Formation overpressure and shale oil enrichment in the shale system of Lucaogou Formation, Malang Sag, Santanghu Basin, NW China

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Abstract: According to observation of cores and thin sections, as well as analyses of fluid pressure features and geochemical indexes, the cause of fluid overpressure and the mechanism of shale oil enrichment in the Lucaogou Formation, Malang Sag, Santanghu Basin, were discussed. The results show that the shale oil of the Lucaogou Formation is generated in the low mature–premature stage of the source rocks and has the features of high density and high viscosity. The low-permeability and thick source rocks lead to high start-up resistance of fluid, which made it difficult for oil and gas to expel, so the retainment of oil and gas in source rocks is the major cause of formation overpressure. Excellent generation potential and well developed reservoir space are the basis for the oil retention; the pressure produced by hydrocarbon generation is not high enough to overcome the resistance of oil migration, which leads to the enrichment of shale oil. The enrichment degree of shale oil is controlled by hydrocarbon generation and storage capacity of lithofacies at various evolution stages.

Key words: shale oil; overpressure; enrichment mechanism; Malang Sag

Introduction

The exploration and development of unconventional hydrocarbon has put off the commercial oil and gas production decline in the whole world [1-4]. As a new hotspot in unconventional oil exploration, shale oil, different from the artificially extracted oil from shale, is the liquid hydrocarbon generated and occurred in underground shale layers, and can be brought to surface after fracturing. The study on shale oil mainly focuses on the characteristics of source rock, evaluation of resources potential, development technologies, and so on [1], and the mechanism of shale oil formation still awaits in-depth study. In fact, all muddy hydrocarbon source-rocks in “oil window” generally contain retained hydrocarbon, but only when the retained hydrocarbon enriches to a certain degree, will the shale oil have the exploration and development prospect.

The shale oil layers generally have abnormal high-pressure. At the end of 20th century, mudstone fractured-reservoirs were successively discovered in Permian Lucaogou Formation of the Niujianhu, Mazhong and Heidun structural belts in Malang Sag, Santanghu Basin. Vertically continuous, the thick hydrocarbon source-rock has abnormal high-pressure and good hydrocarbon shows in common, but due to sharp variation in lateral oiliness and complex oil-gas distribution pattern, the success rate of exploratory drilling has been low, making it hard to build up productivity [5]. Based on the theory of unconventional oil-gas exploration, and drawing on lessons from the successful experiences in exploration of shale oil and gas abroad, Well L50 drilled in the northeast of Mazhong structural belt in 2010 tapped a daily oil flow of three cubic meters after horizontally sidetracking and fracturing in the dolomitc mudstone intervals in Lucaogou Formation [6], which opened a new chapter in shale oil exploration in this area. Through analyzing liquid pressure characteristics and geochemical indicators in the source rocks, in conjunction with observation of cores and thin sections, this paper analyzes the origin of abnormal formation pressure and the enrichment mechanism of shale oil.

1 Overview of study area

Located on the south edge of Siberia Plate, adjacent to the plate section of Altai continental crust in the north and the...
Palaeozoic active continental margin of north Tianshan Mountain in Kazakhstan Plate in the south\(^7\), the Santanghu Basin belongs to the active belt of continental margin during the geological age. The basin is a strip trending north-west-south-east, about 500 km long, 40–70 km wide, covering an area of about 2.3×10\(^4\) km\(^2\) (Fig. 1).

Malang Sag is located in the southeast of the central depression belt in the Santanghu Basin, where the cap-rock reaches up to 6 500 m thick, and the strata are Tertiary, Lower Cretaceous, Jurassic, Middle-Up Triassic, Upper Permian and Carboniferous from top to bottom. Subjected to denudation during Indo-China movement in the northeast of the sag, residual Permian Lucaogou Formation nowadays is distributed in the southwest of Malang Sag. With a little original terrestrial input, Lucaogou Formation is mainly thin interbeds of carbonate rock and dark mudstone formed in the water-body environment of lower energy. As the major source rocks for medium-shallow reservoir systems in the basin, the mudstone has a carbonate mineral content of 2%–45%, high organic content, TOC value of 0–18% (mostly 1%–8%), the measured \(R_0\) between 0.5% and 0.9%, small part of samples over 0.9%.

Generally less than 8% in porosity and lower than 0.05×10\(^{-3}\) \(\mu\)m\(^2\) in permeability, the reservoir size and the oil drainage capacity of the well depend on the oil content in matrix of argillaceous shale in Permian Lucaogou Formation. The movable oil is mainly distributed between the lamina surfaces and in the fracture networks and the small amount of large pore-throats in matrix (Fig. 2a–c). On the argillaceous shale samples burnished by argon ion light beam, a large amount of tiny pores and fractures can be observed (Fig. 2d).

2 Abnormal formation pressure

2.1 Distribution characteristics of abnormal formation pressure

Due to quick subsidence of the basin and hydrocarbon generation\(^8\), the pressure coefficient of Lucaogou Formation is significantly higher than that of the overlying Jurassic. In the state of undercompaction, the source rock layers with abnormal high pressure have a higher porosity, which is represented by the deviation of all parameter values from normal range on well logging curves, for example, small density values, big interval transit time, and so on.

Considering comprehensive consideration of the changing rules of pore space during overpressure formation in the study area and using well logging data, the formation pressure of individual wells was predicted by equivalent depth method and compared with the actual pressure data from formation testing and corrected. Results indicate that the overpressure occurs within source rock in Permian Lucaogou Formation in Malang Sag, and is maximum in premium source rock in Member 2 of Lucaogou Formation, with the top of overpressure at about 1 500 m deep (Fig. 3).

2.2 Oil physical-property characteristics in abnormal formation pressure system

With the burial depth mostly at 1 400–2 300 m, oil-bearing source rocks in Lucaogou Formation in Malang Sag have a \(R_0\) value between mainly 0.5%–0.9%, almost all being at the stages of low-mature to early-mature. Analysis of crude oil biomarkers shows that the crude oil has not experienced biological degradation\(^9\), and the maturity parameters, such as \(C_{29} \text{gonane } \beta\beta/ (\beta\beta + \alpha\alpha)\), \(C_{29} \text{gonane } \alpha\alpha 20\text{S}/ (20\text{S} + 20\text{R})\), and so on, also indicate that the crude oil maturity is not high (Fig. 4).
The crude oil of Lucaogou Formation is high in density and viscosity. At 20 °C, the average crude oil density is 0.9003 g/cm³; at 50 °C, the average crude oil viscosity is 738.8 mPa·s (Fig. 5); the density and viscosity of crude oil decline gradually with the increase of burial depth and maturity. The Lucaogou Formation is thick, 300−800 m in the main exploration area. Controlled by the original sedimentary environment, terrigenous supply was insufficient, little sandstone developed. Thus, the high density and viscosity of the crude oil in source rock is not likely the result of hydrocarbon expulsion but rather its low maturity.

2.3 Origin analysis of anomalous formation pressure

The source rock in most area entered oil-generating window at the end of the Cretaceous, and the Rs value was 0.55%−0.75%. In this period, weakening dehydration of source rock didn’t produce enough water driving force to drive oil and gas migration. Kerogen was cracked into the
hydrocarbon of larger molecules, so the generated oil had a large density and high viscosity, high resistance of start-up migration. In addition, the big thickness and extremely low permeability of source rocks made the pressure gradient needed for oil and gas migration outside the source rock very high, hence a large amount of hydrocarbon generated in the source rock is retained in the areas and intervals with a large hydrocarbon-generating potential, causing the significant rise in pore pressure in the mudstone system and in turn the abnormal high pressure formation.

It can be seen from the measured pressure coefficient data (Fig. 6) that the overpressure top depth is 1 400–1 500 m, the burial depth of source rock at the stages of low-mature to early-mature was approximately 1 500–3 200 m, exactly during the stage of abnormal high pressure growth. The formation testing results in Wells L801, L7, L1, L5 and L6 show the overpressure Lucaogou Formation are all oil layers, the oil-water ratio increases with the rise of maturity and burial depth; in well fields L3, L31 and L702 where source rocks are poorer in quality and hydrocarbon generating potential, the Permian argillaceous shale systems have a formation pressure coefficient of about 1.0, no obvious abnormal formation pressure, and were proved to be aquifers by formation testing results.

The pressure variation trend of Lucaogou Formation in Malang Sag is consistent with the areal distribution regularity of source rock abundance and thickness. The layers have higher formation pressure, higher TOC value, and thicker source rocks, indicating that the high formation pressure abnormality is related to hydrocarbon generation (Fig. 7).
Moreover, the porosity starts to rise from the depth of 1 500 m to up to over 8%, showing that the abnormal overpressure has retained more pore space to some extent. Below 2 600 m, with decrease of hydrocarbon-generating amount of source rocks, the porosity also declines greatly; below 3 300 m, the lowest porosity can be down to below 5%, influencing the oil content. Buried at over 4 000 m deep in Well L9 (Fig. 6), the Permian does see overpressure, but was proved to be an aquifer by formation testing, which may be related to its very low porosity.

3 Shale oil enrichment mechanism

3.1 Large hydrocarbon-generating intensity

The types of organic matter, mainly type-I kerogen, in Lucaogou Formation, Malang Sag were controlled by sedimentary facies; after entering hydrocarbon generation threshold, type-I kerogen primarily produced oil. The matrix of Lucaogou Formation source rocks, rich in mineral asphaltene, is distinctive from source rocks in other basins, and rich sapropel amorphous hydrocarbon components are the main source of huge hydrocarbon generation in Lucaogou Formation. With TOC value mainly between 1% and 7%, and R0 value between 0.5% and 0.9%, the source rock is in oil-generating window, producing liquid oil mainly, similar to the source-rock conditions in Utica Marcellus area[10] (Fig. 8).

The main hydrocarbon-generating zone of source rock in Lucaogou Formation, Malang Sag is 1 800–2 900 m deep, with S1/(S1+S2) value reaching over 40%, the ratio of chloroform asphalt “A” and TOC value reaching over 20%. The hydrocarbon content in the formation is higher than that in the other layer systems, with the corresponding R0 value of 0.55%–0.75%.

At present, the shale oil is mainly discovered in the source-rock areas with high abundance and low-maturity to early-maturity; prematurity areas have poor hydrocarbon shows, when source rocks entered high mature stage (R0>0.8%), the shale oil abundance declined greatly because of the intense hydrocarbon expulsion. Therefore, controlled by source rock evolution, shale oil enriches in low-mature to early-mature source rocks.

3.2 Developed reservoir space in source rock

The lithology of Permian Lucaogou Formation in Malang Sag is mainly mudstone, calcareous mudstone and dolomitic mudstone. The physical properties of calcareous mudstone and dolomitic mudstone are better, with a porosity of 6%–12%, and a permeability of more than 10×10−3 μm2; mudstone has a porosity of 4%–10%, and a permeability of 1×10−3–10×10−3 μm2. There are mainly two genetic types of reservoir space. With the increase of source-rock maturity, the kerogen converts into liquid hydrocarbon gradually, causing the porosity in rocks to rise. The total organic carbon (TOC) is the mass fraction of organic matter, and the volume fraction of organic matter is about two times of the mass fraction. Study abroad confirms [11] that in the case that the average TOC value is 6.41%, if the density of organic matter is 1.18 g/cm3, the volume fraction of organic material is about 12.71%; the larger the TOC value of rock, the higher the volume fraction of rock occupied by the organic matter, the larger the rock porosity after entering the oil-generating widow and converting into hydrocarbon (Fig. 9). In addition,
the deposition of lacustrine fine-grained rock was influenced by weather greatly, the lithology of the formed source rock was impure, the high stiff grain content, such as quartz of 5% to 58%, the carbonate content of 2% to 45%, also contributed to the rich reservoir space in source rock.

3.3 Large primary migration resistance of crude oil

At present, a lot of studies have confirmed that the oil and gas in Lucaogou Formation is the hydrocarbon accumulation of self-generation and self-storage type [12]. Since the source rock in the study area is low-mature to early-mature, low in evolution degree on the whole, the viscosity of generated crude oil is high, leading to high startup pressure gradient for migration. When large pores are developed, the capillary pressure difference needed to be overcome is even bigger during hydrocarbon migration increase, as a result, the resistance to primary hydrocarbon migration rises. The abnormal high pressure brought about by the hydrocarbon generation might be the most important driving-force of primary hydrocarbon migration, but the maximum pressure coefficient of source rock layers does not exceed 1.4, not enough to overcome the hydrocarbon migration resistance. The source rocks are thick and wide spread, but the clastic reservoirs are not developed, lacking the channel conditions for large-scale primary-migration.

The combined effects of the above factors gave rise to the large resistance to primary hydrocarbon migration and insufficient driving-force, leaving a large amount of crude oil in large pores to form shale oil. What needs to be supplemented is that small-scale migration in source rocks might take place under this limited migration force and channel in source rocks.

On one hand, formation overpressure caused by hydrocarbon-generation could result in fractures created in shale along stress concentration surfaces, lithology contact transition surfaces or brittle and weak surfaces. On the other hand, in the source rock at the stages of low-maturity to early-maturity, gels converted from hydrogel to asphalt gel, formed a uniform asphalt phase and served as the “asphalt network” for continuous hydrocarbon migration [13]. They make it possible for the hydrocarbon liquid to conduct short-distance migration and small scope enrichment in source rock.

3.4 Controlling factors for shale oil enrichment degree

In the study area, insufficient supply of terrigenous clastics, and weak energy of water-body led to the formation of thick, wide spread and high carbonate content mud and shale. The semi-deep lake subfacies calcareous mudstone had better oil generation capability. There are diverse types of reservoir space, including rich matrix pores and the fractures along layers. Although high in organic-carbon content, the deep-lake subfacies mudstone is limited in reservoir space because of high clay and low carbonate content. Low in TOC contents, shore shallow-lake subfacies muddy dolomite and argillaceous limestone were insufficient in in-situ hydrocarbon generating potential, and the hydrocarbon generated in the deep sag could not migrate here restricted by geological conditions on a large scale, so the oil-cut of this facies belt is extremely low. In this set of argillaceous shale system, the calcareous-mudstone that enters the main oil-generating window is the most favorable facies belt for shale oil accumulation.

The formation testing results of the study area indicate that the water-cut of produced liquid from shallow and low mature argillaceous shale is high. When the burial depth of argillaceous shale was shallower, the water in reservoir space could not be drained off by compaction, so a small amount of hydrocarbon was generated, with poor oil water differentiation. With increase of burial depth, the amount of generated hydrocarbon increased, the water in reservoir space was further drained off by compaction, the wettability of rock converted into oil-wet, and the water in pores decreased. In summary, the shale oil enrichment degree is controlled by the hydrocarbon generating and hydrocarbon storing capacities of different rocks at different evolution stages (Fig. 10).

4 Conclusions

The shale oil in Lucaogou Formation was generated at low-mature to early-mature stage of source rocks, and the hydrocarbon could migrate outside on a large scale due to poor permeability of the source rocks, but was kept in situ. Retention of a large amount of crude oil in the source rock is the main reason of overpressure. The retained hydrocarbon would enrich to form shale oil with commercial value, when the following two conditions were met: (1) the source rock could generate and store a large amount of crude oil; (2) high liquid viscosity, continuous and thick source rock layers, and extremely low permeability made the resistance to primary hydrocarbon migration very high. The shale oil enrichment degree is controlled by the hydrocarbon-generating and hydrocarbon-storing capacities of different rocks at different evolution stages.
Fig. 10 Section schematic diagram of shale oil formation in Lucaogou Formation, Marang Sag

References


