Research on reservoir bed heterogeneity, interlayers and seal layers and controlling factors of 2+3 sands of upper second member, Shahejie Formation, in the west of the Pucheng Oilfield

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Abstract: Terminal fans have formed the sedimentary system of the 2+3 sands of the upper second member, Shahejie formation in the west of the Pucheng Oilfield, Bohai Bay Basin, East China. Based on well logging data and physical properties of the reservoir beds, the 2+3 sands were divided into 16 sublayers. The heterogeneity of reservoir beds and distribution of interlayers and seal layers in the 2+3 sands were investigated. The intra-layer heterogeneity and inter-layer heterogeneity primarily belong to the severely heterogeneous classification. The spatial differentiation of sedimentary microfacies resulted in a change of reservoir bed heterogeneity, strong in the middle and southern parts, weak in the northern part. Spatial distribution of interlayers and seal layers is dominated by sedimentary microfacies, and they are thick in north-eastern and middle parts, thin in the south-western part.

Key words: Sedimentary system, terminal fan, reservoir bed heterogeneity, interlayer and seal layer

1 Introduction

The Dongpu Sag is a secondary unit of the Linqing Depression in the Bohai Bay Basin, East China, extending in the NNE direction; the area is about 5,300 square kilometers. The Pucheng Oilfield is located in the north of the Dongpu Sag (Fig. 1). Regionally it is positioned in the north of the central uplift belt of the Dongpu Sag. The Pucheng structure is an inherited structure uplifted from the low-lying land, and its structural configuration is a long-axis anticline complicated by faults, 15 kilometers in the north-south orientation, and 4.5 kilometers in the east-west orientation.

The Dongpu Sag is a rifted basin developed in the late stage of the Yanshan Movement in the late Mesozoic, and the ascending order of stratigraphic sequence is Archean, Paleozoic, Mesozoic, and Cenozoic. The Cenozoic is divided into Paleogene, Neogene, and Quaternary. The second member of the Shahejie Formation, Paleogene is the major oil-bearing formation in the Pucheng Oilfield, developed in the fluvial-terminal fan deposit in the shore-shallow lake environment (Stanistreet and McCathy, 1993). It can be subdivided into upper second member and lower second member. The upper second member can be further divided into seven sand layers, sands 1 to7. The sands 1+3 are mainly medium to thin siltstone frequently interbedded with grayish green and
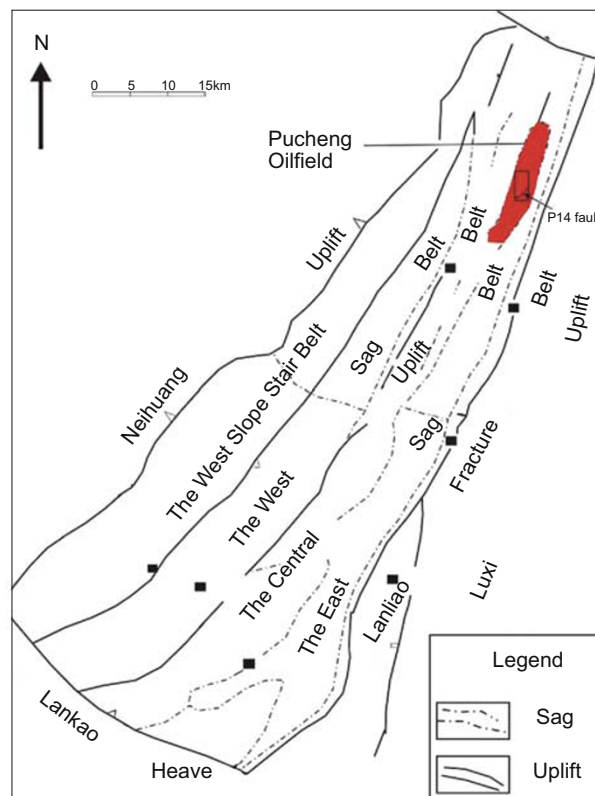

Fig. 1 Location of Pucheng Oilfield and the study block

light brown mudstone and sandy mudstone. The sands 4+7 are lenticular fine sandstone, interbedded with grayish-green, grayish yellow and light brown mudstone (Fig. 2). In these seven sand layers, the sands 2+3 were the target of this study. According to the cycle of sedimentation and oil-bearing features, the sand 2 was further divided into 7 sub-layers and the sand 3 was further divided into 9 sub-layers. The stratigraphic column of Cenozoic formations in the Pucheng Oilfield is shown in Fig.2.

The 2+3 sands were mainly developed on the margin of the overspreading-shrinking lake basin. During the sedimentary period of the sand 3, sediments prograded towards the lake basin, with the supply of sediments from the Luxi Uplift. The deposits were mainly gray and light brown mudstone interbedded with silty sandstone. At the sedimentary time of the sand 2, sediments retrograded towards the land, with the supply of sediments also from the Luxi Uplift, but the hydraulic conditions of this time weakened compared with the sand 3, so the size and total thickness of sand bodies were smaller. The deposits were also mainly gray mudstone and silty sandstone.

2 The research materials and methods

2.1 Reservoir bed heterogeneity of 2+3 sands, upper second member, Shahejie Formation

Porosity, permeability and porous structure are fundamental parameters measuring the capability of preserving and transporting fluids in the formation rocks (Liu et al, 2001). Porosity controls the amount of fluids preserved, additionally, permeability controls the oil/gas productivity in the reservoir bed. The lithologic properties of reservoir bed are not homogeneous, and they are mainly determined by the sedimentary environment. Sedimentary environments are not the same, and the types of heterogeneity are different. Reservoir bed heterogeneity can be represented by the porosity, permeability, and thickness of sand bodies, as well as the distribution of interlayers and seal layers. Reservoir bed heterogeneity controls the distribution, accumulation and productivity of oil/gas (Zhang and Chang, 2004).

Here, the heterogeneity of the sands 2+3 was studied from three aspects: intra-layer heterogeneity, inter-layer
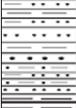
Stratgraphic sequence				Menber	Code	Thickness m	Litho-logical characteristics	Lithological characteristics	Sedimentary facies
Erathem	Subsystem	Series	Formation						
Cenozoic	Neogene Paleogene	Miocene Oligocene	Shahejie formation	Upper first member	Es$_1^U$	100 | 200		Mainly grey, deep grey mudstone and silt, sandstone, containing limestone	Shallow-medium deep lacustrine facies
				Lower first member	Es$_1^L$	50 | 400		Mainly grey, deep grey mudstone containing halolite	Delta facies
				Upper second member	Es$_2^U$	120 | 600		It can be divided into 7 sands, brown mudstone, interbedding thinner silty sandstone in 1+3 sands; grey mudstone interbedding sandstone in 4+7 sands	Terminal fan shore-shallow lacustrine facies
		Eocene		Lower second member	Es$_2^L$	240 | 550		Mainly purplish red, light brown mudstone and grey sandstone containing carbonate sandstone	Fluvial-flood plain faices
				Upper third member	Es$_3^U$	100 | 600		Mainly grey,deep grey mudstone interbedding silty sandstone, the upper part of which are calcareous sand or sagstone	Medium deep-deep salt lacustrine facies
				Middle third member	Es$_3^M$	300 | 500		Mainly deep grey schist, halolite and silty sandstone	Delta, turbidity and fan-delta facies

Fig. 2 Stratigraphic column of Cenozoic formations in Pucheng Oilfield (study sands in red frame)

heterogeneity and spatial heterogeneity (Xia et al, 1999).

2.2 Interlayers and seal layers of 2+3 sands, upper second member, Shahejie Formation

Seal layer or barrier is the impermeable rock which can stop or restrict the flow of fluid, and its area is larger than half of the flow unit (Li and Li, 2003). Its thickness varies between centimeters and meters. The interlayer is the

relatively impermeable sub-layers in the sand body, which can not restrict the fluid flow completely, and their area is often smaller than half of the flow unit. Their thickness is often between several centimeters and tens of centimeters, and their their seal properties are inferior to seal layer (Zhou and Li, 2001).

Observation of the core samples of the sands 2+3 from multiple cored wells, and the data of well-logging, e .g. SP,

MR, and GR indicated that the interlayer could be classified into three types: muddy interlayer, silty sand interlayer and calcareous cemented interlayer and the seal layer could be classified into three types: uniformly distributed seal layer, streak-like distributed seal layer and fragmentary seal layer.

3 Results

3.1 Reservoir bed heterogeneity of 2+3 sands, upper second member, Shahejie Formation

3.1.1 Intra-layer heterogeneity

Intra-layer heterogeneity is defined as the variation of reservoir bed physical properties in the vertical direction in a single sand body. It reflects the overall degree of heterogeneity in terms of physical properties, and can be described by several fundamental parameters below (Ji, et al, 2007).

1) Differential Jk ($Jmax/Jmin$): the ratio of the maximum and minimum of permeability; the larger the ratio, the stronger the heterogeneity.

2) Breakthrough coefficient Tk ($kmax/k$): the ratio of the maximum and mean of permeability. When Tk is less than 2, the layer is homogeneous. When Tk is between 2 and 3, the layer is fairly homogeneous. When Tk is greater than 3, the layer is heterogeneous.

3) Coefficient of homogeneity Kk ($k/kmax$): It is the reciprocal of the breakthrough coefficient, which varies form 0 to 1. When it is close to 1, the layer is homogeneous.

4) Coefficient of variation Vk ($\sigma k/k$): The ratio of the standard deviation and mean of permeability. When Vk is less than 0.5, the layer is homogeneous. When Vk is between 0.5 and 0.7, the layer is fairly homogeneous. When Vk is greater than 0.7, the layer is heterogeneous.

Jk, Tk, Kk and Vk values of sub-layers of the 2+3 sands are shown in Table 1. In the sand 2, maximum Jk is 3944.5, and minimum Jk is 132.68; maximum Tk is 8.3, and minimum Tk is 4.23; maximum Vk is 2.75, and minimum Vk is 0.8 .In the sand 3, maximum Jk is 1281.14, and minimum Jk is 233; maximum Tk is 5.87, and minimum Jk is 2.25, maximum Vk is 1.35, and minimum Vk is 0.58.

Because the coefficient of homogeneity is the reciprocal of the breakthrough coefficient, so in the discussions, it is enough to use one of them, and we will use breakthrough

Table 1 Heterogeneity parameters of each sub-layer of 2+3 sands

Sub-layer	Maximum $10^{-3}\mu m^2$	Minimum $10^{-3}\mu m^2$	Mean $10^{-3}\mu m^2$	Differential	Breakthrough Coefficient	Coefficient of homogeneity	Coefficient of variation
0201	276.11	0.07	33.26	3944.5	8.3	0.12	2.75
0202	185.78	0.14	27.19	1327	6.83	0.146	1.98
0203	287.6	0.25	61.59	1173.86	4.67	0.214	0.84
0204	334.36	0.28	25.5	1194.13	5.53	0.181	1.11
0205	334.36	0.18	48.3	1910.6	6.92	0.145	1.50
0206	334.36	2.52	64.55	132.68	5.18	0.193	0.82
0207	314.55	0.35	73.39	898.7	4.23	0.236	0.80
0301	334.36	0.32	85.2	1061.44	3.92	0.255	0.83
0302	371.5	0.29	89.48	1271.37	4.15	0.241	0.82
0303	299.18	0.32	69.83	949.778	4.28	0.234	0.89
0304	334.36	0.46	77.21	734.85	4.33	0.231	0.799
0305	281.54	0.63	73.6	446.89	3.83	0.261	0.83
0306	334.36	0.385	66.29	868.45	5.04	0.198	1.06
0307	334.36	1.44	148.86	233	2.25	0.444	0.58
0308	313.88	0.25	53.32	1281.14	5.87	0.17	1.05
0309	202.58	0.385	40.17	526.18	5.04	0.198	1.35

coefficient here. Based on the generally accepted criteria for classifying heterogeneity (Table 2), the breakthrough coefficients of seven sub-layers in the sand 2 are all greater than 3, coefficients of variation are all greater than 0.7, so the sand 2 is severely heterogeneous. In the sand 3, coefficients of variation of 9 sub-layers are greater than 0.7 except the ninth sub-layer, coefficients of heterogeneity are greater than 3 except the seventh sub-layer, so the sand 3 is also severely heterogeneous. From those data, we consider that the intra-layer heterogeneity of the 2 +3 sands obviously belongs to the type of severely heterogeneous.

Table 2 Criteria accepted generally for classifying reservoir bed heterogeneity

Type of heterogeneity	Boundary value of coefficient of variation	Boundary value of coefficient of homogeneity	Boundary value of breakthrough coefficient
Relatively heterogeneous type	<0.5	>0.5	<2.0
Heterogeneous type	0.5 - 0.7	0.33 - 0.5	2.0 - 3.0
Severely heterogeneous type	>0.7	<0.33	>3.0

3.1.2 Inter-layer heterogeneity

Inter-layer heterogeneity represents the variations of reservoir bed physical properties between sub-layers in the vertical direction, including cycle of sequences, variation of permeability of sub-layers, and distribution of seal layer (Qin and Zhang, 2007).

Some parameters can reflect the inter-layer heterogeneity of reservoir beds, such as the coefficient of variation, breakthrough coefficient, drill-in ratio of seal layer.

Based on the analysis of data from 273 production wells in the western part (Table 3, Table 4), in the sand 2, maximum breakthrough coefficient is 8.3, and minimum breakthrough coefficient is 4.23; maximum coefficient of variation is 2.75, and minimum coefficient of variation is 0.8; maximum drill-in ratio of seal layer is 82.4%, and minimum drill-in ratio of seal layer is 59.2%. In the sand 3, maximum breakthrough coefficient is 5.87, and minimum breakthrough coefficient

is 2.25; maximum coefficient of variation is 1.35, and minimum coefficient of variation is 0.58; maximum drill-in ratio of seal layer is 77.3%, and minimum drill-in ratio of seal layer is 59.2%. According to the criteria for classifying heterogeneity (Table 2), the inter-layer heterogeneity of the 2+3 sands belongs to the type of heterogeneous or severely heterogeneous.

Table 3 Statistical data of inter-layer heterogeneity of 2+ 3 sands, upper second member, Shahejie Formation

Sub-layers	Differential	Breakthrough coefficient	Coefficient of variation
0201	3944.5	8.3	2.75
0202	1327	6.83	1.98
0203	1173.86	4.67	0.84
0204	1194.13	5.53	1.11
0205	1910.6	6.92	1.50
0206	132.68	5.18	0.82
0207	898.7	4.23	0.80
0301	1061.44	3.92	0.83
0302	1271.37	4.15	0.82
0303	949.778	4.28	0.89
0304	734.85	4.33	0.799
0305	446.89	3.83	0.83
0306	868.45	5.04	1.06
0307	233	2.25	0.58
0308	1281.14	5.87	1.05
0309	526.18	5.04	1.35

Table 4 Drill-in ratio of seal layers in 2+3 sands, upper second member, Shahejie Formation

Sub-layers	0201-0202	0202-0203	0203-0204	0204-0205	0205-0206	0206-0207	0207-0301	0301-0302	0302-0303	0303-0304	0304-0305	0305-0306	0306-0307	0307-0308	0308-0309
Drill-in ratio, %	78.1	79.5	82.4	59.2	81.4	62.4	72.4	59.2	59.5	71.9	72.2	70.5	76.8	77.3	70.3

Based on the data of Table 3, the contrast sections of coefficient of variation and breakthrough coefficient are plotted in Fig. 3 and Fig. 4 respectively. It is obvious that the

heterogeneities of sub-layers 0201, 0202, 0308 and 0309 are stronger than other sub-layers.
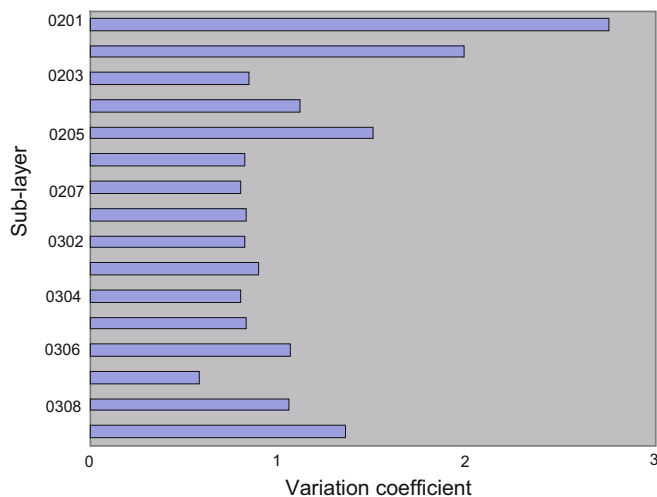
Fig. 3 Coefficient of variation of different sublayers

Fig. 4 Breakthrough coefficient of different sublayers

3.1.4 Spatial heterogeneity of reservoir

Spatial heterogeneity describes the heterogeneity controlled by spatial variation of reservoir beds, including spatial distribution, size and connectivity, as well as the variation of porosity and permeability of sand bodies(Zhang, 1996). It is mostly controlled by sedimentary facies.

The sedimentary environment determines the distribution of sand bodies, which in turn is the main element controlling the distribution of oil and gas (Fisher and Knipe, 2001). During the sedimentary period of the 3 and 2 sands, the sediments mainly came from the Luxi Uplift in the northeast,
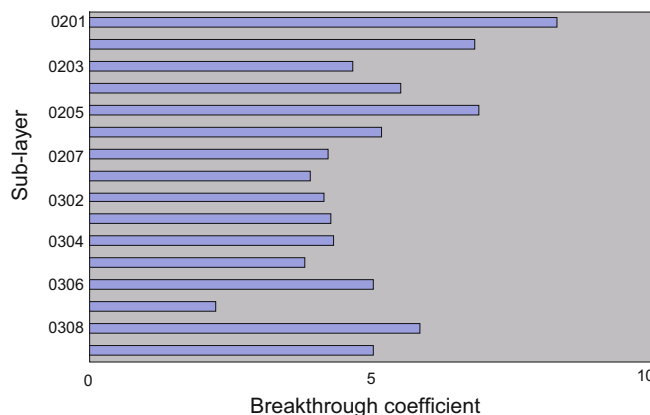
so the distribution of sand bodies extended in the northeast-southwest direction. According to the development of sedimentary microfacies, the orientation of distributary channels also extended in the same direction. Frequent changes and bifurcations of channels generated variation in the distribution of sand bodies, resulting in different reservoir bed qualities of each sub-layer on the plane. Therefore the spatial distribution of porosity and permeability is heterogeneous (Zhang et al, 2007). The statistical data of porosities of the 2+3 sands are shown in Table 5.

Based on the analysis of the areal distribution map of porosities (Fig.5, Fig. 6) , the isolines of porosity are dense, especially around some wells, e.g. around Well 2-8 in the

Table 5 Stratistical data of porosities of 2+3 sands, upper second member, Shahejie Formation

Sub-layer	0201	0202	0203	0204	0205	0206	0207	0301	0302	0303	0304	0305	0306	0307	0308	0309
Maximum porosity	28.5	29.2	39.65	37.3	30	49.15	39.5	52.5	38.25	33.3	39.45	30	30	30	29.7	28.3
Minimum porosity	8.3	4.5	10.65	9.3	9.6	12.5	2	11.3	13.1	11.8	12.1	11	11.6	12.2	10.8	11.2
Mean porosity	13.7	15.3	23.5	22.97	20.35	24.38	23.6	24.36	24.51	23.69	23.99	23.68	23.2	25	21.8	20

areal distribution map of porosities of the sand 2, around Well 3-106 in the areal distribution map of porosities of the sand 3. Around these wells, the value of porosity decreases quickly, which reflects that the spatial heterogeneity belongs to the

type of strong heterogeneity. At the same time, the porosities of most wells in the western part are larger than 20%, according to the criteria for classifying and evaluating detrital reservoir beds (Table 6), such porosities belong to medium

Table 6 Criteria for classifying and evaluating detrital reservoir beds

Category	High porosity and permeability	Medium porosity and permeability	Low porosity and permeability	Ultra-low porosity and permeability
Porosity, %	≥25	15 - 25	10 - 15	<10
Permeability, ×10^{-3}μm^2	≥500	10 - 500	1 - 10	<1

porosity (Xie and Zhang, 2007).

In light of the analysis of the areal distribution map of permeabilities (Fig. 7, Fig. 8), the isolines of permeability are also dense; the permeabilities of most wells in the western part are greater than $100\times10^{-3}\mu m^2$. According to the criteria for classifying and evaluating detrital reservoir beds (Table 6), such permeabilities belong to medium permeability.
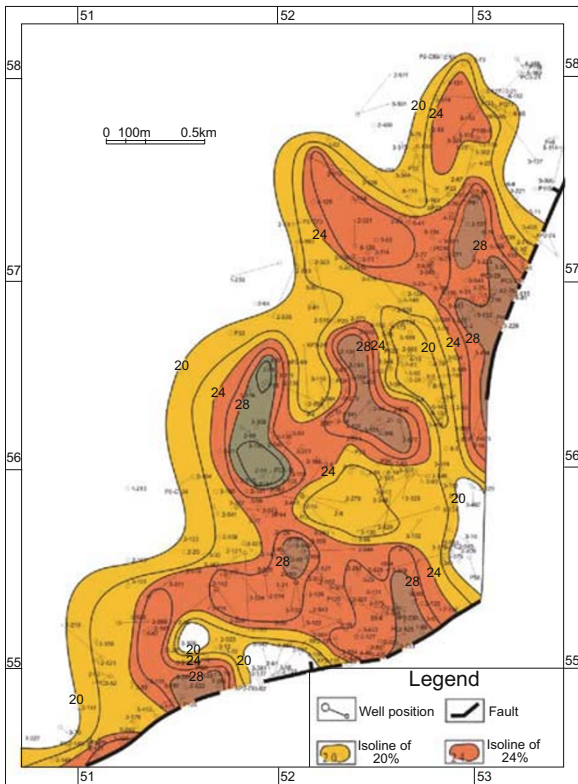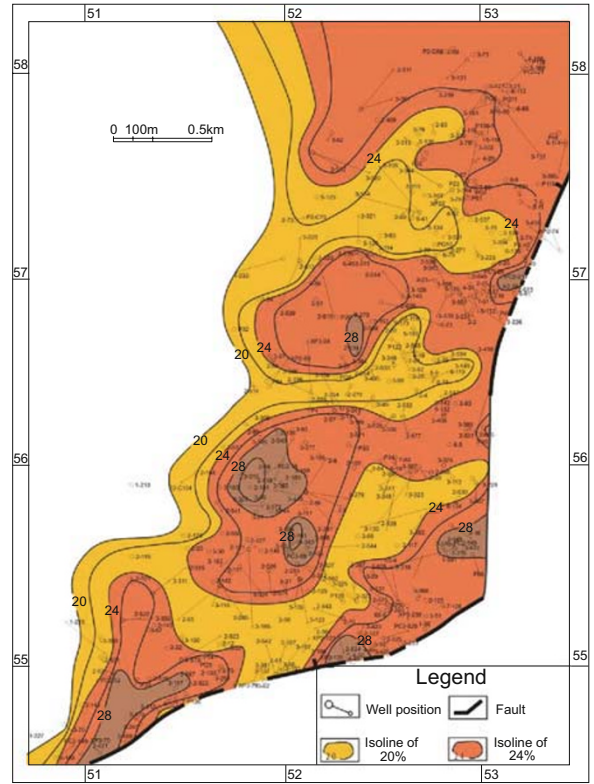

Fig. 5 Areal distribution map of porosities of sand 2

Fig. 6 Areal distribution map of porosities of sand 3
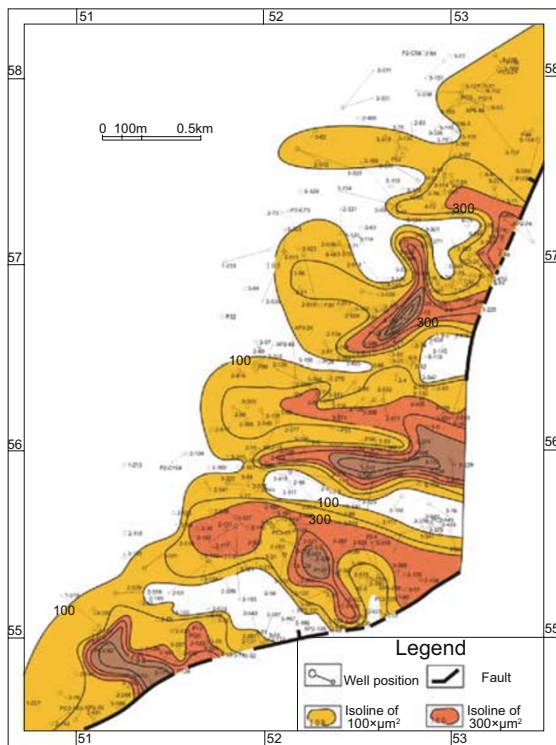
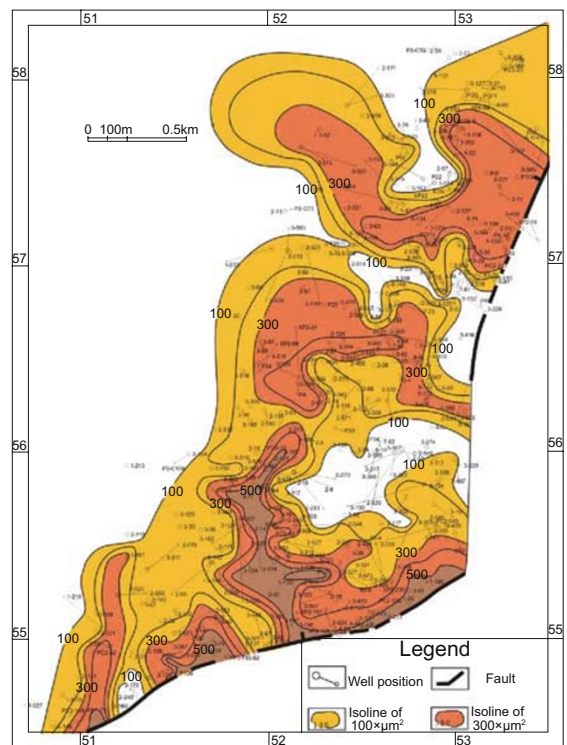**Fig. 7** Areal distribution map of permeabilities of sand 2

Fig. 8 Areal distribution map of permeabilities of sand 3

3.2 Interlayers and seal layers

3.2.1 Formation types of interlayers and seal layers of 2+3 sands

Observation of core samples of the 2+3 sands from multiple cored wells and the data of well-logging, e.g. SP, MR, and GR indicated that interlayers can be classified into three types (Wang and Zhang, 1996): muddy interlayer, silty sand interlayer and calcareous cemented interlayer, and seal layers could be classified into three types: uniformly distributed seal layer, streak-like distributed seal layer and fragmentary seal layer.

Interlayers and seal layers of the 2+3 sands were mainly developed in three sedimentary micro-environments: proximal overbank, distal overbank, and basinal zone (Zhu et al, 2004).

The proximal overbank microfacies were located on both sides or on the front edge of the distributary channels, and were developed when the flood in channels spread over in flood periods. The components are mainly silty sand, with a high content of mud. The sedimentary architectures are mainly the alternations of light-brown or grayish green mudstone and silty sandstone. The distal overbank microfacies were developed on the front edge of the proximal overbank, and the sediments are mainly alternations of silty sandstone, pelitic siltstone and light brown mudstone, with a high content of mud. The basinal zone microfacies were developed on the plain in front of the distal overbank. Their lithology is mainly light brown and grayish green mudstone, alternating with thin pelitic siltstone (Sean and Henrik, 1993).

3.2.2 Areal distribution of seal layers

Table 7 Statistical data of seal layers in 2+3 sands upper second member, Shahejie Formation

Sub-layers	0201-0202	0202-0203	0203-0204	0204-0205	0205-0206	0206-0207	0207-0301	0301-0302	0302-0303	0303-0304	0304-0305	0305-0306	0306-0307	0307-0308	0308-0309
Max, m	9.1	6.4	6.6	8.5	8.6	6.6	7.2	6.1	6.4	10.8	9.5	6.8	6.4	6	9
Min, m	0.2	0.1	0.1	0.2	0.2	0.2	0.2	0.1	0.2	0.2	0.2	0.2	0.3	0.2	0.5
Mean, m	2.03	1.89	2.23	1.89	2.55	1.38	1.85	1.44	1.74	1.93	1.5	1.48	1.50	1.89	1.76
drill-in ratio, %	78.1	79.5	82.4	59.2	81.4	62.4	72.4	59.2	59.5	71.9	72.2	70.5	76.8	77.3	70.3

According to the analysis, the distribution of seal layers between sub-layers was controlled by the sedimentary microfacies of proximal overbank and distal overbank (Zhang et al, 2007), which determined the vertical and spatial features of seal layers.

In the whole, the mean thickness of seal layers is larger, and the thickness is always between 0 and 5 meters; the drill-in ratio of seal layers in each sub-layer is higher (Table 7). Some seal layers are up to 8 meters in some places. The drill-in ratio of seal layers between 0 and 5 meters is more than 50%, because of the specific genetic environments. The seal layers are thicker in the overbank zone, while thinner in the zone where the channels were concentrated.

The areal distribution of seal layers of S_2^1-S_2^2, S_2^6-S_2^7, S_3^1-S_3^2, S_3^8-S_3^9 is plotted in Fig. 9, Fig. 10, Fig.11, and Fig. 12 respectively. Based on the analysis of these plots, in the whole western part, thick seal layers are distributed in the northeast and middle. The thicknesses are between 5 and 6 meters, decreasing in the southwest direction, down to less than 3 meters. This situation is related to the supply of sediment from the Luxi Uplift in the northeast.

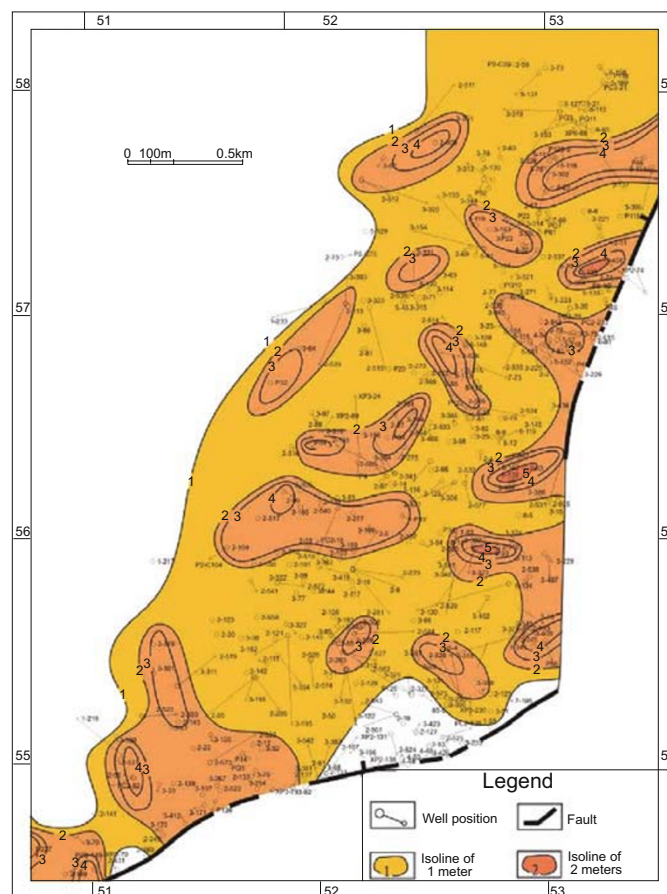### 3.2.3 Areal distribution of interlayers
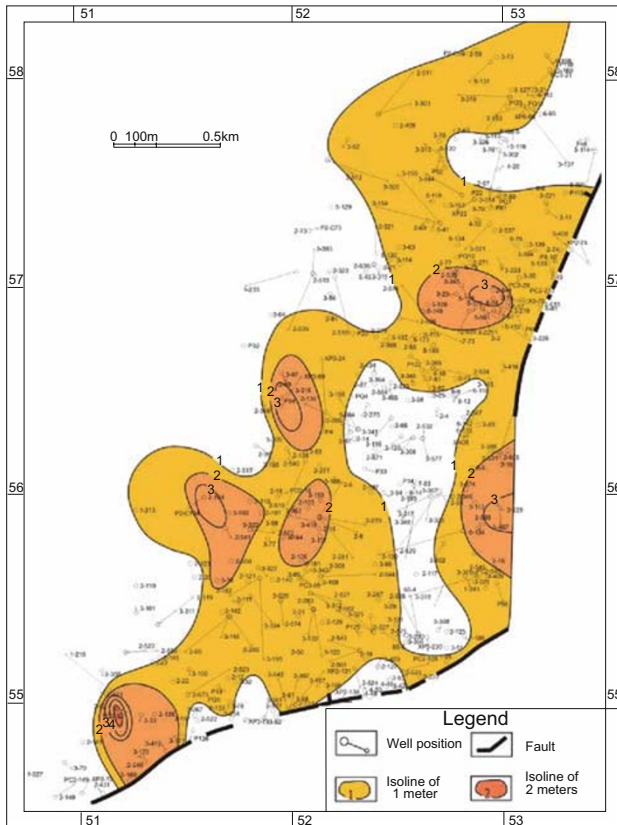

Fig. 9 Areal distribution of seal layers in S_2^1 and S_2^2

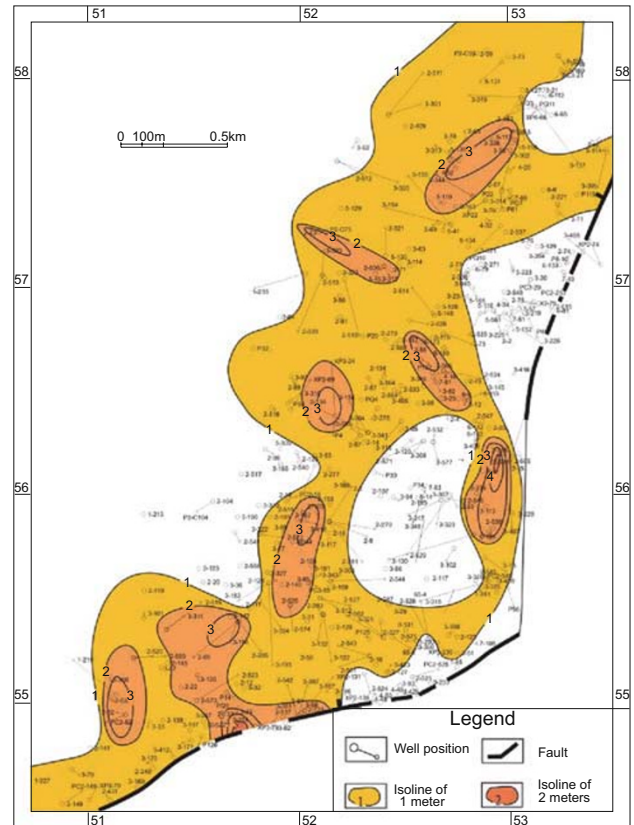**Fig. 10** Areal distribution of seal layers in S_2^6 and S_2^7

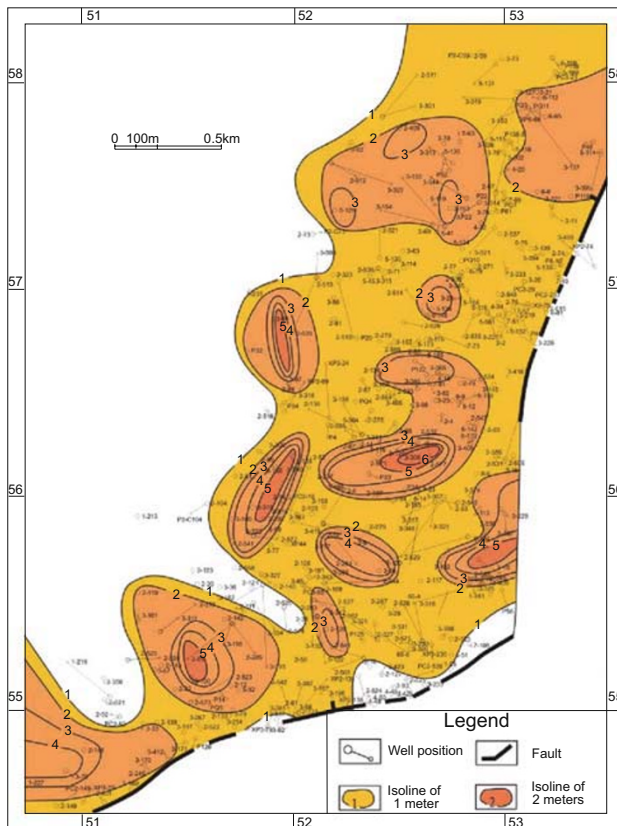**Fig. 11** Areal distribution of seal layers in S_3^1 and S_3^2

Fig. 12 Areal distribution of seal layers in S_3^8 and S_3^9

From the statistical data of interlayers (Table 8), the thickness of interlayers is thinner than the thickness of seal layers, and is between 1.33 and 3 meters. The spatial distributions of interlayer of S_2^1, S_2^7, S_3^1 and S_3^8 are plotted in Fig. 13, Fig.14, Fig. 15, and Fig.16 respectively.

On the basis of these plots, the thicknesses of interlayers are apparently thinner than those of seal layers. The thick interlayers are mainly formed in the northeastern and middle parts, and are mostly between 3 and 5 meters. The interlayers less than 1 meter are located in the southwestern and southeastern parts, decreasing from northeast to southwest. The reason is that the distributary channels were more well-developed in the northeastern and middle parts than the southwestern part which is related to the development of proximal overbank and distal overbank deposits from the northeast.

Table 8 Statistical data of interlayers of 2+3 sands, upper second member, Shahejie Formation

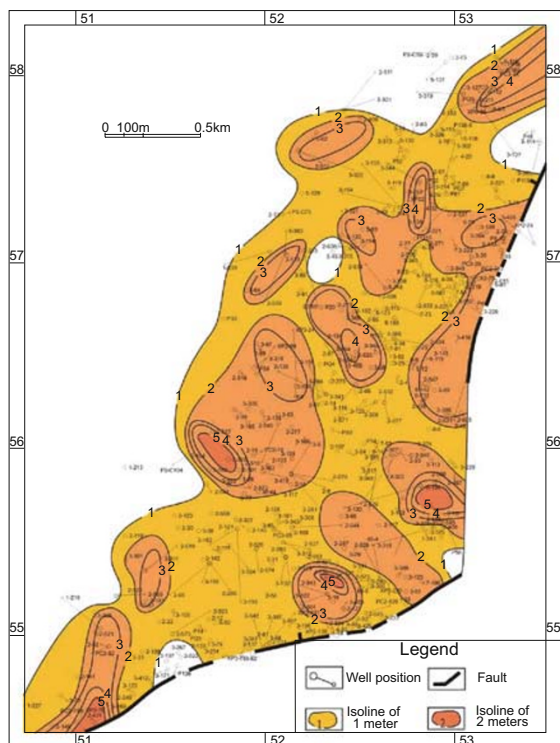| Sub-layers	0201	0202	0203	0204	0205	0206	0207	0301	0302	0303	0304	0305	0306	0307	0308	0309
Max, m	8.5	5	5.5	5.5	5.4	7.1	5	5.6	5.8	5.7	4.9	4	4.6	5.6	8.5	10
Min, m	0	0	0	0.1	0	0	0	0.2	0.4	0.2	0	0.4	0.6	0.3	0.4	0.4
Mean, m	2.13	1.8	1.36	1.33	20.7	1.65	1.35	1.83	1.68	1.63	1.59	1.3	1.45	1.38	1.79	2.72

Fig. 13 Areal distribution of interlayers of 1st sub-layer of sand 2
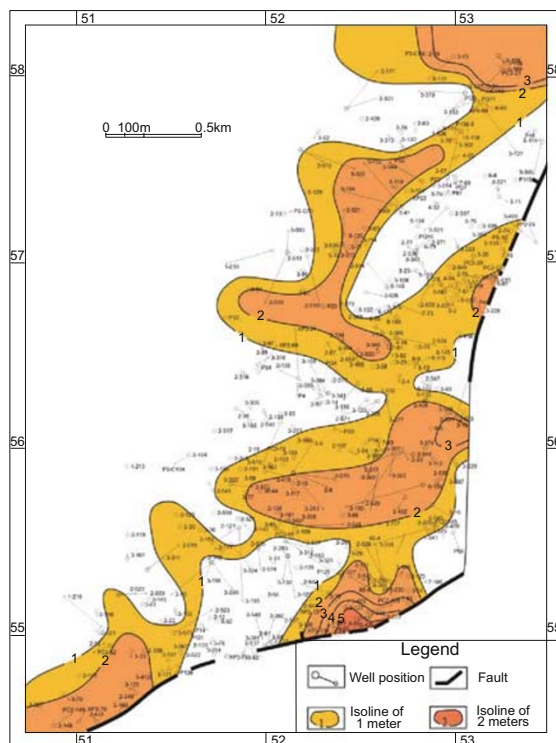

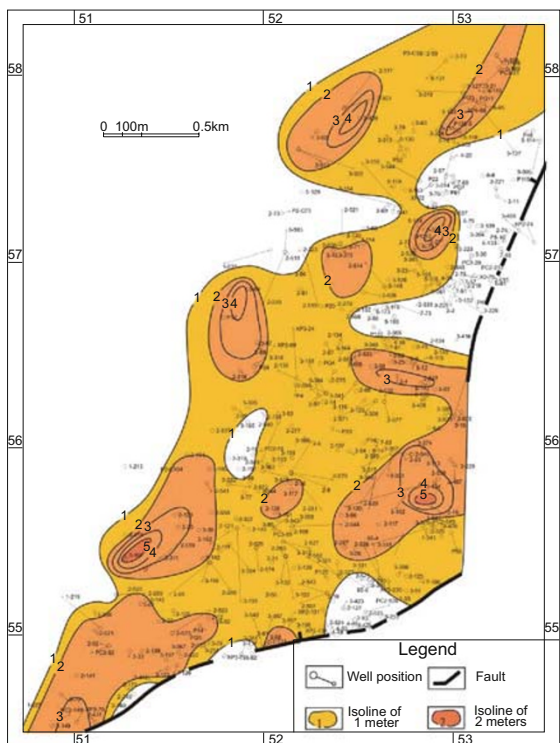**Fig. 14** Areal distribution of interlayers of 7th sub-layer of sand 2

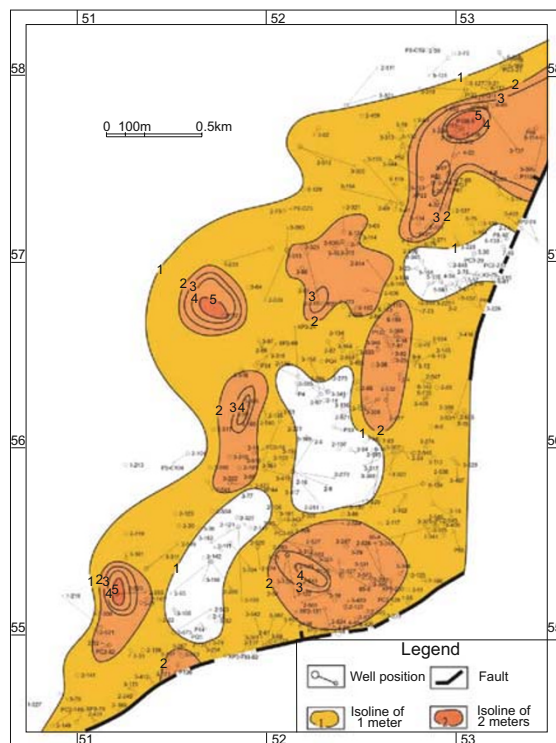**Fig. 15** Areal distribution of interlayers of 1st sub-layer of sand 3

Fig. 16 Areal distribution of interlayers of 8th sub-layer of sand 3

4 Conclusions

1) The intra-layer heterogeneity and inter-layer heterogeneity of the 2+3 sands, Shahejie Formation in the Pucheng Oilfield mainly belong to the severely heterogeneous category.

2) Spatial heterogeneity is mainly controlled by sedimentary facies, and the differentiation of microfacies caused the varying degrees of heterogeneity. Additionally, the heterogeneity in the northern and middle parts is higher than that in the southern part.

3) Observation of core samples of the 2+3 sands from multiple cored wells and the data of well-logging, e.g. SP, MR, and GR indicated that interlayers could be classified into three types: muddy interlayers, silty sand interlayers and calcareous cemented interlayers and seal layers could be classified into three types: uniformly distributed seal layers, streak-like distributed seal layers, and fragmentary seal layers.

4) Interlayers and seal layers are thicker in the northeastern and middle parts, and thinner in the southwestern part.

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