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Quantitative evaluation of fault lateral sealing

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Abstract: - Fault sealing mechanism mainly has two types including capillary seal and hydraulic seal. Capillary seal is the most common type, relying on the capillary pressure difference between fault and reservoir. Fault lateral seal types are divided into juxtaposition seal, fault rock seal and cementation seal according to the internal characteristics of fault zone. Fault rocks seal are classified into three categories depending on the content of shale or phyllosilicates of the faulted horizons, including cataclastic rock seal when it is less than 15%, phylloslicate-frame rock seal when it is between 15 to 40% and clay smear seal when it is greater than 40%. However, different seal types have different evaluation methods. Allan diagram and Knipe diagram provide methods to assess juxtaposition seal. But we use SGR algorithm to calculate the fault zone shale content to quantitatively evaluate fault rocks seal. Across fault pressure difference is increasing with increasing SGR, and the fault forms effectively seal, when the SGR reaches a certain number.
Keywords: - *AFPD, fault lateral sealing, fault rock seal, juxtaposition seal, SGR algorithm.*

I. INTRODUCTION

We can conclude that fault sealing mechanism mainly has two types including capillary seal and hydraulic seal from research results of sealing mechanism. And the most common type is capillary seal. Early in 1949, Purcell carried out detailed experimental and deduced about capillary pressure calculations (Fig.1), and acquired a clear relationship among capillary pressure, pore radius, wetting angle and interfacial tension[1]. Hubbert believed that the fundamental cause of hydrocarbon accumulations is the capillary pressure difference between reservoirs and wall rock, so it relies on the capillary pressure difference between fault and reservoir whether the fault can have the ability to seal the fluid or not[2]. The capillary pressure difference can support the hydrocarbon column height of traps. Since the fault is not a two-dimensional surface, and has the length and breadth of the three-dimensional geological body, we must consider the internal structure of the fault zone to evaluate the sealing ability of the fault. Material composition and content of the fault zone determine the capillary pressure difference between fault and reservoir. Because the different internal characteristics of fault zone develop different types of lateral seal, the evaluation methods are various.

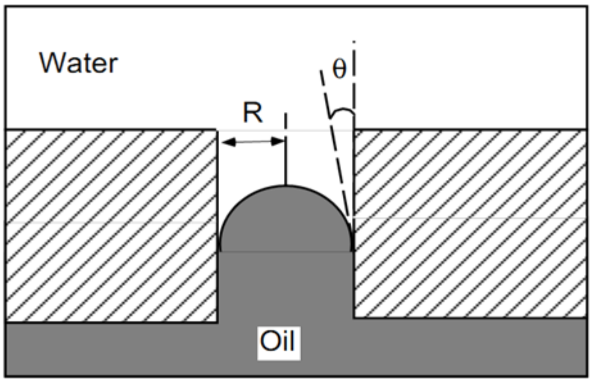

Fig.1: The mechanism of capillary seal.

II. THE TYPES OF FAULT SEALING

It is correlative with reservoir thickness, the thickness of the cap rock and throw whether the fault forms effective seal macroscopically or not. At the same time, fluid may be altered because of subsequent faulting activation. According to many research results, the type of fault seal is divided into three categories: juxtaposition seal, fault rock seal and cementation seal. Many scholars believed that the type and physical property of fault rock depended on the shale content of in situ rock, so fault rock types were carefully divided: cataclastic rock seal, phylloslicate-frame rock seal and clay smear seal.

2.1 Juxtaposition seal

Allan used juxtaposition seal model in the study of hydrocarbon migration patterns for the first time in 1989[3]. Model principle: when the reservoir from the top is juxtaposed with the closure layer, the fault is lateral sealing for oil and gas; when the reservoir is juxtaposed with reservoir, the fault is lateral leak as effective migration pathway for oil and gas. Its sealing ability is determined by the thickness of the closure layer which is juxtaposed with the reservoir, the throw of the fault and the capillary pressure difference between the closure layer and reservoir. In theory, the more the thickness of the sealing layer is, more easily the fault forms sealing.

2.2 Fault rock seal

Cataclastic rock seal is developed when the content of shale or phyllosilicates of the faulted horizons is less than 15%, and belong to the result of pure sandstone fault deformation.

Phylloslicate-frame rock seal is formed in condition that the content of shale or phyllosilicates of the faulted horizons is between 15 to 40%, and is the product of fault deformation in impure or rich argillaceous sandstones. Due to the mixing between the compaction accompanying with faulting and shale or phyllosilicates, the fault zone has relatively low porosity and permeability.

Clay smear seal is developed when the content of shale or phyllosilicates of the faulted horizons is more than 40%. It is continuous and smears along the fault plane. Since the sealing ability of clay smear is similar to the closure layer, the porosity and permeability of the fault zone is relatively low.

2.3 Cementation seal

Fault will produce tensile fractures with different sizes in deformation process. The fractures can act as pathways for fluid migration and may provide the space and environment for the deposition of minerals. If these tensile fractures are filled with low permeability minerals and are cemented before accumulation period, such as iron-bearing minerals, siliceous minerals, calcareous minerals and asphalt, the porosity and permeability of the fault will be greatly reduced. Then cementation seal is formed.

III. QUANTITATIVE EVALUATION METHOD OF FAULT LATERAL SEAL

3.1 Allan diagram and Knipe diagram

When the throw is less than the thickness of the shale, the upthrown block will be juxtaposed with the shale for juxtaposition seal. Allan established juxtaposition seal model, and developed lithology juxtaposition diagram of the fault plane about the thickness of sides of fault, the pattern of the horizon, lithology and throw. The lithology juxtaposition diagram is called Allan diagram (Fig.2), and directly reflects the status of juxtaposition at any point in the plane.

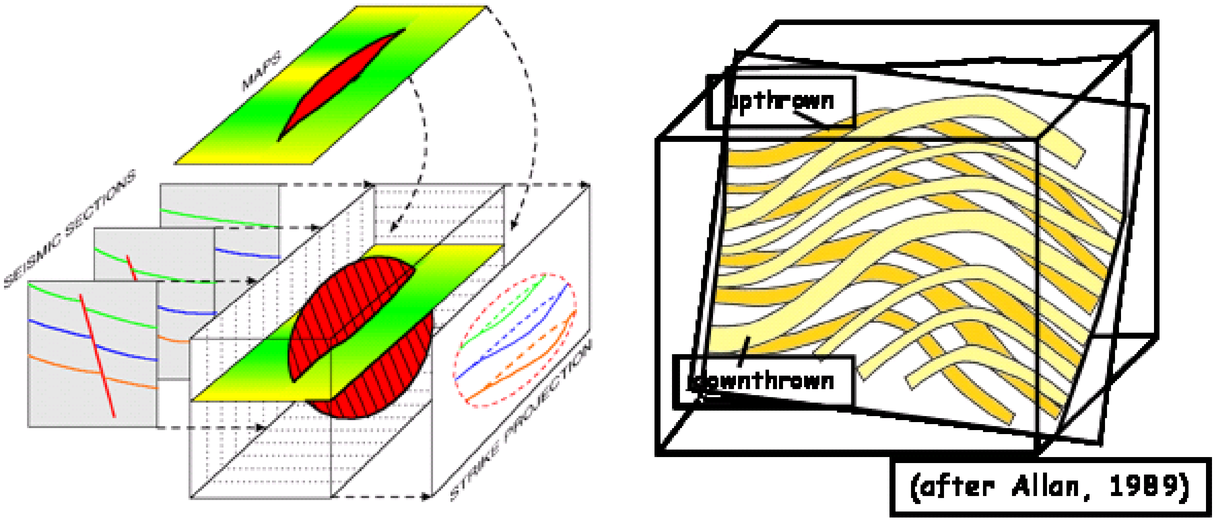

Fig.2: Allan diagram. The Allan diagram directly reflects the status of juxtaposition at any point in the plane.

Knipe [4] utilized the way of triangular diagram to express lithology juxtaposition. And it is called Knipe diagram (Fig.3). The Knipe diagram can describe the relationship between the horizon and its opposite at a certain throw by the way of coordinate. It is simpler to draw than Allan diagram.

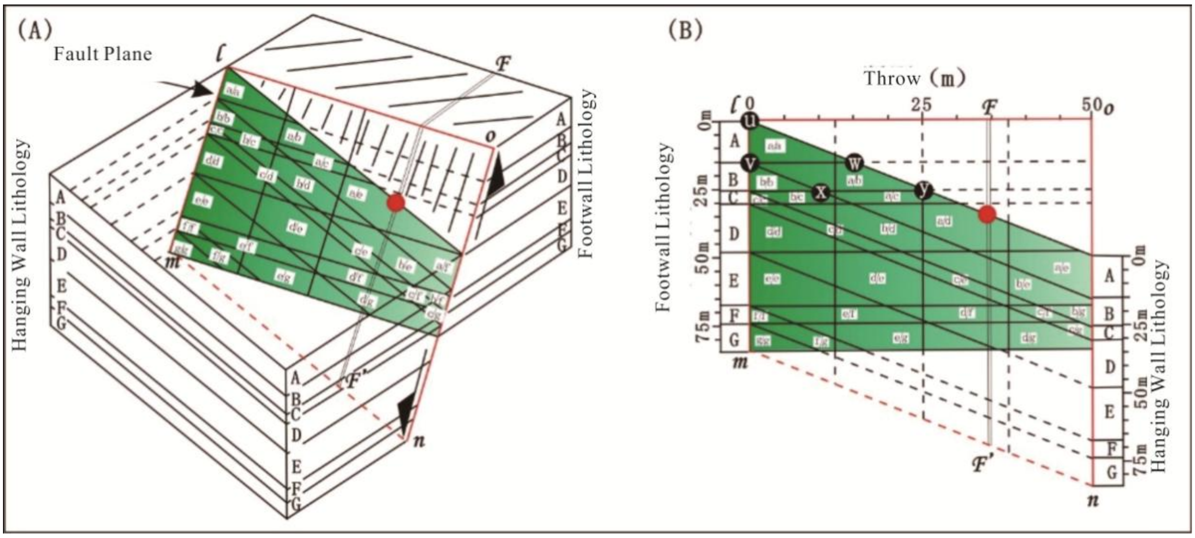

Fig.3: Basis of the juxtaposition diagram. The Knipe diagram can describe the relationship between the horizon and its opposite at a certain throw by the way of coordinate.

The above two methods are very useful in the initial stage of sealing evaluation, but are not widely used for the fine interpretation of sealing, because both are based on the assumption of two-dimensional fault, and do not involve the effect of internal structure and fault rock for sealing. When a reservoir is juxtaposed with another reservoir, the methods of diagram cannot be accurately evaluated for fault lateral sealing, and we introduce fault rock sealing for this situation.

3.2 SGR algorithm

Since the fault is not a two-dimensional surface, and has the length and breadth of the three-dimensional geological body, we must consider the internal structure of the fault zone to evaluate the sealing ability of the fault. Material composition and content of the fault zone determine the capillary pressure difference between fault and reservoir. Yielding[5] and Fristad[6] proposed shale gouge ratio algorithm to calculate the clay content of the fault zone. The SGR is simply the percentage of shale or clay in the slipped interval. The SGR represents, in a general way, the proportion of shale or clay that might be entrained in the fault zone by a variety of mechanisms. The more shaly the wall rocks, the greater the proportion of shale in the fault zone, and therefore the higher the capillary entry pressure. Figure 4 illustrates how this would be calculated, at a given point on a fault surface, for explicit shale beds:

$$SGR = \frac{\sum (zone\text{-}thickness) \times (zone\text{-}clay\text{-}fraction)}{throw} \times 100\% \tag{1}$$

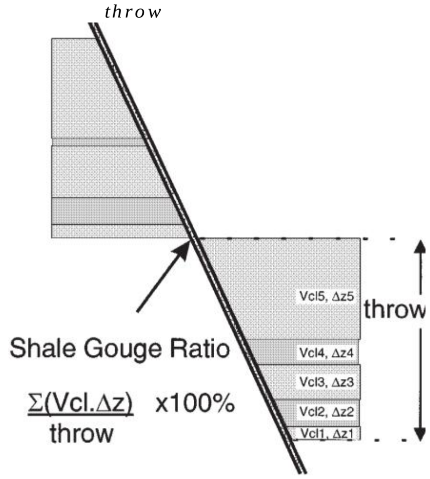

Fig.4: Gouge ratio algorithms for estimating likelihood of clay entrainment in the fault gouge zone.

Fault sealing ability under hydrostatic conditions depends on the capillary pressure difference between fault and reservoir. Gibson confirmed that the fine argillaceous material can effectively reduce the porosity of fault rock and increase the capillary pressure of the fault zone in 1994, so more the shale content is, stronger the fault sealing ability is. Therefore, accurate prediction of fault shale content and the relationship between clay content and across fault pressure difference are critical to assess fault sealing ability.

If the fault is closed, there is a pressure differential called across fault pressure difference (AFPD) between the two fault blocks (Fig.5). AFPD can be determined by pressure-depth relationship in both sides of fault or the depth of oil water contact. Then we calculate the shale content of fault plane with SGR algorithm to determine the relationship (Fig.6) between AFPD and SGR and get the fault seal failure envelope:

$$AFPD = 10^{\left(\frac{SGR}{d} - C\right)} \qquad (2)$$

Where C is a depth-dependent constant, when the depth is less than 3000m, C = 0.5; when the depth is between 3000 ~ 3500m, C = 0.25; when the depth is more than 3500km, C = 0.

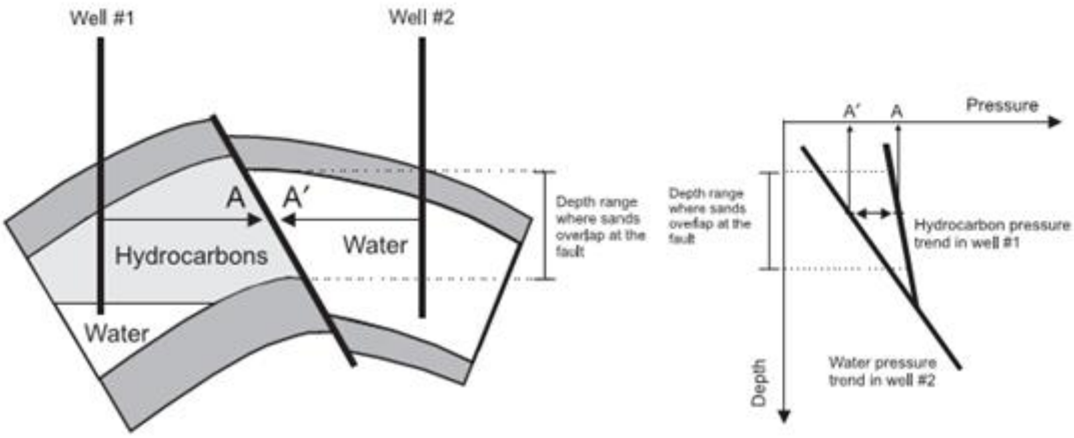

Fig.5: Across-fault pressure difference, or AFPD, is the difference in pressure between hydrocarbons in the upthrown side (A) and water in the downthrown side (A') measured at the same depth on the fault surface. Where there is a common aquifer, the AFPD values represent buoyancy pressures. Pressure data at wells are extrapolated along horizontal pressure gradients (hydrostatic conditions) to the fault.

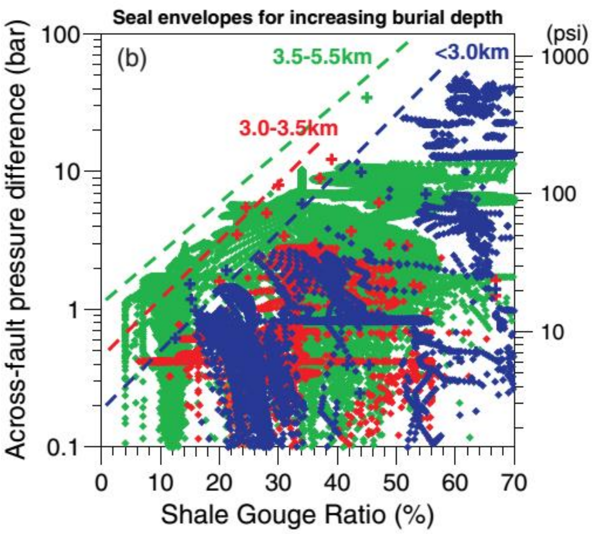

Fig.6: Comparison of Shale Gouge Ratio and in situ across-fault pressure difference for faults in a variety of extensional basins.

AFPD supports the hydrocarbon column height, the relationship between AFPD and the hydrocarbon column height is below. H is the hydrocarbon column height:

$$H = \frac{AFPD}{(\rho_w - \rho_o)g} \qquad (3)$$

Where H is the hydrocarbon column height, m; ρ_w is the density of water, kg/m^3; ρ_o is the density of hydrocarbon, kg/m^3; g is the gravitational acceleration, m/s^2.

Finally, we can obtain the relationship between SGR and the hydrocarbon column height to assess other traps undrilled according to the above:

$$H = \frac{10^{\left(\frac{SGR}{d} - C\right)}}{(\rho_w - \rho_o)g} \tag{4}$$

Where H is the hydrocarbon column height, m; ρ_w is the density of water, kg/m^3; ρ_o is the density of hydrocarbon, kg/m^3; g is the gravitational acceleration, m/s^2; d is a coefficient.

Yielding applied the SGR algorithm to Nun River oil fields in Niger Delta. When SGR is less than 20%, there is not sealing fault-block hydrocarbon reservoir. When SGR is more than 20%, fault has the effective sealing ability[5]. Weber considered that fault has the effective sealing ability, when the shale content is 25~30%[7]. Childs also concluded that the sealing ability of fault increased significantly when SGR is about 20%[8].

IV. CONCLUSION

Material composition and content of the fault zone determine the capillary pressure difference between fault and reservoir. The across fault pressure difference increases with shale content, and the more shale content is, the stronger the sealing ability is. According to previous studies, When SGR is about 20%, fault has the effective sealing ability, and the sealing ability increases with the increase of SGR.

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