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"Basin scale" versus "localized" pore pressure/stress coupling – Implications for trap integrity evaluation

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ABSTRACT

In petroleum industry, the difference between pore pressure (P_p) and minimum horizontal stress S_h (termed the seal or retention capacity) is of major consideration because it is often assumed to represent how close a system is to hydraulic failure and thus the maximum hydrocarbon column height that can be maintained. While S_h and P_p are often considered to be independent parameters, several studies in the last decade have demonstrated that S_h and P_p are in fact coupled. However, the nature of this coupling relationship remains poorly understood. In this paper, we explore the influences of the spatial pore pressure distribution on S_h/P_p coupling and then on failure pressure predictions and trap integrity evaluation. With analytical models, we predict the fluid pressure sustainable within a reservoir before failure of its overpressured shale cover. We verify our analytical predictions with experiments involving analogue materials and fluids. We show that hydraulic fracturing and seal breach occur for fluid pressure greater than it would be expected from conventional retention capacity. This can be explained by the impact of the fluid overpressure field in the overburden and the pressure diffusion around the reservoir on the principal stresses. We calculate that supralithostatic pressure could locally be reached in overpressured covers. We also define the retention capacity of a cover (*RC*) surrounding a fluid source or reservoir as the difference between the failure pressure and the fluid overpressure prevailing in shale at the same depth. In response to a localized fluid pressure rise, we show that the retention capacity does not only depend on the pore fluid overpressure of the overburden but also on the tensile strength of the cover, its Poisson's ratio, and the depth and width of the fluid source.

1. Introduction

Abnormal pore fluid pressures are commonly encountered at depth in most sedimentary basins. Many signs indicate that these fluid overpressures could locally reach some extreme values, close to, or even in excess of the lithostatic pressure (Mouchet and Mitchell, 1989; Osborne and Swarbrick, 1997; Tingay et al., 2009). Hydraulic fractures, pipes, pockmarks sandstone intrusions (dykes or sills) or mud volcanoes (Berndt, 2005; Bünz et al., 2003; Chapron et al., 2001; Cowley and O'Brien, 2000; Deville et al., 2006; Gay et al., 2006a, 2006b; Graue, 2000; Jamtveit et al., 2004; Jolly and Lonergan, 2002; Kopf, 2002; Loncke et al., 2004; Planke et al., 2003) are some geological features that require high pore fluid pressures to form (Anderson, 1951; Hubbert and Willis, 1957; Secor, 1965). All these structures have strong consequences on the hydrodynamics of basins because they are pathways for pore fluids including hydrocarbons (Berndt, 2005). Pipes and pockmarks are sometimes considered as good indicators for petroleum potential, but may also indicate that the traps have been breached and that hydrocarbons expelled from the reservoirs (Loseth et al., 2008, 2001; Seldon and Flemings, 2005). The prediction of fluid pressure required for their formation then becomes an important issue in the evaluation of cover integrity.

Many leakage structures form by hydraulic fracturing of the overburden and result from localized pore fluid pressure build up within reservoirs (sand body) (Gay et al., 2006a; Loseth et al., 2008) or in the vicinity of a fluid source (for example, at the top of faults that conduct fluids, a process that has been termed 'vertical transfer' (Cole et al., 2000; Gay et al., 2006a, 2004; Tingay et al., 2007; Tingay et al., 2009; Yardley and Swarbrick, 2000))(Fig. 1). The development of overpressure within reservoirs requires the reservoir to be isolated by a low permeability formation, generally a shale which is also often already overpressured. These overpressures in overburden are distributed at basin scale and result from several mechanisms, mostly controlled by the depth and the rate of burial. Amongst possible causes, the most popular is the vertical compaction (referred as compaction disequilibrium).

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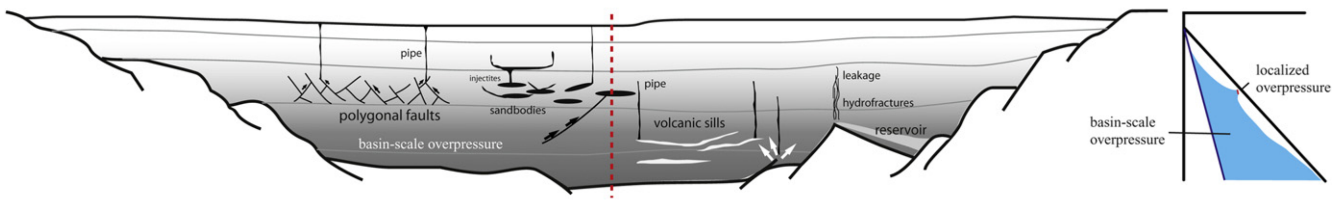

Fig. 1. Some geological features that require high pore fluid pressures to form. Compaction disequilibrium, mineralogical reaction or hydrocarbon generation are some mechanisms that develop fluid overpressure extending at basin scale. Such "basin-scale fluid overpressure" leads to horizontal hydraulic fractures that favour horizontal fluid migration. Fluid overpressure can also be localized in sand reservoirs, at the top of faults that conduct fluids or near magmatic intrusions. These localized pore overpressure create hydrofractures that favour vertical leakage (e.g. pipe, vertical hydrofractures…).

Compaction disequilibrium commences at the 'fluid retention depth', when low permeability sediments are unable to expel pore fluids (reduce porosity) fast enough to compensate for the increasing vertical stress associated with burial. Pore pressure increase due to compaction disequilibrium is typically parallel to the lithostatic gradient (Mouchet and Mitchell, 1989; Swarbrick and Osborne, 1996). Secondary mechanisms, such as hydrocarbon maturation or mineralogical reactions, may provide additional pore pressure (Osborne and Swarbrick, 1997).

For tensile hydraulic failure (mode I) and seal breach, the pore fluid pressure must exceed the minimum principal stress (S_3) and the tensile strength (T) of the overburden (Cosgrove, 2001; Jaeger and Cook, 1969; Sibson, 2003):

$$P_p > S_3 + T \tag{1}$$

If T is known and S_3 is estimated, it is common to calculate the maximum fluid pressure being sustained before failure of the sealing sediment and leakage, using equation (1). The difference between pore pressure and minimum horizontal stress (assuming $T = 0$) is a major consideration in petroleum exploration because it limits the height of hydrocarbon column that can develop (Finkbeiner et al., 2001; Flemings et al., 2002; Hillis, 2003; Lupa et al., 2002; Seldon and Flemings, 2005; Stump and Flemings, 2000) and it defines the retention capacity of traps (Gaarenstroom et al., 1993). Conventional understanding of brittle failure induced by increasing pore pressure assumes that total minimum stress S_3 is unaffected by changes in pore pressure (Cosgrove, 2001; Grauls, 1999). This assumption may be reasonable in some circumstances, such as triaxial laboratory tests, but its validity is questionable in natural examples where pore fluid is overpressured (Hillis, 2001, 2003; Mourgues and Cobbold, 2003). In many sedimentary basins and reservoirs, Breckels and Eekelen (1982), Engelder and Fischer (1994), Addis, 1997, Hillis (2003) or (Tingay et al., 2003, 2009) described a relationship between the fluid pressure and the minimum horizontal stress S_h in which S_h reduces with pore pressure depletion and higher S_h values are observed in overpressured sequences. Such coupling between pore fluid pressure and stress tensor was also underlined by Mourgues and Cobbold (2003). These authors verified experimentally that fluid overpressure gradients induce an additional component (seepage force) to the effective stresses equilibrium and they verified that listric normal faults could form in response to the stress rotation induced by non-vertical gradients of pore fluid overpressures (Mandl and Crans, 1981). Lateral pore pressure gradients due to pore pressure field around an overpressured reservoir may also modify the total stresses. Recently, Rozhko et al. (2007) found some analytical solutions to predict the fracture pressure induced by a localized increase of pore pressure diffusing in a homogeneous medium. In highly overpressured covers (low effective stress), where pore pressure is close to S_3, pore fluid overpressure gradient may become one of the main body forces (Mourgues and Cobbold, 2003) resulting in a strong couple between fluid pressure and S_3. In this paper, we explore the various relationships existing between pore fluid pressure and horizontal stress S_h in overpressured sealing formations. Using elastic rheologies, we show that S_h/P_p coupling depends on the distribution of fluid overpressures in the basin. Then, we compare analytical results derived for a localized source of pressure encased in overpressured sediments with data obtained from hydraulic fracturing experiments involving analogue materials and fluids. Finally, we discuss the applicability of our model to failure pressure predictions and to evaluation of retention capacity.

2. Effect of pore pressure distribution on S_h/P_p coupling

One key point for understanding the coupling between pore pressure and stresses at basin scale is to know the origin of stresses at depth. The total vertical stress is commonly supposed to be equal to the overburden weight and may be written as:

$$S_v = \int \rho_b(z) g dz \tag{2}$$

with ρ_b the bulk density of the sediments. According to Anderson's theory, this vertical stress is one of the main stresses. The two other main stresses are also supposed to be horizontal (Anderson, 1951). Nevertheless, in sedimentary basins, it is more difficult to estimate these horizontal stresses because they are partly due to the weight of the sediments and to additional tectonic stresses and because they depend on the sediment rheology as well. Other stresses can also locally superimpose next to faults for example. At basin scale, for analysis and modelling, it is common to use empirical relationships to link horizontal stress to depth. Breckels and Eekelen (1982) derived relationships between horizontal stress, depth and fluid overpressure in the Gulf Coast. Others assume that the total horizontal stress can be deduced from the total vertical stress by the following formula (Schneider et al., 1999, 1997)

$$S_h = K S_v \tag{3}$$

Because it is expressed in total stresses, such a relationship is conveniently independent of the knowledge of the sediment rheology. Factor K may be a function of depth and may vary according to the tectonical environment. Grauls (1997, 1999) defined different expressions for various tectonic regimes: type I (offshore passive margins, deltas, normal faulted contexts), type II (offshore strike slip faulted contexts), type III (thrust faulted, fully compressive contexts). For example, from values given by Grauls (1997), Schneider et al. (1999) derived expression of K for passive margins.

$$K(z) = 0.85 - 0.18\exp(-z/2650) \tag{4}$$

Because K only depends on z, expression 4 is only valid for hydrostatic pore pressure conditions. To introduce a pore