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Identification of Downhole Fluid Properties Using Wireline Formation Test Data

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Abstract

In the process of offshore exploration, wireline formation sampling technology is an important means to identify the properties of reservoir fluid. However, due to the invasion of drilling fluid, reservoir permeability, pumping efficiency and other factors, the cable formation test operation often cannot obtain relatively pure undisturbed formation fluid samples, resulting in the difficulty of judging the properties of reservoir fluid. In this paper, three methods are compared and analyzed. One is the pressure gradient method based on the difference of oil and water density to distinguish fluid properties; Secondly, formate is used as the characteristic ion to calculate the purity of the sample and judge the fluid properties of the sample; Third, the fluid acoustic time difference parameter can directly reflect the properties of the current pumped fluid. The formation pressure analysis data can effectively identify the fluid properties of the reservoir and divide the oil-water interface, which improves the efficiency of exploration and development. Formate is used as a characteristic ion to calculate the purity of cable formation test samples, which expands the original calculation method and is compared with the traditional method. The effect is good and increases the reliability of on-site water analysis technology. The acoustic time difference method changes the idea of conventional sampling, making the sampling operation more purposeful and efficient.

Subject Areas

Petrochemistry

Keywords

Cable Formation Test, Pressure Gradient Method, Sample Purity, Fluid Acoustic Moveout, Fluid Properties

1. Introduction

The identification of reservoir fluid properties is an important work in oil and gas exploration and development. For a long time, resistivity absolute value method, resistivity porosity intersection method, porosity saturation intersection method and other methods with resistivity logging as the core have played an important role in the identification of conventional reservoir fluid properties. With more and more "three low" oil and gas reservoirs represented by "low resistivity, low porosity and low permeability" in offshore exploration, it is increasingly difficult to identify and evaluate reservoir fluid properties. In the stage of offshore exploration, cable formation test sampling technology has become an important means to solve this problem. However, in the application process, due to the influence of drilling fluid invasion, reservoir permeability, pumping efficiency and other factors, the cable formation testing operation often fails to obtain relatively pure undisturbed formation fluid samples. If you want to get a relatively pure formation sample, you must use a longer pumping time to eliminate the impact of mud filtrate intrusion in the formation. This not only costs a lot of exploration, but also brings greater operational risk due to long operation time. Therefore, in the process of sampling by wireline formation pump, it is impossible to effectively identify the nature of the fluid pumped, which may lead to misjudgment of the reservoir fluid property. Accurate identification of pumped fluid properties can provide an important basis for on-site operation decision-making [1] [2].

It can be seen from literature research that the research on fluid property identification is mainly focused on logging technology. In view of the geological characteristics and logging response characteristics of Kenli 10-1 structure, Zhang Zhihu qualitatively identified the reservoir fluid properties according to the shape and amplitude difference of the resistivity curve by using the overlap of 100% water bearing formation resistivity curve and the formation measured resistivity curve, and achieved good application results. Hao Peng applied the reservoir quantitative fluorescence technology to the identification of reservoir fluid properties in Shahejie Formation of BZ-A structure in Huanghekou Sag, Bohai Sea, and the identification results are consistent with the logging interpretation and oil testing results. Zhang Guodong used the high invasion characteristics of oil-based drilling fluid and based on the concept of time shift logging, proposed a method to quickly identify fluid properties by comparing the difference between real-time resistivity and re-measured resistivity [3].

This paper will introduce three methods to distinguish fluid properties by cable formation testing. Calculating the pressure gradient from the test data is one of the main functions of the wireline formation tester. The pressure gradient can be used to analyze the properties of formation fluids and determine the oil-water interface. The application and development of on-site rapid water analysis technology can improve the reliability of sample purity analysis and fluid property judgment. Fluid acoustic moveout parameters can directly reflect the properties of the current pumped fluid, and can quantitatively judge the fluid salinity through real-time calculation, with high accuracy [4].

2. Pressure Gradient Method

Using the obtained formation pressure, the pressure depth profile can be established to judge the reservoir connectivity, calculate the formation pressure gradient and fluid density, determine the oil-water interface and distinguish the fluid properties [5].

2.1. Principle of Distinguishing Fluid Properties

Different densities of oil and water show the difference of pressure gradient in the reservoir pressure system, which is the physical basis for the pressure gradient method to distinguish fluid properties. The formation pressure measured by wireline formation tester can be used to establish the pressure depth profile. The depth here is the vertical depth of the formation after bushing and well deviation correction [6] [7] [8]. For the fluid with the same property in the same pressure system, theoretically, the formation pressure measured at different depth points presents a linear relationship.

$$p_1 - p_2 = G_h \left(D_{v1} - D_{v2} \right) \tag{1}$$

where, p_1 and p_2 are the formation pressures of the same fluid with different effective pressure measuring points in the same pressure system, psi (1 psi = 6.895 kPa), Unit of cable formation tester; G_h is the pressure gradient, representing the change of hydrostatic column pressure per unit vertical depth, psi/m; D_{V1} and D_{V2} are the true vertical depth of the stratum corresponding to the pressure measuring point, m. If there are fluids with different properties in the same pressure system and the density is obviously different, the pressure values at each depth point are not in a straight line. The inflection point of the pressure line represents the depth of the fluid interface.

Hydrostatic pressure is:

$$P = \rho g D \tag{2}$$

Simultaneous (1) and (2), and conversion of units:

$$\rho = \frac{p}{D}\frac{1}{g} = \frac{G_h \times 6.895}{g} = \frac{G_h}{1.421} \tag{3}$$

where, p is the hydrostatic pressure, kPa; ρ is fluid density, g/cm^3; g is the acceleration of gravity, 9.8 m/s^2; D is the liquid column height, m. To calculate the pressure gradient from test data, it is first necessary to establish the formation pressure depth (depth profile after bushing height correction and inclined shaft alignment). If the pressure is overpressure or there may be overpressure, it can only be used for reference rather than blind application. The pressure depth profile is made with the pressure as the abscissa and the depth as the ordinate. In the pressure depth profile, for the same pressure system with the same fluid property, the connection of formation pressure measured at different depth points is theoretically linear, and the slope of the connection is the pressure gradient of the pressure system. Therefore, based on the calculated pressure gradient, the fluid density can be calculated and the formation fluid properties can be identified (Table 1).

2.2. Application Case Analysis

The pressure data of 15 pressure measuring points were obtained in Well X. The test pressure is divided into three sections from bottom to top to calculate the pressure gradient respectively, and then the fluid density is obtained. The results are 0.188, 0.211 and 1.184 g/cm^3. According to the characteristics of logging curve, it is judged that the first layer is a tight gas layer, the second layer is a conventional gas layer, and the third layer is a water layer. The pressure gradient line intersects at 4222.5 m, which is judged as the position of gas water interface (Figure 1).

3. Rapid Water Analysis Technology

This technology uses the ion chromatography analyzer to quickly analyze and obtain the common ion concentrations in the sample. By comparing with the ion concentrations in the mud filtrate and using traditional water analysis and calculation methods, the volume ratio of mud filtrate to formation water in the

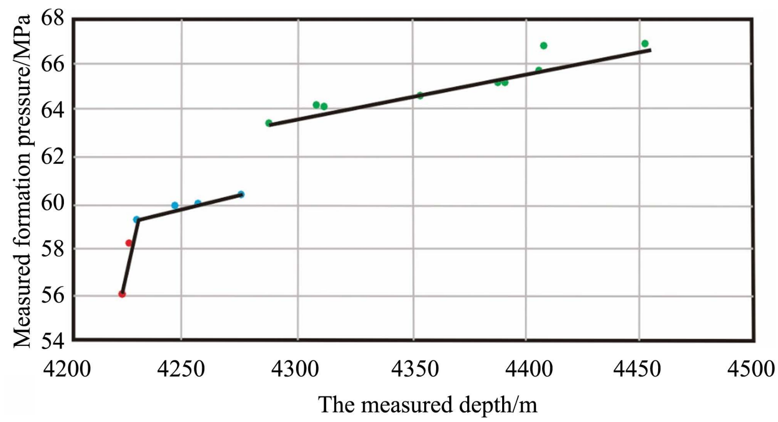

Figure 1. Formation static pressure gradient of Well X.

Table 1. Typical density and pressure gradient of natural gas, oil and water.

Serial number	Fluid type	Density (g/cm^{-3})	Pressure gradient (psi/m^{-1})
1	Natural gas	0.18	0.25
		0.25	0.35
2	Oil	0.80	1.12
		0.85	1.19
3	Fresh water	1.00	1.42
4	Salt water	1.07	1.50

water sample can be calculated, and the total salinity and resistivity of formation water can be estimated [9] [10].

3.1. Traditional K^+ Concentration Method

The offshore drilling mud system is generally potassium chloride mud system. The K^+ concentration is very high, but the K^+ content in the formation is relatively small, and K^+ is not easy to react with other ions. Therefore, in practical application, taking K^+ as the characteristic ion to distinguish formation water and mud filtrate, the method to calculate the proportion of formation water and mud filtrate in water sample is the quantitative K^+ concentration method. The calculation formula is:

$$M = \frac{R_1 - R_2}{R_1 - R_0} \tag{4}$$

where, M is the content of formation water in the water sample, 100%; R_0 is the K^+ concentration in regional formation water, mg/L; R_1 is the concentration of K^+ in mud filtrate, mg/L; R_2 is the concentration of K^+ in the water sample, mg/L. The regional empirical value of K^+ concentration R_0 in regional formation water is generally small, which has little impact on the calculation results.

The K^+ concentration method has a wide scope of application, and can be used for almost all offshore wells. However, if the shale content in the sampling interval is large, diffusion adsorption and cation exchange between K^+ and the formation will cause calculation errors.

3.2. $HCOO^-$ Concentration Method

Formate drilling fluid is a new type of drilling fluid system developed and applied in recent years. It has the advantages of wide salt density range, low crystallization temperature and corrosion potential, strong inhibition to shale, high solid pollution tolerance, no damage to production layer, non-toxic, etc. For offshore exploration wells, especially high-temperature and high-pressure wells, horizontal wells and other complex drilling conditions, formate system drilling fluid is often used.

$HCOO^-$ concentration in drilling fluid of formate system is very high, while there is almost no $HCOO^-$ in formation, so $HCOO^-$ can be used as a characteristic ion for quantitative calculation of samples. This paper proposes to use ion chromatography to determine the $HCOO^-$ concentration in mud filtrate and cable formation test sampling water sample, and calculate the content of formation water in the sample. The calculation formula is:

$$M = 1 - R_2/R_1 \tag{5}$$

where, R_1 is $HCOO^-$ concentration in mud filtrate, mg/L; R_2 is the concentration of $HCOO^-$ in water sample, mg/L.

$HCOO^-$ concentration method eliminates the selection of formation background value and makes the calculation method simpler. Under the chemical environment involved in drilling mud, $HCOO^-$ has good chemical stability, ensuring the accuracy of calculation. With the increasing application of offshore formate drilling fluid system, $HCOO^-$ concentration method will also be widely used.

3.3. Case Analysis

The pumping time of a certain exploratory well was 320 min, and the volume of pumped fluid was 148.7 L. At this time, pumping was stopped and sampling was conducted. The sample volume was 395 mL, and no oil and gas fluid was taken. The on-site water analysis results of the obtained water samples are shown in Table 2. It can be seen from the table that 25% of the samples are mixed with mud filtrate, and the sample purity is 75%, so it is determined that the reservoir fluid property is water layer.

4. Fluid Acoustic Transit Time Method

For the sampling operation, the types of fluids pumped are oil, gas and water (drilling fluid filtrate or formation water), and the acoustic transit time of different types of fluids is obviously different [11].

4.1. Instrument Principle

On both sides of the pipeline of the fluid analysis module of the cable formation testing reservoir characterization instrument, acoustic transmitters and receivers are installed respectively. The acoustic transit time of the fluid in the pipeline is calculated by measuring the time taken for the acoustic wave to penetrate the fluid in the pipeline. During the pumping of the instrument, the first wave of the acoustic wave is received through the calibration, and the acoustic moveout of the fluid is calculated accurately. It is very important to calibrate the first wave, otherwise the acoustic moveout of the fluid cannot be calculated accurately. With the continuous pumping, the time difference of fluid is measured in real time to obtain a curve of fluid acoustic time difference value changing with time, and the fluid property change is judged by the curve change and value [12].

During the sampling process, the properties of oil, gas and water are different, resulting in different acoustic propagation speeds, that is, different acoustic moveouts. Through the practical application statistics of several wells, it is found that the acoustic time difference of oil is generally 200 - 360 μs/ft, and that of water is generally 170 - 190 μs/ft (Figure 2). There is a very clear limit. The acoustic time difference during sampling can also be used as a basis for judging fluid properties.

Table 2. Field water analysis.

Sample name	Mud filtrate	The sample
$HCOO^-/(mg \cdot L^{-1})$	43,122	10,890
$HCOO^-$ concentration method was used to calculate the sample purity/%		75

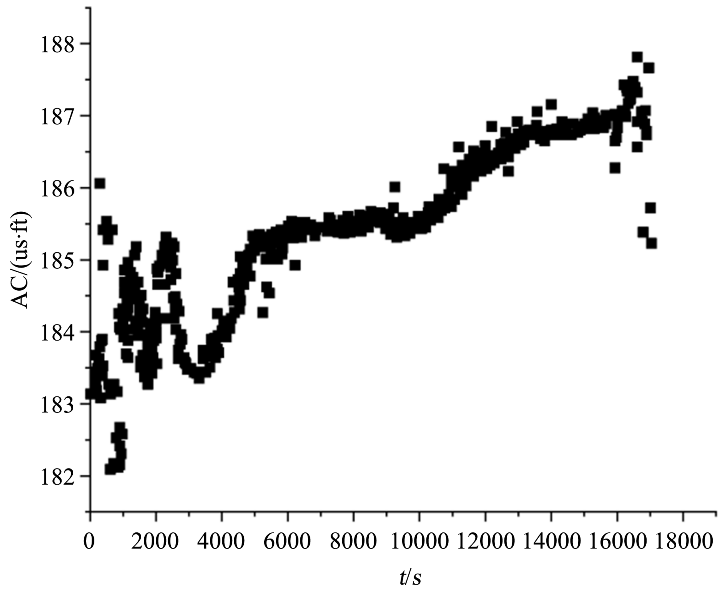

Figure 2. Fluid acoustic time difference curve.

4.2. Parameter Calculation Method

Laboratory data confirm that the acoustic transit time difference of water is mainly affected by temperature, pressure and salinity, while other factors have little impact. In the process of sampling, the temperature is basically stable when the instrument seat is pumped; when the pumping speed is stable, the fluid pressure in the pipeline is basically stable; the only change is the salinity of the pumped fluid, so the only factor affecting the acoustic transit time is the salinity of the fluid. Therefore, it is feasible to judge the fluid property or water salinity through the acoustic transit time of the fluid.

In the 1970s, according to the acoustic data of purified water, foreign scholars calculated the relationship between the acoustic velocity of purified water and temperature and pressure within 100˚C and 100 MPa:

$$v_w = \sum_{i=0}^{4}\sum_{j=0}^{3} W_{ij} T^i p^j \tag{6}$$

where, v_w is the acoustic velocity of purified water; T is the temperature; P is the pressure; W_{ij} is a constant coefficient.

Later, scholars modified the temperature and pressure conditions of Equation (1) and introduced the factor of salinity to obtain the formula for calculating the acoustic velocity v_B of brine:

$$\begin{aligned} v_B = v_w + C\big(&1170 - 9.7T + 0.055T^2 - 8.5\times10^{-5}T^3 + 2.6p - 0.0029Tp \\ &- 0.0476p^2\big) + S^{1.5}\left(780 - 10p + 1016p^2\right) - 820S^2 \end{aligned} \tag{7}$$

where, C is the salinity of formation water; v_w is the acoustic velocity of purified water.

Through Formula (7), it is confirmed that temperature, pressure and salinity are the main factors affecting the acoustic transit time difference in the process of sampling and pumping, and salinity is the main factor. Then, when the temperature T, pressure p, fluid acoustic velocity v_B and v_w are known during the sampling process, the salinity of the current fluid can be calculated according to Equation (7) to determine whether the water is formation water or filtrate.

4.3. Application Case Analysis

Taking the actual test of a well as an example, when pumping to 160 min, the acoustic time difference is 181.4 μs/ft, estimate 36,491 mg/L of chloride according to the formula, and fill the spare sample; When pumping to 270 min, the acoustic transit time difference is 182.5 μs/f, the estimated chloride radical is 29,130 mg/L, and fill the standby sample; When pumping to 440 min, the acoustic transit time difference is 183.4 μs/ft, the current fluid chloride is estimated to be 23,578 mg/L. According to regional experience, judge the water content and sample filling of this reservoir, and end the sampling operation at this point.

5. Conclusions

1) The formation pressure data obtained by using the wireline formation tester can effectively identify the fluid properties of the reservoir, divide the oil-water interface, and improve the exploration and development benefits. Due to the influence of instruments, operators and formation conditions, the pressure data obtained by the cable formation tester must be analyzed for effectiveness. After eliminating the influence of factors such as packer sealing failure, detector blockage, pressurization and dry point test, effective pressure measuring points shall be selected to calculate the fluid density.

2) Formate is used as the characteristic ion to calculate the purity of cable formation test sample. Compared with the traditional method, the effect is good and the reliability of on-site water analysis technology is increased.

3) The key to the application of acoustic moveout method is to calibrate the acoustic head wave to ensure the accuracy of acoustic moveout; accurately read the acoustic time difference of filtrate at the beginning of pumping, and calculate the accurate acoustic time difference of target. This method changes the idea of conventional sampling, making the sampling operation more purposeful and efficient.

Conflicts of Interest

The authors declare no conflicts of interest.

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