shale. The permeability of the host shale unit is also going to be viscosity dependent, which will dictate fluid leak-off. Therefore additives will play a role in the extent of hydraulic fracturing. The lack of open literature on the role of additives on fracture propagation is seen as a gap in current knowledge.

Geological considerations

Shale variability highlighted that the term 'shale' covers a range of sedimentary rocks that have a large contrast in physical properties. Havens (2012)[20] for instance, shows that the Bakken Formation has a wide range of elastic properties and has strong anisotropy. Hawkes (2015)[21] showed variation in tensile strength with facies of the Bakken Formation, with averages for each of the 9 identified facies ranging in tensile strength from 6 to 16 MPa. The uniaxial strength of Bowland Shale in the UK has been shown to range from 62–91 MPa (de Pater & Baisch, 2011[22]). Hence, considerable variability is seen within a geological sequence of shale.

Theory states that hydraulic fractures will grow in the direction of maximum stress. Field experience has shown that fractures tend to propagate upward until contact is made with a rock of different structure, texture, or strength which stops the fracture growth (King, 2012[3]). Fisher & Warpinski (2011)[23] observe height-growth limiting mechanisms controlled by geological structure, with a mix of horizontal and vertical fractures created below a critical depth. King et al. (2008)[24] report height limiting of 15 to 30 metres in the Barnett well, even though no obvious immediate rock strata barriers were identified. However, it could be argued that some form of discontinuity was present. The observation that horizontal fractures can predominate during hydraulic fracturing shows that geology plays a large role in dictating the propagation of fractures. This means that experience can be used to ensure the correct units are hydraulically stimulated if there are any risks associated with upward migration of hydraulic fractures. Selecting facies that are weak within a shale formation will result in lithologically bound fractures that are not able to migrate into stronger bounding units.

Knowledge gaps and recommendations

This chapter has described the state of understanding of the control that drilling engineers have on the extent of the propagation of hydraulic fractures during stimulation. The following statements on current knowledge, knowledge gaps and recommendations can be made:

- The use of microseismic monitoring has increased the knowledge of the extent of the stimulated reservoir volume. This has allowed model predictions to be calibrated and refined.

However, numerical models have been limited in their ability to fully describe hydraulic fracturing in certain settings suggesting the full physics of the system is not encapsulated within the modelling approaches.

- The full complexity of the formed fracture network is not fully understood. A means of determining fracture density and other fracture properties is needed.
- Hydraulic fracture fluid volume plays a role on the full extent of hydraulic fractures. While the processes governing the role of fluid volume are
- understood, a means of predicting fracture propagation lengths is not yet available.
- The process of leak-off needs to be better understood in order to better predict fracture lengths. This includes the role of pre-existing fractures on leak-off and the role of the permeability of the shale.
- The role of hydraulic fracture fluid pressurization rate is acknowledged. However, a full understanding of this has yet to be achieved.
- Advanced hydraulic fracturing design has been proposed. The full consequence of these strategies has yet to be realized. Complex, controlled fracture networks are theoretically possible; these need to be properly tested in the field to refine drilling engineering.
- Proppants and additives act to alter the viscosity of the hydraulic fluid. The full impact of this on fracture propagation and networks has yet to be achieved.
- Considerable variation in physical properties of shale facies results in lithologically bound fracture networks. This needs to be tested on European shale units.

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