Geomechanical and petrophysical properties of mudrocks: introduction

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Abstract: Mudstones (shales) are of particular importance as the source rocks for oil and gas, and increasingly so as the reservoirs for unconventional hydrocarbons. They are also the most common sedimentary rocks on Earth, and, hence, are frequently encountered in excavations and foundations for buildings. These factors point to a pressing need to develop an increased fundamental understanding of their geomechanical and petrophysical properties. The mineral content of mudstones has a dominant effect on their mechanical properties. Presence of clay minerals within them results in plasticity and ductility that can pose particular engineering challenges, but swelling clays in particular can lead to serious problems of mechanical stability of boreholes and in construction. Good hydraulic fracture performance is linked to brittleness and high elastic moduli. This in turn is favoured by high silica or carbonate content and diagenetic cementation. Permeability to fluids depends on the interconnectivity of storage pores through orientated crack networks. New advances in imaging technologies are permitting very-high-resolution three-dimensional imaging down to the nanometre scale. Such studies will eventually lead to technological advances that exploit more effectively these enigmatic rocks.

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A surge of interest in the geomechanics and petrophysical properties of mudrocks (shales) has taken place in recent years following development of the shale gas industry in the USA and elsewhere, and with the prospect of similar developments in the UK. Also, these rocks are of particular importance in excavation and construction geotechnics and other rock engineering applications, such as underground natural gas storage, carbon dioxide disposal and radioactive waste storage. The fact that mudrocks make up almost three-quarters of all sedimentary rocks on Earth, and impact on so many areas of applied geoscience, means that there is a range of definitions and descriptions applied to these rocks according to the points of view of different groups of scientists.

Compared to most other rock types, geomechanical and microstructural studies on mudstones are more demanding owing to their fine grain size, complex mineral assemblages and microstructure. They are often friable and well foliated, leading to difficulties in handling and machining, and they can be particularly sensitive to wetting and desiccation. The development of industries that work with mudrocks, such that they are efficient and satisfy public concerns about safety, demands that the fullest possible understanding of the mechanical and petrophysical behaviour of these rocks be obtained.

This Special Publication arises from a meeting of the same title held at the Geological Society of London in November 2015, under the auspices of the Tectonic Studies Group of the Geological Society and the Clay Minerals Group of the Mineralogical Society. The 15 papers in the volume have been organized into three themes: Petrophysical properties; Microstructure and mineralogy; and Fracture. This introductory chapter aims to set these contributions into the overarching scope of the geomechanics and petrophysics of mudrocks.

Terminology

Mudstones are very-fine-grained clastic sedimentary rock with particle sizes dominantly smaller than 64 μm (Potter et al. 2005). Lazar et al. (2015) provided a practical geometrical/mineralogical scheme for the classification and description of mudstones. The primary divisions are based on grain size. Coarse mudstones can be called siltstones, and fine mudstones are also called claystones, whether or not clay mineral particles dominate. Subsequent qualifications are applied based on forms of layering or lack of it, and finally on mineral modal composition. Milliken (2014) attempted a new classification based on composition and origins of grains, but it is
rather less straightforward to apply because some interpretation is required to arrive at the basic description (Camp et al. 2016).

Mineralogical characteristics are likely to exert the greatest influence on the geomechanical and petrophysical properties of mudstones (strength, fracture toughness, cohesion, plasticity, ductility, brittleness, elasticity). The dominant mineral components are quartz (+ feldspar and pyrite), various clay minerals and detrital micas, and carbonate minerals in varying proportions, which means that dominant mineral contents can be graphically represented on a ternary diagram with these as end members (Fig. 1) (Sone & Zoback 2013a; He et al. 2015). Most mudstones occupy the middle third of the range between quartz/feldspar and clay mineral dominance, with a large population extending towards the carbonate corner. An important component, comprising commonly up to 5 wt%, but sometimes much more, is organic carbon as kerogen or bitumen particles. Diagenetic changes during burial and heating cause these to degrade into oil and gas; thus, mudstones are typically the source rocks for conventional oil and gas accumulations. A significant amount may remain trapped in the source rock, however, and can be exploited as unconventional hydrocarbons. Diagenetic pyrite is often present in mudstones, comprising up to 5 wt%. Significant mineral products of diagenetic alterations include anhydrite as cement grains, layers and nodules, and selenitic gypsum.

Reviewing the role of mudrocks in geotechnics, Cripps & Czerewko (2017) consider issues of the relationships between mineral composition, rock structure and geotechnical properties. Wilson et al. (2017) point out that the presence of certain clay minerals in a mudstone can be a primary cause of mechanical instability, whether of wellbores, slaking of drill cuttings leading to pipework blockages or low friction leading to slope instability. They discuss the origins of these and other problems from the standpoint of the fundamental physicochemical properties of these minerals.

**Burial and compaction**

Flocculation of clay minerals leads to primary depositional porosities in mudstones greater than that expected of equigranular particles of quartz, feldspar and carbonate minerals (Schieber et al. 2013). Primary porosity may be greater than 60% with no preferred orientation of clay platelets (Potter et al. 2005). Progressive burial rapidly causes mechanical compaction, collapsing platy minerals towards a common, bedding parallel alignment, but with deflections around stiff silt particles, and rapidly reducing porosity and permeability (Dewhurst

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**Fig. 1.** Comparison of modal compositions of several gas-bearing shales. Whitby and Bowland shales are in the UK: the remainder are in the USA. American data are replotted after Sone & Zoback (2013a) and He et al. (2015). Bowland shale data after Fauchille et al. (unpublished data), and Whitby shale composition from McKernan et al. (2017).
Porosity is typically reduced to approximately 25% by 600 m of burial. Figure 2 shows experimental mechanical compaction of a water-saturated mixture of 33% kaolinite and 40\% quartz under an axisymmetrical load with no lateral expansion allowed \((k_o\text{-loading path})\) (Rutter et al. 2013a). Mackey & Bridge (1995) show curves for a decrease of porosity with burial depth for mudstones that compare favourably with such simple mechanical tests. It appears impossible to reduce porosity below about 24\% by mechanical compaction alone, but the implied 60\% vertical shortening represents an extremely high strain and is sufficient to produce quite a strong planar fabric and some orientation of platy particles. The term ‘shale’ is usually reserved for fissile mudstones with a strong bedding-parallel fabric.

Chemical compaction involves the time-dependent further elimination of porosity by thermally-assisted creep processes, volume changes arising from diagenetic reactions, pressure solution and cementation, eventually reducing porosity to less than 10\%. Rutter & Wanten (1999) investigated experimentally the kinetics of these processes by trading time for elevated temperature and obtained a compaction law. Aplin et al. (2006) studied the development of the clay mineral fabric of Pliocene sediments recovered from a depth range of 1.8–5.8 km, using X-ray texture goniometry. They demonstrated clay basal orientation of about 3 multiples of a uniform distribution and little variation over that depth range, despite porosities being reduced to about 10\%. It is common to find delicate spheroidal diagenetic pyrite frambooids in most shales, superimposed on the compacted fabric, again indicating that most compaction and fabric development is achieved early in the burial history of mudstones.

Mature gas shales tend to display higher porosities for higher contents of clay + organic matter (Sone & Zoback 2013b).

**Evolution of porosity and microstructure**

Advances in imaging techniques beyond optical petrography and conventional scanning and transmission electron microscopy (Sondergeld et al. 2010) have led to the application of a range of new techniques to the study of shales, including surface preparation using a focused ion beam for improved SEM imaging (Ambrose et al. 2012; Houben et al. 2017), X-ray tomographical imaging and synchrotron X-ray imaging (Khalili et al. 2012; Ma et al. 2016). The last of these allows in situ experimentation during imaging. High-quality, 3D high-resolution images can form the basis for computation of petrophysical properties, such as pore size distribution and permeability (Savatorova et al. 2016; Figueroa Pilz et al. 2017) (Fig. 3). In this volume, Ma et al. (2017) review the latest applications of imaging techniques to shales and the correlation of microstructural features imaged from the millimetric to the nanometric scales.
The measurement of porosity of shales may not be straightforward. Busch et al. (2017) describe the application of multiple techniques of porosity determination to a suite of Opalinus Clay samples from the Mt Terri Underground Rock Laboratory in Switzerland. The variability of apparent porosities obtained can be attributed to the fact that different methods may be measuring different things, attributable in large part to different degrees of pore accessibility from outside the specimen.

Pore-system characterization can be carried out by means of gas or vapour adsorption measurements at pressures up to the saturation pressure. Gas adsorption measurements allow access to pore sizes down to smaller than 10 nm (e.g. Ma et al. 2016, using nitrogen). In this volume, Seemann et al. (2017) point out the advantages of using water vapour as a molecule to probe fine pore structure and apply it to a suite of 13 different mudrocks.

Elastic properties, strength, brittleness and plasticity

A comprehensive overview of elastic properties and their anisotropy for several North American shales is provided by Sone & Zoback (2013a), reinforcing and extending earlier work of Hornby et al. (1994), Hornby (1998), Johnston & Christensen (1995), Sondergeld & Rai (2011), Vernik & Nur (1992) and Chang et al. (2006). Shales are usually found or assumed to display transverse isotropy. The differences between bedding-normal and bedding-parallel elastic properties vary widely but depend strongly on their composition, tending to be more anisotropic with increasing clay and organic content (Fig. 4) (Sone & Zoback 2013a). Young’s modulus values for a range of shales vary between about 20 and 80 GPa, tending to be softer with increasing clay and organic content. Stiff shales are as stiff as typical granites.

The nature of the clay minerals in a mudrock can be of particular importance. The presence of smectites can lead to particular engineering challenges. Weakly consolidated mudrocks bearing swelling clays are prone to weakness and instability through their capacity to adsorb water and gases that can be squeezed out when subjected to loading. In this volume, Wentink & Busch (2017) describe the instability that can arise from stresses induced by swelling of smectite through CO₂ absorption in the cap rock above a gas storage reservoir.

Sone & Zoback (2013a) also presented an overview of the strength and ductility of a number of shales, their relationships to composition and to elastic properties. They reported a strong correlation between mechanical properties and composition, with clay + organics-rich samples being weaker and more ductile in creep experiments. Ease of creep deformation is expected to facilitate closure and healing of hydraulically-induced fractures. Samples were observed to fail by brittle faulting, with a marked sensitivity of strength to confining pressure. Friction coefficients for sliding on the rough fault surfaces produced lay between 0.5 and 0.8. As shown by Rutter & Mecklenburgh (2017) in this volume, the friction sliding coefficient depends on the roughness of the slip surface. Smoother surfaces display a progressively lower friction coefficient, attributed to smearing of clays and organic matter over the slip plane.

Rybacki et al. (2015, 2016) carried out a similarly wide-ranging comparison of the mechanical behaviour of several relatively clay + TOC (total organic carbon)-rich European shales, over a range of confining pressures and temperatures. Although increasing confining pressure favoured a general transition from brittle to more ductile failure, a combination of high porosity and higher clay content favoured ductile deformation, and a lower sensitivity of strength to confining pressure.

Brittleness is regarded as a rock property that facilitates hydraulic fracturing and affects optimum mud weight for borehole stability. Brittle rocks are strong, stiff and creep-resistant (Hucka & Das 1974; Holt et al. 2011; Guo et al. 2013; Rybacki et al. 2016). There is no unique measure and various parameters have been proposed to characterize brittleness, some based purely on compositional end members, others on elastic parameters, pre-failure strain, or on an empirical relationship between unconfined compressive and tensile strengths, the mode I fracture toughness or the parameters of the...
Mohr–Coulomb failure criterion, all according to degree of water saturation. Rybacki et al. (2016) compared a wide range of such parameters and evaluated their relative usefulness, but without coming to a clear and unambiguous conclusion regarding a preferred measure.

Mineralogy

Experimental determinations of fracture mechanics parameters (fracture toughness, subcritical crack growth index) are being carried out increasingly for shales (e.g. Chong et al. 1987; Thiercelin 1989; Warpinski & Smith 1990; Gale et al. 2007; Lee et al. 2015; Chandler et al. 2016), although published data are overall very few. Fracture toughness is a measure of the resistance to propagation of a single brittle crack, and is defined in such a way that the measure is independent of the loading configuration when the measurement is made, unlike tensile strength, for example. The concept of fracture toughness is applied to the design and modelling of large-scale hydraulic fracturing, for hydrocarbon recovery or for in situ stress determinations (Shlyapobersky et al. 1988; Adachi et al. 2007; Li et al. 2016). In laboratory-scale experiments, the material toughness may be a dominant factor and be measurable even when the fracture is driven by a very viscous fluid, but in field measurements the fracture toughness value may be dominated by factors such as the compressibility of and the viscous pressure drop in the pumped fluid, the development of a gap (lag) between the fracture tip and the injected fluid front, and likely but generally unknown geometrical complexity of the form of the propagating fracture(s) (e.g. Garagash & Detournay 2000; Bungers et al. 2005; Garagash 2006). There remains a disconnect between the measurements of fracture mechanics parameters in the laboratory and their application in the field as crack growth proceeds (Papanastasiou 1999).

The interpretation of the breakdown pressure required to initiate a hydraulic fracture remains contentious. It is likely to depend on whether the hydraulic fluid can infiltrate the wall rock and whether there is any existing damage to the borehole wall to facilitate the start of a hydraulic crack. In situ breakdown pressure can be unexpectedly large (e.g. Guo et al. 1993) or can be comparable to the value of in situ least principal stress (Oldenburg et al. 2017). In laboratory tests under hydrostatic far-field stresses, it may be comparable to the expected value of twice the confining pressure (Li et al. 2016) or sometimes rather greater (e.g. Rutter & Hackston 2017).

Laboratory measurements will provide an essential basic understanding of the breakdown processes at crack tips and the relationship to material anisotropy. In this volume, Chandler et al. (2017) present new data on the temperature and orientation dependence of fracture toughness of Mancos shale compared with other rocks. As with sandstone, limestone and granite, the influence of temperature variation over the entire range of reservoir temperatures is small. For the shale, the orientation of the propagating crack results in a toughness variation of more than a factor of 2, and this anisotropy is preserved over the full range of temperature investigated.

Fluid storage and transport

Fluid storage in shales is accommodated as free fluid in pore spaces, in which case the quantity of fluid stored depends on the porosity and the fluid pressure together with its compressibility. Pore fluid pressures generally increase with depth of burial and are limited by leak-off into hydraulic fractures that can develop when the pore pressure exceeds the least principal stress. Thus, in the case of gas in particular, more deeply sourced gas is present in greater amounts for a given porosity owing to its greater compressibility than that of liquids. Amount of gas-in-place is usually cited as the volume to which it expands when released to surface temperature and pressure, and this is how gas reserves are usually cited, a point that is often not appreciated even by hydrocarbon geologists.

Free gas in pore spaces is, however, augmented by gas that is strongly adsorbed onto the surface of maceral particles and, to a lesser extent, clay minerals (Kang et al. 2011; Ambrose et al. 2012). Such gas begins to be released when the gas pressure falls below the critical desorption pressure (GRI 1996; Ross & Bustin 2007), which is of the order of 13 MPa, and helps to extend the life of a reservoir. Total gas-in-place calculations must include both free and adsorbed gas. Adsorbed gas density may approach the liquid density (Tsai et al. 1985), so that adsorbed gas can account for as much as one-third of the total gas-in-place. Gensterblum et al. (2015) provided a comprehensive review of gas storage and transport in shale reservoirs.

The measurement of porosity of shales is not as straightforward as for other rock types. Recovery, storage and handling of samples needs particular care, especially where fracturing through drying or swelling as a result of wetting can occur, and different methods of porosity determination can yield different results: that is, they do not all measure the same thing.

Transport of fluids (liquids and gases) through shales takes place by permeation through the matrix of connected pores, augmented by flow through any network of macrocracks that may exist. Several of
the papers in this volume deal with aspects of fluid storage and flow through shales. Both gas storage and yield via matrix permeation is sensitive to the degree of saturation by liquids in the pore space. Partial liquid saturation reduces pore space for storage and density of transport pathways. Eventually, it gives rise to a capillary entry pressure that must be overcome for gas flow to take place (Schmitt et al. 1994; Hildenbrand et al. 2002, 2004).

Viscous flow according to Darcy’s law is the dominant mechanism of fluid transport through the pores of conventional reservoir rocks, but in mudstones and other tight rocks, in which pores and pore throats are generally of sub-micron dimensions, gas slippage at pore walls may enhance transport rate at low gas pressures, and lead to deviations from Darcy’s law (Klinkenberg 1941). The magnitude of the dimensionless Knudsen number (the ratio of the molecular mean free path length of the gas molecules, \( \lambda \) (in m), to the characteristic length of the porous medium (the mean pore width)), indicates the flow regime occurring in the porous medium. Darcian laminar flow is characterized by a small Knudsen number, as when gas pressures are high (mean free path small) and pore widths are large. During production from gas reservoirs, flow enhancement through the gas-slippage effect can become important at gas pressures smaller than about 10 MPa, such as during the final stages of production when pressures as low as 1 MPa may be reached (Holditch & Morse 1976; Clarkson et al. 2012; Swami et al. 2012).

Permeability may be measured in the laboratory using steady flow techniques, although this will typically result in very long duration experiments (Cuss et al. 2014). Transient flow techniques, such as the pulse transient decay method (Brace et al. 1968; Jones 1997; Yang & Aplin 2007) or oscillating pore pressure technique (Turner 1958; Kranz et al. 1990; Fischer 1992; Faulkner & Rutter 1998; Bernabé et al. 2006; Song & Renner 2007), may alternatively be used. The so-called GRI (Gas Research Institute) method (Luffel et al. 1993) employs crushed samples and cannot be used over a range of confining pressures nor can anisotropy effects be investigated. Mercury injection curves from porosimetry can also be used to infer permeability (Swanson 1981). Cui et al. (2009) compared different approaches to permeability measurement, including the effects of adsorption on such measurements.

Dependence of permeability on effective pressure and other factors

Many studies have demonstrated that permeability of mudstones decreases with Terzaghi effective confining pressure (total confining pressure \( P_c \)) minus pore fluid pressure \( (P_p) \)), usually with log permeability \( k \) decreasing linearly with effective pressure or log effective pressure (Kwon et al. 2001; Yang & Aplin 2007; Heller et al. 2014). Alternatively, this can be expressed as: \( \log k = A - B(P_c - \alpha P_p) \), where \( A \) and \( B \) are constants, in order to draw attention to any difference between the way that total applied pressure and pore pressure affect permeability. \( \alpha = 1 \) when the pore pressure is totally effective, or less than 1 if not fully effective. \( \alpha \) may exceed 1 if, for example, solid components (clay minerals, kerogen particles, partial liquid saturation) in the pore spaces are more compressible than the matrix of load-supporting grains (Seeburger & Nur 1984; Kwon et al. 2001; Al-Wardy & Zimmerman 2004). For clay-bearing sandstones, Zoback & Byerlee (1975) and Walls & Nur (1979) measured values of \( \alpha \) between 1 and 7.1. For a variety of mudstones, Heller et al. (2014) measured values of \( \alpha \) between 0.15 and 0.85, whilst Kwon et al. (2001) measured values of \( \alpha \) close to 1. The parameter \( B \) describes the rate of decrease of log permeability with effective pressure, and is likely to be of the order of magnitude over the typical range of reservoir pressures.

These issues of pressure dependence are discussed in this volume by McKernan et al. (2017), based on experiments on Whitby mudstone. The in situ estimation of permeability, gas-in-place and likely yield from drill stem tests typically neglects the pressure sensitivity of these parameters resulting from drawdown of gas pressure in a reservoir during production. This is despite an increasing body of experimental data that demonstrates that it should be taken into account when interpreting such test results, otherwise a severe overestimation of their values will occur (Rutter et al. 2013b; McKernan et al. 2014).

Fink et al. (2017) come to similar conclusions from a study of the dependence of permeability and porosity of the Jurassic Bossier shale (Texas) on effective stress. Because the pore system is dominated by crack and slit-like pores of low aspect ratio that are closed easily, even the porosity is very pressure-sensitive. This results in a corresponding pressure sensitivity of permeability.

Whilst the sensitivity of permeability to effective pressure can only be determined directly through laboratory measurements, it may be possible to estimate it indirectly from the pressure dependence of acoustic wave velocities, as McKernan et al. (2017) show in this volume. The closing down with progressive increase in pressure of thin, crack-like, bedding-parallel pores that control permeability is also detected through the pressure sensitivity of the velocity of P-waves propagating normal to bedding. The degree of sensitivity observed cannot
be explained by pressure-induced changes in the sizes of larger, more equant pores that dominate measured porosity; hence, there is no simple relationship to be expected between permeability and total porosity. Indeed, in their study of the relationships between pore structure and permeability in the different facies of the Opalinus Clay and its potential as a host rock for radioactive-waste disposal, Philipp et al. (2017) find that samples with the highest helium porosity display the lowest permeability. This implies that other microstructural parameters exert a greater influence on permeability than does bulk porosity.

Thick formations of clay-bearing mudstones offer properties that make them attractive as host rocks in nuclear waste repositories: for example, low permeability and molecular diffusion rates, and the ability to retain radionuclides, yet be able to vent safely gases (particularly hydrogen) produced in corrosion reactions. Harrington et al. (2017) describe experiments on a Jurassic mudstone considered suitable for repository construction, and show that when water-saturated the rock allows channelized flow through fissures to occur, at gas pressures much less than the minimum principal stress.

Like the importance of matrix permeability in the production of gas from shales of low organic content, the production of coal bed methane is very sensitive to changes to the permeability of coal that can result from geochemical interaction with drilling and fracturing fluids. In this volume, Cuff et al. (2017) explore the adverse chemical and mineralogical consequences of such interactions, and suggest how optimal choice of drilling fluids can mitigate against such formation damage.

Permeability and acoustic wave anisotropy

The microstructural anisotropy of shales is reflected markedly in anisotropy of permeability (Dewhurst et al. 1996; Clennell et al. 1999; McKernan et al. 2014, 2017), not so much because of the alignment of clay minerals but via enhanced flow through oriented microcracks. Permeability parallel to the layering in naturally-compacted shales is usually one, two or even three orders of magnitude greater than across the layering, and typically goes hand-in-hand with acoustic wave velocity anisotropy of the rock (Jones & Wang 1981; Sayers 1994; 2005; 2013; Johnston & Christensen 1995; Vernik & Liu 1997; Bonnelye et al. 2017; McKernan et al. 2017). Deposition, burial and compaction in a laterally extensive sedimentary basin are believed likely to result in a transversely isotropic fabric: that is, possessing an axial symmetry direction normal to bedding, with isotropic physical properties in the plane of the layering (Sayers 2005). Along the unique axis, values of acoustic velocity and permeability are generally smaller than parallel to the layering. Electrical resistivity is similarly affected.

Microstructural anisotropy arises from:

- Fine-scale layering of mineral components arising from sedimentation and compaction, that may be further enhanced through diagenetic reactions. Fluid flow is therefore easier along granular layers perhaps rich in quartz, whilst flow may be inhibited across the layering by low-permeability, phyllosilicate-rich layers. Certain layers may be enriched in equigranular or flat-topped organic particles that are known to possess fine-scale conductive porosity.
- Crystal form and, hence, crystallographic preferred orientation of petrographic minerals, detrital micas and clay minerals, leading to intergranular pores having bedding-parallel elongation.
- Microcrack formation is likely to be favoured parallel to the bedding fabric because fracture toughness is lower than across the planar fabric (Chandler et al. 2016).

Crack conduction

Hydraulic conductivity of natural cracks in shale is poorly understood (Engelder & Lacazette 1990; Gale et al. 1990; Cuss et al. 2011). The fractured state of shales at the Earth's surface is strongly enhanced by natural jointing from stress relief, and fracturing induced through oxidation reactions during weathering and cycles of drying and resaturation. It may tell us little about the fractured state at depth, the frequency of fractures, their sizes and apertures. Because shales typically have some capacity for creep, fractures may heal progressively with time unless they are propped open. If the distribution of cracks can be inferred or otherwise determined, numerical modelling can be used to determine the fluid-flow characteristics of the cracks + matrix composite (Matthai & Belayneh 2004).

It is well known that an increase in effective stress normal to a fracture dramatically reduces crack conductivity through aperture reduction and crushing of asperities. In this volume, Rutter & Mecklenburgh (2017) show from laboratory experiments that an increase of normal stress over the range of reservoir effective pressures may reduce conductivity of bedding-parallel cracks by up to two orders of magnitude, but also that a subsequent increase in shear stress up to the onset of frictional sliding reduces it further (more than 10-fold) through the formation of a small amount of fine-grained gouge smeared along the fracture. Minor slip along bedding planes therefore enhances permeability anisotropy.
A single fracture may typically have the same fluid transport capacity as a 1 m-thick layer of rock matrix. Hence, more than one crack per metre may be required for crack flow to dominate fluid transport capacity. Thus, unless pre-existing cracks are reopened by hydraulic stimulation, they may not greatly enhance the capability for gas transport through the rock mass. Shales appear to be remarkably effective seals for liquids and gases.

It is widely held, but not well substantiated, that rougher fractures cutting across bedding may be dilatant (Lee & Cho 2002), although Gale et al. (2007) and Gale & Holder (2010) found that small fractures in Barnett shale are frequently sealed by mineralization.

Interpreting mechanical behaviour at the reservoir scale

Two papers in this volume deal with the application of rock mechanics to situations encountered at the reservoir scale. Harper (2017) reports a series of numerical simulations of a naturally fractured shale gas reservoir to investigate how a sequence of hydraulic fractures might affect shear displacements on a fault.

Westaway (2017) revisits the case of the Preese Hall exploratory shale gas well in NW England. This was drilled in 2011 and the hydraulic fracturing experiments caused a sequence of about 50 small induced tremors, inferred to be caused by injection of pressurized hydraulic fracturing fluid into a nearby fault plane. The events led to a temporary moratorium on hydraulic fracturing in the UK. The extreme rarity of such events is underlined by the fact that subsequently tens of thousands of shale gas wells, each with multiple hydrofracture stages, were drilled in the USA without causing induced seismicity. Since 2011, the Preese Hall events have been the subject of several published studies (de Pater & Baisch 2011; de Pater & Pellicer 2011; Harper 2011; Clarke et al. 2014; Westaway 2016). Westaway (2017) presents a new conceptual model in which a key component is the existence of an extensive bedding-parallel deformed zone linking the borehole to the hypocentral region of the seismicity.

Shales and related rocks present challenges to understanding their mineral assemblages, microstructure, diagenetic evolution, petrophysical and mechanical properties. Amongst all naturally occurring rock types, these are the most complex, yet they are the commonest among the gamut of sedimentary rocks. Their growing economic importance and the need to be able to work with them from a geotechnical perspective is providing a growing scientific stimulus, such that more research is being carried out on these rocks than ever before. It is hoped that the research presented in this volume will provide a significant contribution towards that effort.

References


INTRODUCTION


INTRODUCTION

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