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Prediction Method and Application of Hydrocarbon Fluid Migration through Faulted Cap Rocks

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Abstract: Hydrocarbon fluid migration through faulted cap rocks was determined by comparing the maximum connected thickness of cap rocks required for hydrocarbon fluid migration and the actual values, since cap rocks are important in the study of hydrocarbon fluid distribution in petroliferous basins based on its migration mechanism(s). The maximum connected thickness required was identified by comparing the cap rocks, fault displacement, and oil/gas distribution. The hydrocarbon fluid at the Putaohua reservoir migrated to the overlying Saertu and Heidimiao reservoirs in the Bayan Chagan Area, northern Songliao Basin. This was predicted to demonstrate the validity of the method. The results show that the adjusted Putaohua oil reservoir was distributed near the Talahai fault and Bayanchagan fault, rather than the Gulong sag in the southwest of the study area, where oil migrated vertically through the Sapu cap rocks to the overlying Saertu reservoir. Thick mudstone cap rocks in the second member of the Nenjiang Formation made it difficult for hydrocarbon fluid to migrate to the Heidimiao reservoir. This agrees well with hydrocarbon fluid distribution at the Putaohua, Saertu, and Heidimiao reservoirs in the Bayan Chagan Area, indicating that this method is feasible for predicting hydrocarbon fluid migration through faulted cap rocks.

Keywords: hydrocarbon fluid migration; faulted cap rocks; prediction method

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1. Introduction

Hydrocarbon fluid exploration practice reports that the hydrocarbon fluid that has accumulated or has been accumulating under mudstone cap rocks will be adjusted and will migrate to the overlying strata when faults destroy the overlying mudstone cap rocks. This will not only reduce hydrocarbon fluid accumulation numbers, but will also complicate the vertical hydrocarbon fluid distribution, which will bring difficulties to hydrocarbon fluid exploration activities [1–10]. Understanding this problem is critical for the hydrocarbon fluid exploration of faulted blocks in petroliferous basins. Previous studies have investigated hydrocarbon fluid migration from the underlying strata to the overlying strata. Besides the genetic relationships between reservoirs in vertical as well as reservoir development controllers [11–18], research mainly focuses on whether hydrocarbon fluid can migrate through faults [19–25], e.g., faults destroying the continuity of mudstone cap rocks [19–21] and fractures destroying the sealing ability of mudstone cap rocks [22–25]. However, these investigations are mainly performed at a certain point or in a certain hydrocarbon fluid reservoir, lacking prediction of the zone where underlying hydrocarbon fluid migrated to the overlying reservoirs, which is undoubtedly not conducive to the exploration activities at these kinds of reservoirs. Therefore, it is of great significance to establish a prediction method for hydrocarbon fluid migration through faulted cap rocks to guide hydrocarbon fluid exploration.

2. Materials and Methods

2.1. Migration Mechanism of Hydrocarbon Fluid Migration through Faulted Cap Rocks

Generally, the underlying hydrocarbon fluid will not migrate to the overlying strata due to prevailing mudstone cap rocks. However, the overlying cap rocks can be damaged by fault activities, and in this case, hydrocarbon fluid can migrate vertically through mudstone when the connected thickness (the difference between the mudstone thickness and fault displacement) is less than the maximum value required for upward hydrocarbon fluid migration, as shown in Figure 1A. If reservoirs are completely destroyed, no hydrocarbon fluid will be accumulated and distributed under cap rocks; otherwise, residual hydrocarbon fluid can be found. Whether the hydrocarbon reservoirs are adjusted or not mainly depends on fault activity strength; specifically, strong fault activity can develop associated and induced fractures, migrating hydrocarbon fluid significantly to the overlying strata. On the contrary, weak fault activity cannot develop fractures, only migrating part of the hydrocarbon fluid upward. However, if the connected thickness is greater than or equal to the maximum value required for hydrocarbon fluid's upward migration, the underlying hydrocarbon fluid will not be able to migrate through the mudstone cap rocks to the overlying strata (Figure 1B).

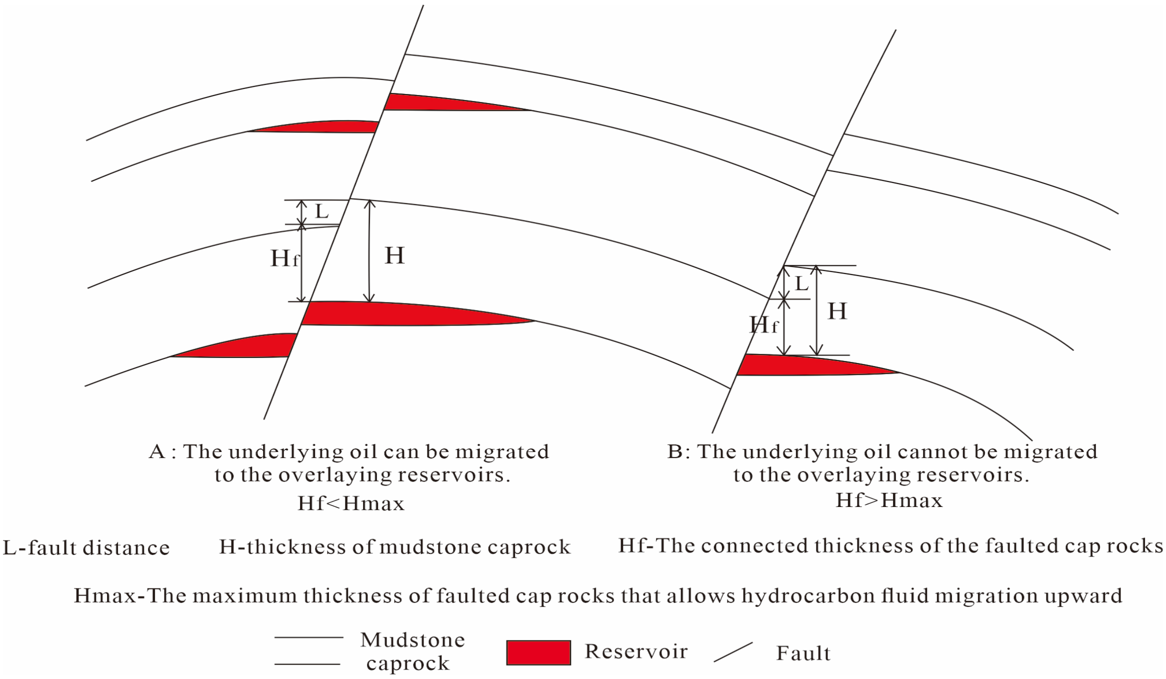

Figure 1. Diagram showing migration mechanism of hydrocarbon fluid migration through faulted cap rocks.

2.2. Prediction Method of Hydrocarbon Fluid Migration through Faulted Cap Rocks

The above analysis suggests that the actual connected thickness being less than the maximum value required is responsible for hydrocarbon fluid's upward migration. Therefore, it is necessary to determine the connected thickness at the mudstone cap rocks and the maximum connected thickness required. The connected thickness at the mudstone cap rocks can be determined by the cap rocks' thickness and the fault displacement acquired from drilling and seismic data. The required maximum connected thickness cannot be inferred theoretically and can only be determined via indirect methods under current research and technology. Specifically, the first is to obtain the mudstone thickness and fault throw at known well points, calculate connected thickness, arrange them in an increasing order, and then, identify the hydrocarbon fluid distribution above and below the corresponding mudstone cap rocks (Figure 2). The connected thickness at mudstone cap rocks (Hf9–Hf10 in Figure 2) where hydrocarbon fluid is distributed both at the upper and lower parts of the mudstone cap rocks is taken as the maximum connected thickness required for hydrocarbon fluid migration through the mudstone cap rocks. If the connected thickness is higher than the required maximum value, the underlying hydrocarbon fluid can only be accumulated and distributed under mudstone cap rocks, rather than migrating through them. On the contrary, the underlying hydrocarbon fluid can migrate through the mudstone cap rocks when the connected thickness is smaller than the required maximum value, where hydrocarbon fluid can be accumulated and distributed both under and above the mudstone cap rocks (Figure 2). Finally, all the calculated connected thicknesses should be marked on faults to map their plane distribution. After that, the area where the measured connected thickness is smaller than the required maximum value should be mapped to predict hydrocarbon fluid migration through the faulted cap rocks.

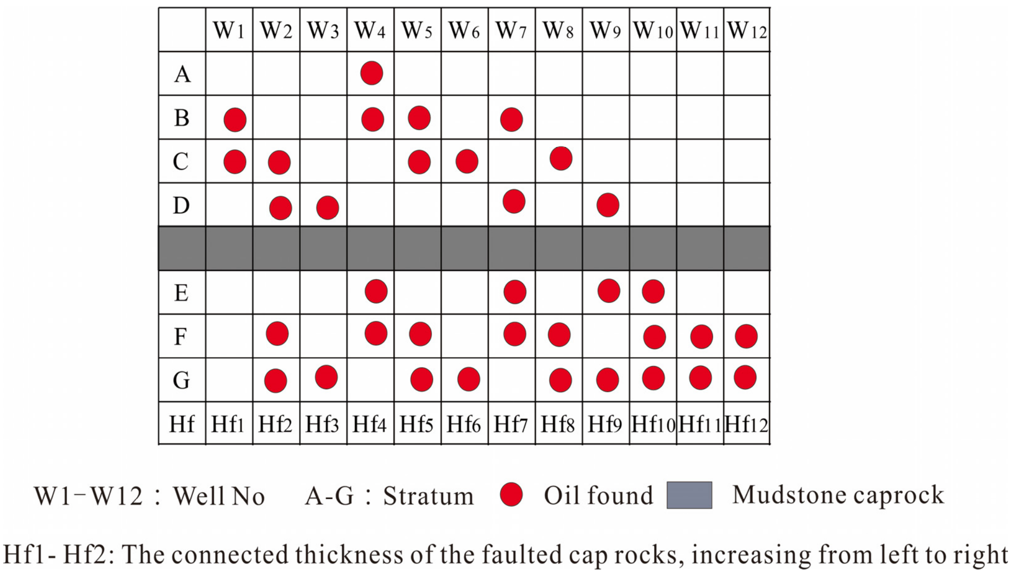

Figure 2. Diagram showing the maximum connected thickness required for hydrocarbon fluid migration through faulted cap rocks.

3. Example Application and Discussion

Previous studies have investigated hydrocarbon fluid migration from the underlying strata to the overlying strata. Besides the genetic relationships between reservoirs in vertical as well as reservoir development controllers [11–18], research mainly focuses on whether hydrocarbon fluid can migrate through faults [19–25], e.g., faults destroying the continuity of mudstone cap rocks [19–21] and fractures destroying the sealing ability of mudstone cap rocks [22–31]. However, these investigations are mainly performed at certain points or in a certain hydrocarbon fluid reservoir, lacking prediction of the zone where underlying hydrocarbon fluid migrated to the overlying reservoirs, which is undoubtedly not conducive to the exploration activities at these kinds of reservoirs. Therefore, it is of great significance to establish a prediction method for hydrocarbon fluid migration through faulted cap rocks to guide hydrocarbon fluid exploration.

Taking the Bayan Chagan Area in the north of the Songliao Basin as an example, this paper predicted positions where hydrocarbon fluid migrated from the Putaohua reservoir to the overlying Saertu and Heidimiao reservoirs using the proposed method. The application was verified by comparing the relationship between the prediction and the discovered hydrocarbon fluid at the Putaohua reservoir, the Saertu reservoir, and the Heidimiao reservoir at present.

The Songliao Basin in Northeast China is a Meso-Cenozoic continental petroliferous basin spanning the Heilongjiang, Jilin, and Liaoning provinces. It extends from NE to SW, with an area of about 260,000 km^2. It is about 750 km in the NS direction and is about 370 km in the EW direction. The Songliao Basin is mainly distributed at the Northeast Plain of China, bounded by the Songnen Plain in the north and the Liaohe Plain in the south. The basin is composed of six primary tectonic units, including the northeast uplift, the southeast uplift, the north plunging, the central sag, the southwest uplift, and the western slope zones. The Bayan Chagan Area in this study is located in the central sag, structurally including the northwest of the Gulong sag and the northeast of the Longhupao-Da'an terrace, with an area of about 280 km^2.

The investigated targets of this study are the medium-shallow buried Heidimiao reservoir (Nen-3 and Nen-4 member), the Saertu reservoir (Nen-1 member), and the Putaohua reservoir (Yaojia Formation). Thus far, the discovered hydrocarbon fluid has mainly been distributed at the Putaohua reservoir and the Saertu reservoir, with a small proportion at the Heidimiao reservoir. Oil-source correlation shows that hydrocarbon fluid in the study area was mainly derived from the underlying first member of the Qinghe Formation, which was a typical "new source to old reservoir". Whether hydrocarbon fluid generated by the first member of the Qinghe Formation could migrate through the Sapu mudstone and the Nenjiang mudstone to the overlying Saertu reservoir and the Heidimiao reservoir or not controls hydrocarbon fluid distribution in the Bayan Chagan Area. Therefore, accurately determining hydrocarbon fluid migration from the Putaohua reservoir to the overlying Saertu reservoir and Heidimiao reservoir is of great significance for guiding oil exploration in the Bayan Chagan Area (Figure 3).

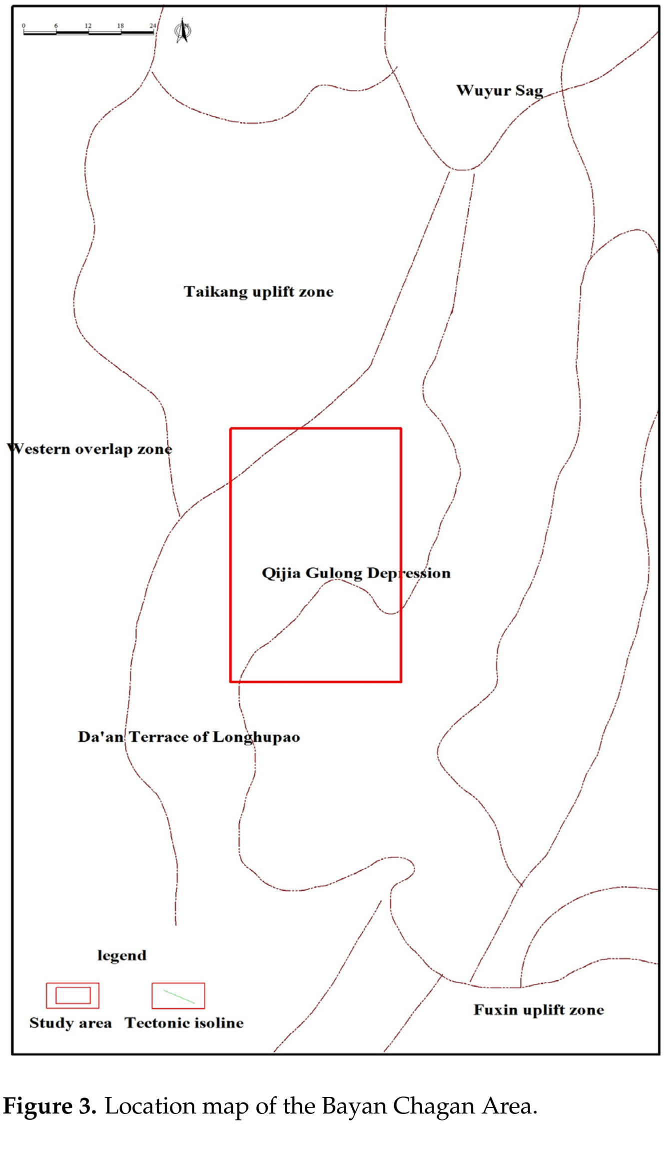

Figure 3. Location map of the Bayan Chagan Area.

Drilling and seismic data suggest that Sapu mudstone is developed at the top of the Putaohua reservoir in the Bayan Chagan Area. Figure 4 shows that the Sapu mudstone is widely distributed in the Bayan Chagan Area, with a maximum thickness >500 m at the southeast of the study area. It gradually decreases in the surrounding areas, with the minimum value (less than 10 m) in the central, western, and northern areas.

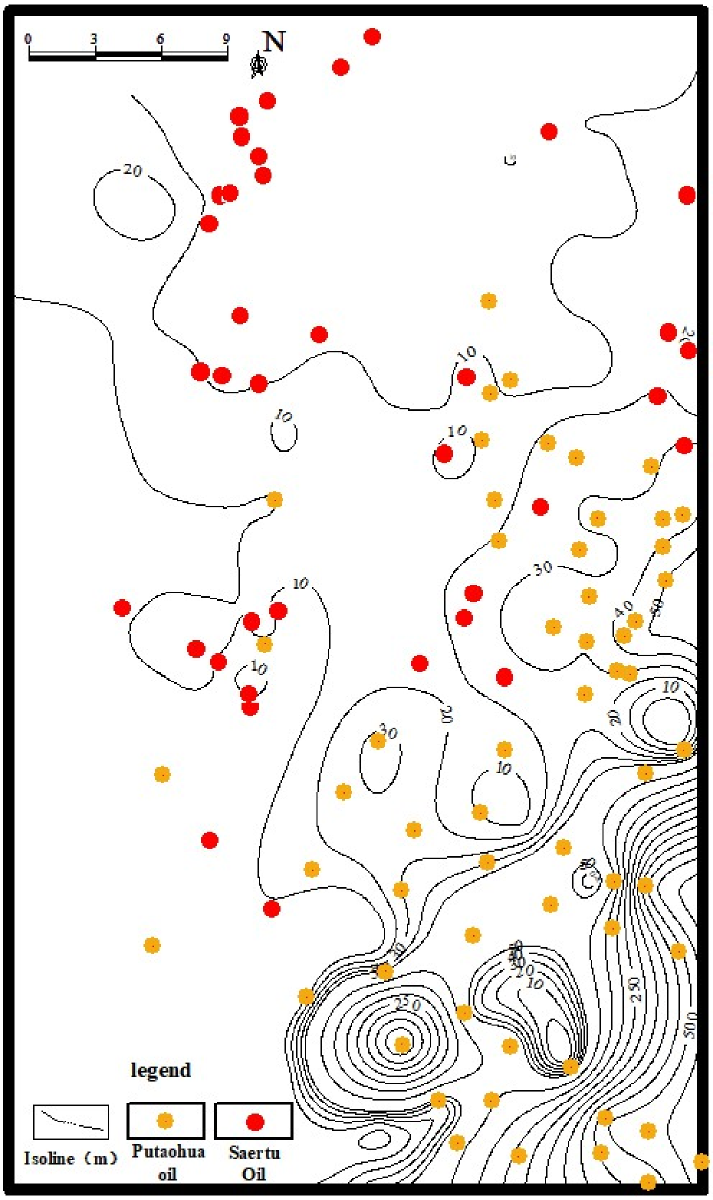

Figure 4. Thickness distribution map of the Sapu mudstone barrier in the Bayan Chagan Area.

Three-dimensional seismic data interpretation identifies three types of faults, including source-connected faults, channels, and barriers at the Sapu cap rocks in the Bayan Chagan Area (Figure 5). However, not all of them can act as a pathway for Putaohua hydrocarbon fluid migrating to the overlying Saertu reservoir and Heidimiao reservoir. Only source-connected faults that were opened during oil charging (cutting T02 and T2 reflectors or overlapping other source-connected faults) could act as channels. Figure 6 shows that channels are well developed in the whole Bayan Chagan Area except the northwest, extending along the NS direction.

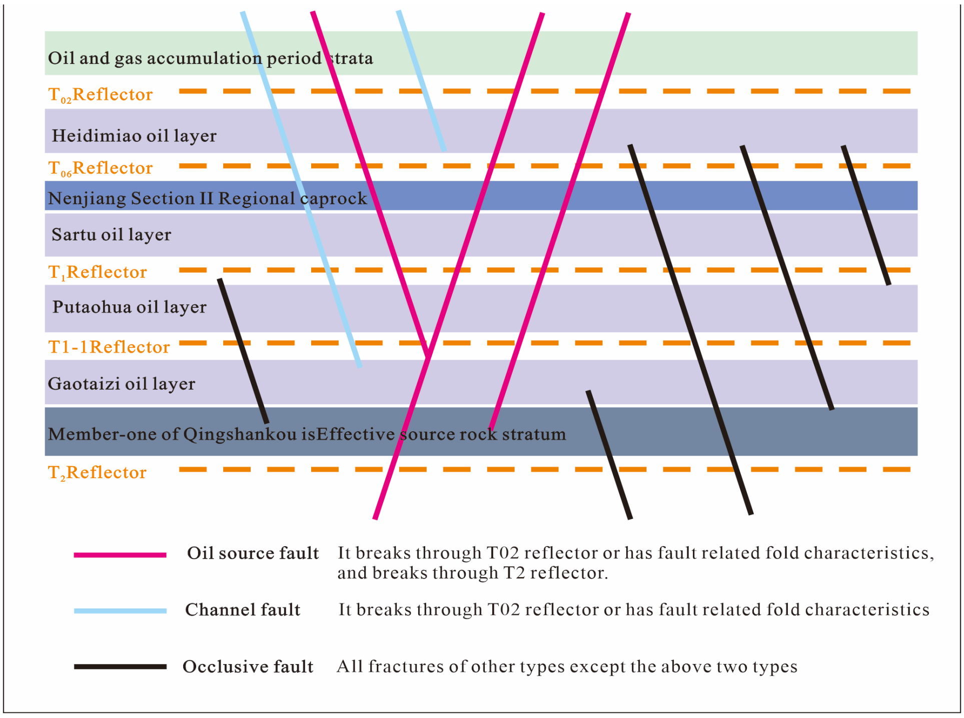

Figure 5. Fault type classification in a typical profile in the Bayan Chagan Area.

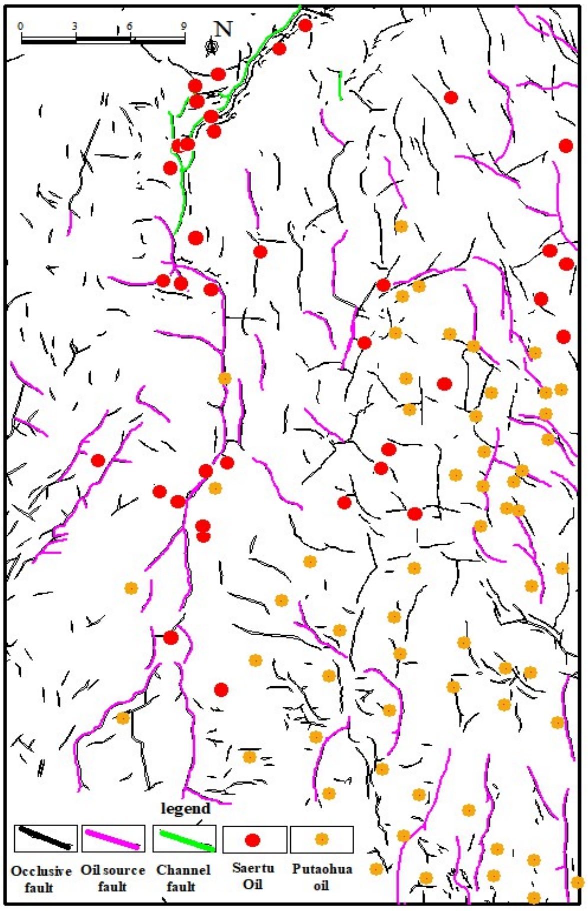

Figure 6. Distribution of migrated hydrocarbon fluid at the Saertu reservoir and the Heidimiao reservoir from the Putaohua reservoir in the Bayan Chagan area.

The connected thickness was determined via Sapu mudstone thickness and related fault throws, which were arranged from small-scale to large-scale. After that, hydrocarbon fluid distribution above and below the Sapu mudstone was determined, and is described in Figure 7, which exhibits that a maximum connected thickness of 20 m was required for Putaohua hydrocarbon fluid migration to the overlying Saertu reservoir in the Bayan Chagan Area. After that, the Sapu mudstone thickness and fault throw in the Bayan Chagan Area were calculated to determine the connected thickness, and they were marked and mapped to exhibit its lateral variation (Figure 8). Finally, the hydrocarbon fluid migration from the Putaohua reservoir to the overlying Saertu reservoir was obtained and found to have the maximum connected thickness (red in Figure 8). Figure 8 shows that all hydrocarbon fluid discovered from the Saertu reservoir in the Bayan Chagan Area is at the top of the adjusted Putaohua reservoir, while no hydrocarbon fluid was discovered at the Saertu reservoir and where no adjustment occurred at the Putaohua reservoir. However, this could have occurred where the connected thickness was greater than the maximum value required for upward hydrocarbon fluid migration. Drilling and seismic data also reveal that the regional mudstone caprock at the second member of the Nenjiang Formation was developed above the Saertu reservoir. Figure 9 shows that it is widely distributed in the Bayan Chagan Area, especially at the southeast, with the maximum thickness is >500 m. The thickness gradually decreases from the southeast to its surrounding areas and is less than 100 m in a small part of the west.

Fault motions in the Bayan Chagan Area were smooth, with throws of source-connected faults at the second member of the Nenjiang Formation reaching <70 m. In other words, the connected thickness at the second member of the Nenjiang Formation is greater than at the threshold, where hydrocarbon fluid generated from the Qingshankou source rock cannot migrate through the Nenjiang cap rocks to the Heidimiao reservoir. The hydrocarbon fluid discovered at the Heidimiao reservoir was generated from the Nenjiang source rock, which was confirmed by the oil-source correlation. Therefore, the Putaohua hydrocarbon fluid cannot pass through the regional cap rock at the second member of the Nenjiang Formation and migrate to the overlying Heidimiao reservoir.

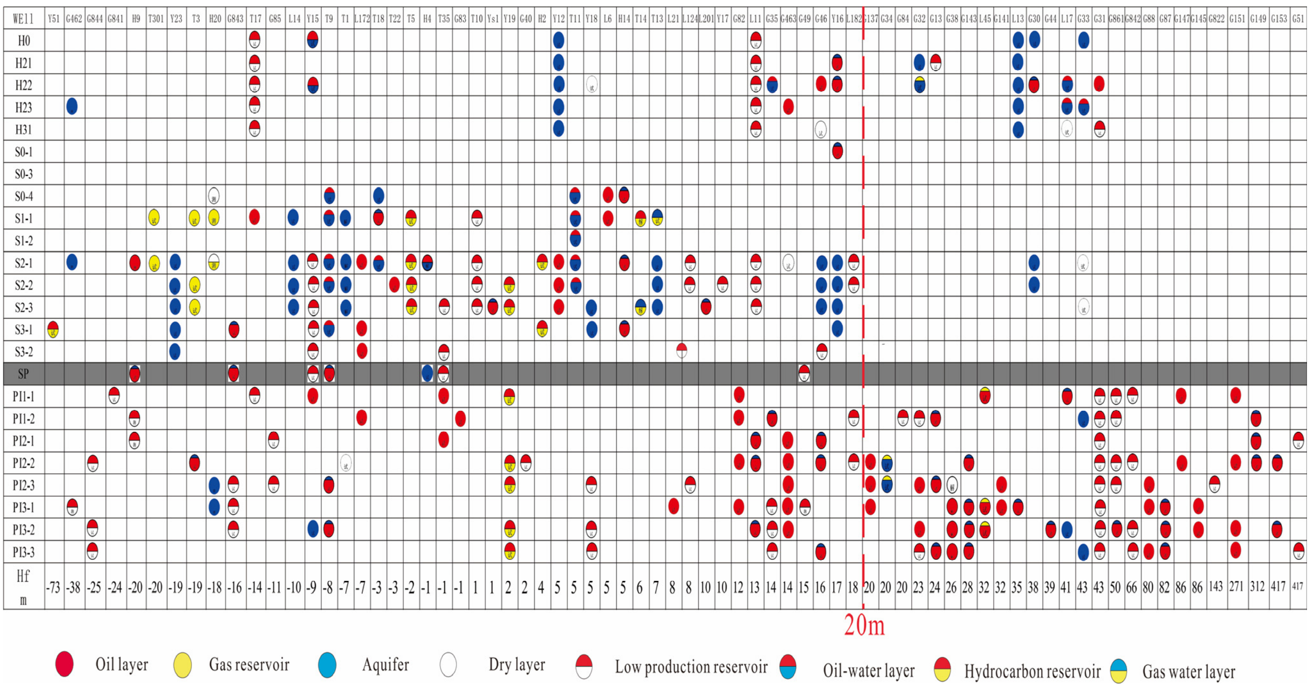

Figure 7. Determination of the maximum thickness of Sapu mudstone barrier required for hydrocarbon fluid migration from the Putaohua reservoir to the overlying Saertu reservoir in the Bayan Chagan Area.

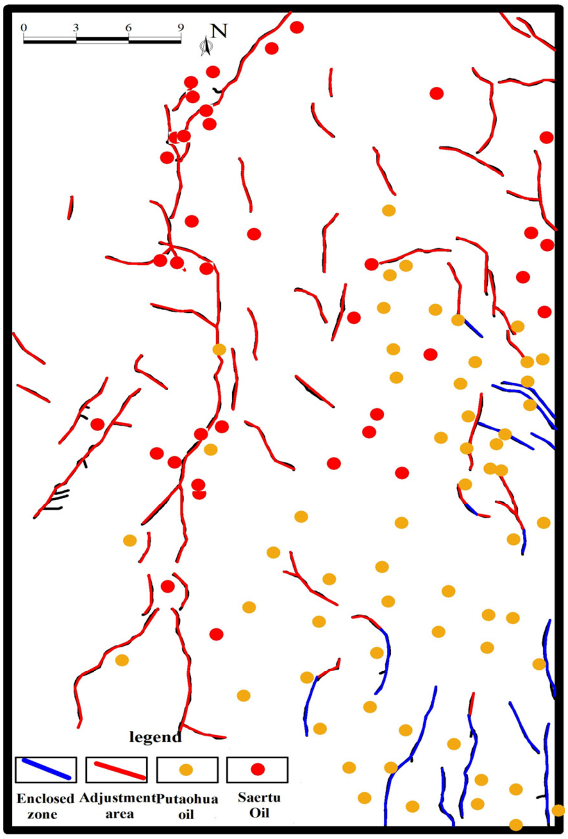

Figure 8. Distribution of migrated hydrocarbon fluid at the Saertu reservoir from the Putaohua reservoir in the Bayan Chagan Area.

Figure 9. Thickness of mudstone cap rock at Nen-2 member in the Bayan Chagan Area.

4. Conclusions

(1) The connected thickness of the overlying cap rocks being smaller than the maximum connected thickness required for hydrocarbon fluid migration (approx. 20 m) is responsible for hydrocarbon fluid migrating from the underlying intervals to the overlying reservoir.

(2) The relationship between the connected thickness of the overlying cap rocks and oil/gas distribution confirms that the maximum connected thickness required for hydrocarbon fluid migration is the minimum thickness where hydrocarbon fluid is distributed above and below it.

(3) The adjusted Putaohua oil reservoir was distributed near the Talahai fault and the Bayanchagan fault, rather than the Gulong sag in the southwest of the study area, where oil migrated vertically through the Sapu interlayer to the overlying Saertu reservoir. Thick mudstone cap rocks in the second member of the Nenjiang Formation made it difficult for hydrocarbon fluid to migrate to the Heidimiao reservoir. This agrees well with hydrocarbon fluid distribution at the Putaohua, Saertu, and Heidimiao reservoirs in the Bayan Chagan Area, indicating that this method is feasible for predicting hydrocarbon fluid migration through faulted cap rocks.

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Conflicts of Interest: B.Z. is employed by the Northeast Petroleum University. The remaining authors declare that the research was conducted in the absence of any commercial or financial relationships that could be construed as potential conflicts of interest.

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