OR/15/066 Fracture propagation

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The section titled Fracture initiation introduced the mechanisms that dictate when hydraulic fractures are formed. This chapter discusses the mechanisms responsible for the propagation of the formed hydrofractures; what dictates how long a fracture is, which direction do fractures propagate, and how dense is the fracture network. Two methods can be employed to determine the propagation of hydraulic fractures; 1) the monitoring of hydraulic fracturing during shale gas exploration using microseismic methods, and 2) the study of natural hydraulic fractures.

Discontinuities can be thought of in terms of single microcracks, which are planar discontinuities, or a linkage of many jogs and sharp bends, which on an atomic scale are sharp severances of atomic bonds within the crystal lattice as shown by electron microscopy (Lawn, 1983). Larger scale discontinuities are created by the coalition of many microcracks. A macroscopic brittle crack is a discontinuity formed by a complicated rupture event that has cut a large number of grains, without significant prior deformation at a particular stress (Paterson, 1978). Thus, a discontinuity's initiation and growth depends on the initiation and coalition of microcracks.

Theoretical considerations

Generally hydraulic fracturing involves the following physical processes: mechanical deformation, induced by pressure change in fractures and pores; fluid flow within fracture and formation, including their interactions; fracture propagation; as well as proppant transport and settling inside the fracture (Zhou *et al.*, 2014[1]). Any theoretical model needs to account for all of these aspects within a heterogeneous shale experiencing a heterogeneous stress-field.

Considerable effort has been afforded to hydraulic fracture growth in rocks in recent years, especially in shale gas formations. This has been aided by micro-seismic monitoring, which can observe the complexity of the fracture network that develops (e.g. Calvez *et al.*, 2007[2]; Cipolla *et al.*, 2005[3]; Daniels *et al.*, 2007[4]; Fisher *et al.*, 2002[5]; Maxwell et at., 2002[6]; Warpinski *et al.*,1998[7]). Progress has been made in developing numerical models to describe hydraulic fractures in recent years (e.g. Adachi *et al.*, 2007[8]; Dean & Schmidt, 2009[9]; Ji *et al.*, 2009[10]; Lecamplon & Detournay, 2007[11]; Liu *et al.*, 2015[12]; Vandamme & Curran, 1989[13]; Wu & Olson, 2013[14]; Zhang & Jeffrey, 2006[15]; Zhang & Ghassemi, 2011[16]; Zhang *et al.*, 2007[17]).

Many numerical approaches have been employed in order to investigate the initiation and propagation of hydraulic fractures; Mohammadnejad & Khoei (2013 1[18], 2[19]) used the extended finite element method applied to a cohesive crack; Hamidi & Mortazavi (2014)[20] used distinct element modelling; Weng *et al.* (2014)[21] introduce a complex fracture network model; Ding *et al.* (2014)[22] used a coarse grid technique; etc.

The above makes it clear that there is no universal mathematical approach to describing fracture initiation and propagation in shale, with researchers using different approaches.

With this in mind, this report will not outline a mathematical approach and will therefore only make general statements about the theoretical framework.

According to Griffiths (1921)[23] energy balance, a crack will propagate, when the energy release rate equals the crack resistance force. This theory was advanced by Irwin (1958)[24] who stated that a fracture will propagate at a critical stress, this can be referred to as the critical stress intensity factor. Each mode of fracturing has its own stress-intensity factor. In terms of the hydraulic fracturing process it is important to know the stress at which fractures in the shale will propagate and also the direction and magnitude of this crack growth. In classical fracture mechanics, the propagation of a fracture is controlled by the magnitude of fluid velocity near the fracture tip. The rate of propagation is controlled by the availability of water at the tip to create stress corrosion. The physical properties of the shale and the stress state of the particular shale will go a long way to governing the propagation of fractures.

At the crack tip in a rock, stress is concentrated and creates a process zone made up of small cracks. Coalescence of these small microfractures results in the formation of a macro-scale hydraulic fracture (e.g. Atkinson, 1987[25]). Thus the fracture propagation criterion can be reduced to a stress-based criterion. If the effective stress (considering the influence of the pore pressure) exceeds the critical traction stress (tensile strength), then the cohesive energy is fully dissipated and the fracture propagates further (Carrier & Granet, 2012[26]). The critical traction stress is the physical property of the rock formation and independent of the applied loading.

Once a microcrack has been initiated, propagation occurs in the direction that requires the least energy to fail. Mesoscopically, a fracture may appear to have propagated smoothly without stopping; microscopically, propagation is rapid and discontinuous, following many branches of microcracking (Engelder, 1992[27]). Larger scale discontinuities require the more energy-efficient process of microcrack communication and linkage. Under purely tensile conditions, a single microcrack can propagate into a large discrete discontinuity that can rupture the whole rock, whereas failure in compression requires linkage of many extensional and shear cracks. At the tip of a microcrack, the concentration of stress results in the creation of many small microcracks in a non-linear process zone. Microcrack communication lengthens the features, and propagates the process zone into the rock mass in the direction of the maximum compressive stress trajectory. Several processes control or influence discontinuity propagation, including elastic strain accumulation, crystal-plastic processes, diffusion processes, phase transformations and reactions, and fluid processes. Hydraulic fractures continue to propagate until the stress-intensity at the fracture tip is lower than the critical stress intensity of the rock being fractured (e.g. Savalli & Engelder, 2005[28]).

Several approaches have been proposed to quantify fracture width and/or length. One example is that of Haimson & Fairhurst (1967)[29], who proposed an analytical solution for fracture width given by:

$$W_{max} = \frac{4(1+\upsilon)}{3E} L(\sigma_3 + u_f)[2(1-\upsilon) - \alpha(1-2\upsilon)]$$

where W_{max} is the maximum fracture width, L is the fracture length, μ_f is the pore pressure at failure, ν is Poisson's ratio, E is Young's modulus, δ_3 is the minimum principal stress, and α is the Biot coefficient. This solution suggests that fracture width and length are proportional to one another. The width of propped fractures not only depends on the length of the fracture, but also on the amount of sand that is pumped (Khanna *et al.*, 2014[30]).

Observations of natural hydraulic fracturing

Richard Davies and co-workers (Davies *et al.*, 2012[31]) published a study on natural hydraulic fractures, which is useful in assessing the geometric extent of induced or stimulated hydraulic fracturing. Cosgrove (1995)[32] showed that natural hydraulic fractures can be observed in outcrops from the centimetre to metre scale. There are several types of natural hydraulic fracture that have all been extensively studied, including: injectities (e.g. Hurst *et al.*, 2011[33]), igneous dykes (e.g. Polteau *et al.*, 2008[34]), veins (e.g. Cosgrove, 1995[32]), coal cleats (e.g. Laubach *et al.*, 1998[35]), and joints (e.g. McConaughy & Engelder, 1999[36]). Savalli & Engelder (2005)[28] showed that growth of natural hydraulic fractures could be studied in the Devonian Marcellus formation in the US on the basis of plume lines that occur over a range of scales from centimetre to metre scale. The formation of these natural features is inferred to derive from gas diffusion and expansion within the shale during multiple propagation events.

The tallest example of natural hydraulic fracture result when they cluster and form chimneys (also termed pipes or blowout pipes). These have been observed to extend vertically for hundreds of metres (e.g. Cartwright *et al.*, 2007[37]; Huuse *et al.*, 2010[38]). Their origin is uncertain, but may result from critical pressurisation of aquifers and hydrocarbon accumulations (Zühlsdorff & Spieß, 2004[39]; Cartwright *et al.*, 2007[37]; Davies & Clarke, 2010[40]). Chimney development may be followed by fluid driven erosion and collapse of the surrounding rock (Cartwright *et al.*, 2007[37]). The release and expansion of gas from solution during advective flow may also play a role in development (Brown, 1990[41]; Cartwright *et al.*, 2007[37]). Chimneys are clearly identifiable in seismic data as vertical aligned discontinuities in otherwise continuous units (Cartwright *et al.*, 2007[37]; Løseth *et al.*, 2011[42]). Davies *et al.* (2012)[31] examined 368 chimneys from offshore Mauritania and showed that the average height was 247 metres, with the tallest chimney being 507 metres. In offshore Namibia 366 chimneys showed an average height of 360 metres, with the tallest being approximately 1,100 metres. In offshore Norway 466 chimneys showed an average height of 338 metres, with a maximum of 880 metres. From comparing natural with induced hydraulic fractures, Davies *et al.* (2012)[31] conclude that the probability of an induced hydraulic fracture extending vertically more than 350 metres is about 1%. It should be noted that their conclusion is based on fracture height statistics alone and the mechanistic basis for fracture height control is not taken into account.

Hydraulic fracture stimulation from a horizontal borehole is usually carried out in multiple stages with known volumes and compositions of fluid (e.g. Bell & Brannon, 2011[43]). Rather than chimney formation, clustering of fractures commonly occurs along planes, which are theoretically orthogonal to the least principle stress direction. Therefore fundamental differences exist in the geometry of these fracture systems compared to those that cluster to form chimneys, the reasons for which are not yet understood (Davies *et al.*, 2012[31]).

Observations of hydraulic fracturing during shale gas exploitation

Much of the research conducted on hydraulic fracture propagation in shale derives from modelling and interpretation of microseismic data from active shale gas plays. This type of data is recorded by geophones and tiltmeters, which are placed in shallow monitoring boreholes close to the active well. Microseismic data allow reservoir engineers to map where deformation has taken place. This data can be used to tailor the fracturing process to ensure safety and to maximize gas output. Microseismic data also allow geomechanical properties to be inferred for the shale and can be used to ascertain the stress regime around the borehole.

Fracture height

Fisher, King and Warpinski (Fisher & Warpinski, 2011[44]; King, 2012[45]) have published the most comprehensive research on observations of hydraulic fracturing during shale gas exploitation. They used microseismic data from thousands of fracture treatments carried out on the Barnett, Woodford, Marcellus and Eagle Ford Shale formations; these being some of the highest producing formations in North America. The largest vertical fracture observed had a vertical extent of 1,500 feet (457 metres) and occurred in the Marcellus shale. The largest mapped fractures tended to occur at the greatest depths. Fisher & Warpinski speculate that these are associated with the interaction with natural fractures. They observed that fractures grow much taller in the Marcellus than in the Barnett.

Fisher & Warpinski (2011)[44] present tiltmeter data from more than 10 000 fractures and examine the vertical and horizontal components of these fractures. The overall pattern is that fractures shallower than 4,000 feet (1,200 metres) are predominantly vertical whereas below this point the ratio between vertical and horizontal fracture growth is more complex. Fisher & Warpinski (2011)[44] discuss these patterns and conclude that the *in situ* stress and mechanical properties of the stratigraphy, such as variations in moduli and anisotropy associated with laminations, are the reasons why vertical fractures are hindered and lateral fracture growth is the preferred path of least resistance. Outside factors such as large faults in the area can lead to an increase in vertical fracture growth. This complex data set goes to show the complexities associated with fracture development and the mechanics driving fracture propagation in a heterogeneous layered rock.

Environmental concerns have been aired about the possibility of fracture growth vertically from a shale unit to overlying potable water aquifers. Fisher, King and Warpinski (Fisher & Warpinski, 2011[44]; King, 2012[45]) present data showing the depth of hydraulic fracturing, the maximum height of vertical fracture formation, and the deepest depth of potable aquifers for the Barnett, Eagle Ford, Marcellus and Woodford Formations; this data is summarized in Table 6. This data clearly shows that during 10 000 hydraulic fracture stimulations, the closest a vertical fracture came to the bottom of a potable aquifer was 2,800 feet (853 metres). Typically the distance was in the range 3,800 to 7,500 feet (1,158–2,286 metres).

Table 6 Fracture height-growth limits in 4 major US shale plays (King, 2012[45])

Shale	Fracs number with micro-seismic data	Primary pay zone depth range	Typical water depth (and deepest)	Typical distance between top fracture and deepest water	Closest approach of top of frac in shallowest play to deepest water
Barnett	3,000+	4,700’ to 8,000’	500’ (1,200’)	4,800’	2,800’
Eagle Ford	300+	8,000’ to 13,000’	200’ (400’)	7,000’	6,000’
Marcellus	300+	5,000’ to 8,500’	600’ (1,000’)	3,800’	3,800’
Woodford	200+	4,400’ to 10,000’	200’ (600’)	7,500’	4,000’

In situ stress

Microseismic and tiltmeter data can be used to infer the *in situ* stress conditions within the target shale. Busetti and co-workers (2014 1[46], 2[47]) use multi-array seismic data from the Barnett shale to determine the geomechanical conditions at the time of hydraulic fracturing. The locations of the microseismic outputs are often shown in a cloud map. The majority of fractures in this data set seemed to have propagated parallel to one another. The direction of these fractures was seen to be perpendicular to the minimum principal stress in the expected direction of the maximum principal stress (σ1), meaning Mode I fractures. Some fractures were inclined to σ1 suggesting natural fractures in the area may have also had a control over the fracture network.

Arrest and containment of fracture propagation

The physical properties of shale also have an effect on the arrest of propagation as well as the propagation. Smart *et al.* (2014)[48] used finite element modelling to simulate the effect of mechanical stratigraphy and other varying geological properties, such as stress state and the presence of naturally occurring faults. The model is based on a log of the Ernst Member of the Boquillas Formation in Western Texas; this is a stratigraphic equivalent of the Eagle Ford Formation. The varying strengths of the beds, which were identified by the Schmidt-Hammer technique, were used to represent a realistic stratigraphy. The model simulated fluid injection and predicted where fractures were likely to form. Several iterations of the model were presented showing the varying effects of stratigraphy and mechanical properties. They conclude that mechanical stratigraphy can exert a fundamental control on the pattern of hydraulic fracturing and only small variations in this stratigraphy can result in large changes in the observed fracture pattern. Although this model is only two dimensional it predicts that the fracture pattern will be complex, with propagation in many directions and interconnectivity of the fractures. It must be noted that this study used just one value for the Young's Modulus and Poisson's ratio, when it is likely that this would be heterogeneous. Laboratory measurements may be required to constrain this model further so that the mechanical stratigraphy is better represented.

Philipp *et al.* (2013)[49] combined field investigations and numerical modelling to conclude that heterogeneous stratigraphy can result in strata bound fractures. These fractures are more likely to be strata bound if the boundary between strata is abrupt as opposed to a gradual change in mineralogy. Philipp *et al.* (2013)[49] also state that strata with contrasting mechanical properties are also differently stressed, as a result of remote tension or compression, excess pore pressures or local stress from propagating hydro-fracture tips (Zang & Stephansson, 2009[50]). Variations in horizontal stresses are common within petroleum reservoirs (Economides & Nolte, 2000[51]). These heterogeneous local stress fields can act to control the propagation of hydraulic fractures. However, Philipp *et al.* (2013)[49] also state that as a network of hydraulic fractures develop in an area during the extraction process then the area may become more heterogeneous, resulting in a multi-layer system gradually becoming a single layer system and acting as one; meaning that it is only the mechanical stratigraphy which effects the initial hydraulic fracture emplacement.

As well as using microseismic data to predict fracture propagation in shales, laboratory experiments can also be used to examine fracture properties. The fracture toughness is a measure of a materials resistance to tensile fracture propagation. The fracture toughness can quantify the stress concentration at a crack tip at the point of fracture propagation. Fisher & Warpinski (2011)[44] suggest the heterogeneous nature of shale results in varying fracture toughness values which can act to halt fracture propagation. This theory is supported by laboratory fracture toughness data of the Woodford Shale which shows values in the upper Woodford shale to range from 1.15 to 1.17, whereas in the Lower and Middle Woodford Shale values range from 0.65 to 0.74. A higher quartz content is observed in the Upper Woodford shale, meaning the fracture toughness may be influenced by mineralogy. Therefore, not only does fracture toughness play a role in fracture initiation, it plays a controlling role in fracture propagation and arrest. Chandler *et al.* (2012)[52] investigated the fracture toughness of Mancos Shale using a modified Short Rod method, which involved the propagation of a crack through a triangular ligament in a chevron notched cylindrical sample (Ouchertlony, 1988[53]). Fracture toughness was measured in three directions to investigate anisotropy. A substantial anisotropy was observed, with values 25% higher in one direction. They also noted that the values recorded in this experimental set up are 1.5–2-1 higher than other published results, implying the material also varies within the formation.

Hydraulic fracture characterization

Despite a wealth of data on microseismic observations and the corresponding modelling of these, little is known about the actual characteristics of the hydraulic fractures; such as fracture density, topography and width. These are all important characteristics which would allow reservoir engineers to more accurately predict production levels. In absence of this information, many studies have used a description known as the Specific Reservoir Volume (SRV) to describe the volume of rock which has been affected by the injection of the fracturing fluid (Mayerhofer *et al.*, 2006[54]; 2008[55]). This is deduced from the spread of microseismic data and assumes that all of the seismic outputs are associated with connected fractures. Recent studies have begun to attempt to improve the calculation and interpretation of the SRV as these assumptions do not give enough information on the fracture network and connectivity (Yin *et al.*, 2015[56]; Cipolla & Wallace, 2014[57]).

Physical properties

Maxwell (2011)[58] studied microseismic data from the Montney shale and correlated these to geophysical measurements of the rock. They notice a higher number of microseismic responses in areas with lower Poisson's ratio, they also note that the density of microseismic responses may be used to estimate a produced fracture density. This type of information can be used to better focus the injection of fracturing fluid to areas which are likely to form a higher fracture density.

Concluding remarks on fracture propagation

Fisher & Warpinski (2011)[59] highlight the need to understand the geology surrounding the target area in order to estimate the direction of fracture propagation. Their concluding remarks clearly asses the current state of understanding:

> *"The directly measured height growth is often less than that predicted by conventional hydraulic-fracture propagation models because of a number of containment mechanisms… Some of those mechanisms include complex geologic layering, changing material properties, the presence of higher permeability layers, the presence of natural fractures, formation of hydraulic-fracture networks, and the effects of high fluid leak-off."*

> *"Fracture physics, formation mechanical properties, the layered depositional environment, and other factors all conspire to limit hydraulic-fracture-height growth, causing the fracture to remain in the nearby vicinity of the targeted reservoirs."*

Knowledge gaps and recommendations

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

- Shale is a highly variable and heterogeneous material. Both variability and heterogeneity need

to be better understood and incorporated into numerical models.
- Many numerical approaches exist; modelling should work towards a unified approach of describing fracture propagation in shale.
- Numerical models tend to over-predict the length of hydraulic fractures that are formed. The understanding of fracture arrest in a complex geological unit, such as shale, needs to improve to better numerically represent the hydraulic fracturing process.
- Experimental observations are needed on fracture propagation in a complex, layered shale in order to identify the controls of fracture deviation and/or arrest.
- A better understanding of the mineralogical control on fracture propagation is required.
- Shale does not behave as a perfect elastic medium and as a result numerical models need to incorporate the full thermo-hydro-mechanical-chemical behaviour of the rock. This is, however, currently computationally time consuming.
- A close relationship is required between drilling engineers, experimentalists and numerical modellers in order to improve the understanding of a complex system.
- Many studies have been conducted that consider shale as a uniform, homogenous, elastic material. Whilst complexity is difficult to incorporate within numerical models, representative physics is required with good ground truth field data.
- A wealth of empirical field observations in North America is now available that should help to improve the understanding of the physics controlling fracture propagation.
- Modelling scenarios are required on European shale using well constrained approaches demonstrated in the United States to predict the behaviour of European shale plays.

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