

Chapter 2

Reservoir Direction Characteristics Investigation and Permeability Distribution Law

2.1 Directional Characteristics of the Reservoir

To improve oilfield development and increase oil recovery are always the focus of oilfield development workers' concern. The way to improve oilfield development efficiency can be described as the following two parts. One is called IOR (improved oil recovery), that is, changing the well pattern, well type, and working system of the formation to improve oilfield development. The other is called EOR (enhanced oil recovery), that is, changing displacement agent to enhance oil recovery. The former might be more economical and sustainable, with no second pollution of the reservoir, and can continuously improve and enhance oil recovery at the same time so as to make the full use of resources. IOR is applied more often in foreign oilfields, in which rapid progress is made in the relevant development technology of different well types. Through the analysis of the development characteristics of heterogeneous reservoirs and the geological characteristics of oil-and-gas reservoirs, the author puts forward a new concept of reservoir directivity and characteristics of direction-controlled development and discusses the strategy of improving oilfield development through reasonably coupling reservoir directivity to the controllable direction.

After a long process of deposition, crustal movement, underground stress, oil-and-gas migration, and so on, oil-and-gas reservoirs have developed their inherent geological features. Through the analysis of these features, a conclusion can be made of the direction of the reservoir, which has an important influence on the development effect. A systematic analysis of the inherent directional characteristics of the reservoir plays an important role in guiding the implementation of reasonable development strategies and specific development technologies for oilfields. The directions mainly include the source direction, depositional direction, main permeability direction, fracture direction, and principal stress direction.

2.1.1 Provenance Direction and Depositional Direction

Since the formation of the Earth, its texture, structure, material composition, and surface morphology have been constantly moving and changing in the long geological ages. Under the influence of various geological stresses, the rocks exposed on the surface of the earth continually roll down slopes off the bedrock, and then, they are carried by wind and water to appropriate locations, where they deposit to form new sedimentary rock layers. The main research object of provenance analysis is the terrigenous detrital components together with their structures and tectonic characteristics, and the basic principle is mechanical differentiation. Along the provenance direction, sediment grain size and color vary according to a certain tendency. As long as the rule of variation of delta deposits is identified and the distribution of their sedimentary facies is defined, the source direction can be determined. This helps to find out the relationship between the erosional zone and the deposition zone, uplift and depression, protrusion and sagging, etc., during the development of the area studied. There are many ways of judging the provenance direction, such as the glutenite's size, composition, thickness and its content change, contrast of geochemical characteristics of the rocks, laminae tendency of cross-beddings, and the variation pattern of rock colors.

Provenance direction refers to the main provenance direction of sediment or transport direction. No matter what type of deposition, it has a clear provenance direction. There may be more than one provenance direction in the same deposition, and provenance directions are different in different depositional periods. By determining the provenance direction, we can analyze the sedimentary distribution characteristics, size, extending direction, physical properties of sand bodies, and so on according to the provenance direction. Figure 2.1 shows a typical depositional mode of the fan delta front and front fan delta. There are two provenance directions. The developed sedimentary micro-facies consist of the front underwater distributary channels, distributary interchannel areas, mouth bar, front sheet sand, and front fan delta mud. By determining the provenance direction, we can determine the combination of different micro-facies and their contact relationship.

Figure 2.2 shows a distribution map of the reservoir sedimentary facies of a block of an oilfield in northeast China. The provenance direction in the west of the block is about 50° northwest; the central provenance direction is nearly north-south, and the eastern provenance is NE 45° . The sand extending direction is consistent with the direction of the provenance. From a macro point of view, the depositional process of the region is multi-provenance deposition.

To figure out the direction of sediment transport and to analyze paleosedimentary environments and the distribution of pay zones are very important for finding favorable exploration direction. The study of provenance is of great significance for understanding and identifying favorable sedimentary facies of the area studied and the distribution of reservoir sand bodies and for looking for favorable oil-and-gas reservoirs. Besides, to find out the distribution characteristics of sand bodies which are based on the provenance sedimentary characteristics is also very important for the deployment of the well pattern and effective control of oil sand bodies.

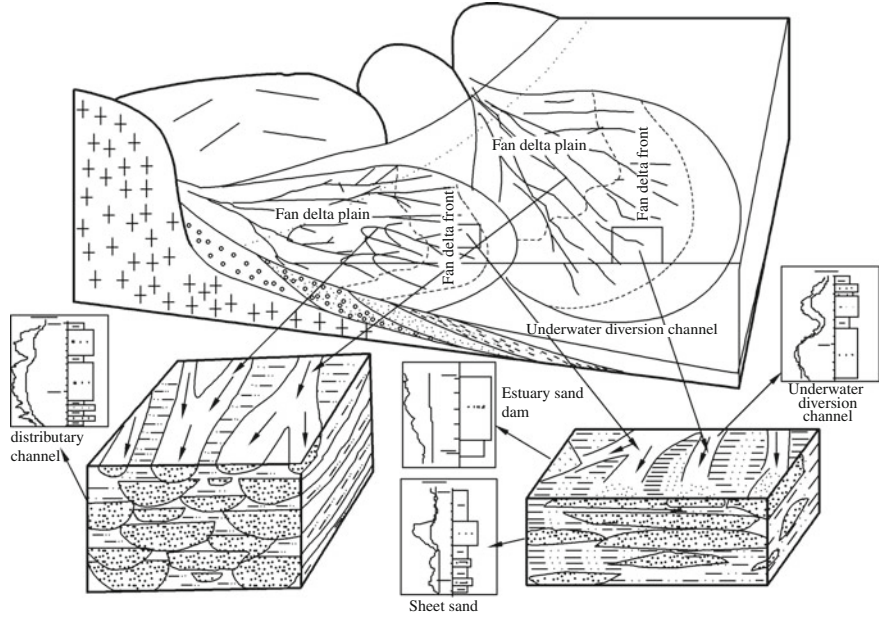


Fig. 2.1 Fan delta front and pro-fan delta depositional model

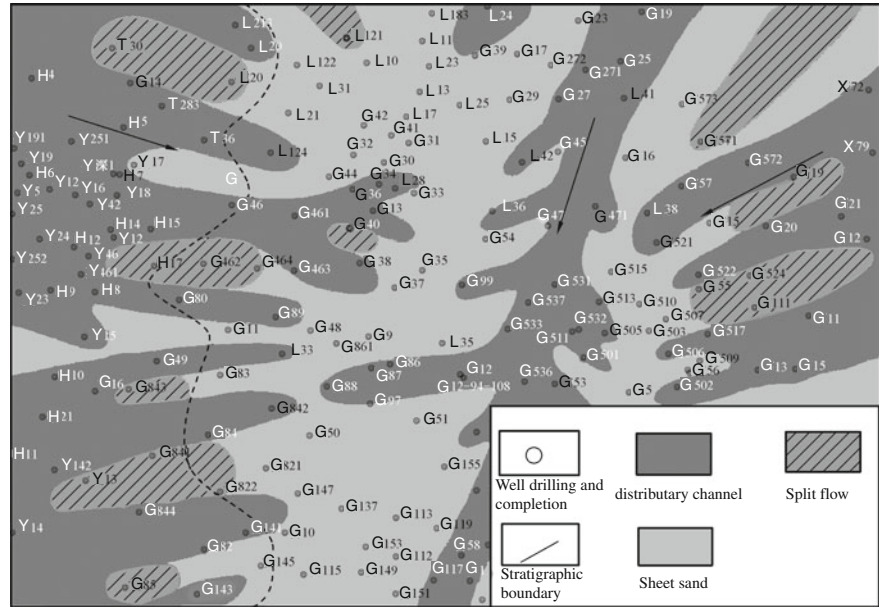


Fig. 2.2 A schematic diagram of reservoir provenance and deposition direction

2.1.2 Principal Permeability Direction

The main permeability direction of the reservoir is determined by provenance direction and deposition direction. Interlayer heterogeneity is a general characterization of the reservoir physical property variation in sand–shale interaction oil-bearing series. The impact on reservoir development is primarily the degree of heterogeneity of different oil layer permeability, namely interlayer permeability heterogeneity. Due to the characteristics, most of the layers are thin and the oil layer group is often taken as a development unit in China's continental reservoirs. In the oil layer groups, one well pattern is often used, generally with the method of multilayer commingled injection-production. Due to the interlayer heterogeneity of permeability, the permeability difference between the main layers and non-main layers can be dozens of or even hundreds of times. There is a big difference between oil layers in water absorption capacity and the advancement velocity of injection water. In the water injection development process, the difference mainly lies in the fact that water injection onrushes through a single layer, the main layer is first watered, the first effective zone is first flooded, and then significant interference occurs between layers. As a result, non-main layers are essentially not used or little used and a large quantity of remaining oil is left behind, seriously affecting the increase of ultimate recovery of the reservoir.

Intraformational heterogeneity refers to the vertical variation of reservoir properties in a single sand layer, including the difference degree of intraformational vertical permeability, the location of the highest permeability section, intraformational granularity rhythm, and distribution of the discontinuous thin interbed. Intraformational heterogeneity is a key factor in the direct control and influence of the infusion's swept volume and distribution of remaining oil in oil layers and is one of the important geological conditions that influence the ultimate recovery.

The heterogeneity of China's continental reservoirs is greatly influenced by sedimentary micro-facies and diagenesis, and even in single sand layers, the permeability variation is great. According to the statistics, fluvial and deltaic reservoirs are the main carriers of oil resources, accounting for 42.6 and 30.0 %, respectively, of China's total developed reserves. The intraformational heterogeneity of these two types is very strong, and the heterogeneity of other types such as the fan delta and alluvial fan is even stronger. From the perspective of impact of water flooding development, intraformational heterogeneity boils down to the intraformational permeability rhythm and the distribution of muddy intercalation. Permeability rhythm refers to the vertical variation degree of permeability in a single sand layer. The greatest impact of areal heterogeneity on water flooding includes connectivity of sand bodies and permeability's non-uniformity. They directly influence the swept area and sweep efficiency of injected water, thereby controlling the distribution of residual oil on the plane. Connectivity rate between injection wells and production wells is an important factor influencing water flooding effect. Regarding a certain injection-production well pattern, the higher the reservoir connectivity rate, the more reserves of water flooding control, the better effect of water flooding and the

less residual oil content. The areal heterogeneity of permeability directly controls the advancing direction of the injected water and oil displacement efficiency. During water flooding, injected water forms fingering along the formation of high permeability, resulting in very serious washing of highly permeable zones and smaller sweep degree in low-permeability zones. This uneven phenomenon in water flooding leads to uneven distribution of the remaining oil on the plane. Concerning river channel reservoir sand bodies, their permeability changes from high in the middle to low along the wings, i.e., the permeability is the biggest in the direction of the main river channel and the smallest on the both sides. It is these characteristics that determine the fact that the injected water onrushes along the high-permeability zones in the process of water injection development and it is difficult for the injected water to reach low-permeability zones on the both sides, which become the main distribution areas of remaining oil on the plane. Various types of reservoir direction can be described by permeability anisotropy quantitatively. Therefore, the study of the direction of reservoir is actually the study of heterogeneity of reservoir permeability.

The main permeability direction refers to the direction of maximum permeability. As for the continental deposit, reservoir plane permeability in any direction at any point is different from others, but there is a maximum direction, as shown in $K_{\max}$ in Fig. 2.3. The main permeability direction of the reservoir refers to the connected main permeability directions of a continuous reservoir, or the vector sum of a set of main permeability directions and the newly formed direction in the reservoir, as shown in Fig. 2.4. The main permeability direction is formed by the deposition process. A large reservoir with oil layers widely distributed on the plane can be divided into zones with different deposition characteristics. The main permeability direction of the main layers has regional features, i.e., the direction is altered when it reaches a different local area. Besides, oil layers on different planes have different main permeability directions because of the longitudinal sedimentary evolution. All these factors lead to the diversity of the main permeability direction. In any case, the main reservoir permeability direction on the plane determines the water flow direction in water flooding. In a normal pressure system, breakthrough happens first along the main permeability direction.

Determining the main permeability direction of the reservoir is very important for water flooding in the oilfield because it determines the main factors which

Fig. 2.3 Schematic of permeability at any point

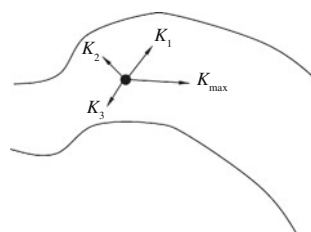
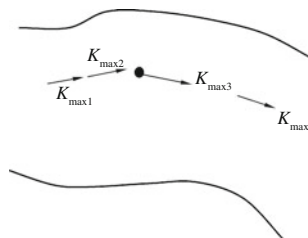


Fig. 2.4 Schematic of the main permeability direction



influence the development effects such as the design of the injection-production well pattern and the direction of water flooding.

2.1.3 Principal Stress Direction and Fracture

The force which is applied to an object from the exterior is called external force, and internal force is the interaction force between parts in the interior of the same object. The strength of the internal force is expressed as stress, which is the internal force per unit area. When an external force acts on an object, an internal force is generated to contend against the external force inside the object. Geologically, pressure stress is marked as positive and tensile stress as negative. Objects may be affected by force from one direction or multiple directions. The analysis of the force state of a certain point within an object is always related to the stress components of the point on the cross section in a certain direction. When there is only normal stress and no shear stress on the section, the normal stress on the section is called principal stress.

The direction of the horizontal principal stress plays an important role in well pattern design of oilfield development, especially in low-permeability oilfields. Usually, low-permeability reservoirs and tight oil and gas reservoirs have to be fractured before production. The direction of hydraulically created fractures is directly related to the direction of principal stress. Under normal circumstances, the fractured cracks extend in the direction of the principal stress. Of course, they may shift their directions in the process of fracturing, but ultimately they extend in the direction of the principal stress. In order to avoid sudden water flooding and improve water flooding efficiency, the development well pattern of the low-permeability oilfield must be compatible with the direction of the horizontal principal stress, for in situ stress direction is the main basis of development well pattern deployment in low-permeability oilfields. The direction of principal stress influences artificial fractures. In fact, the distribution of natural fractures has a close relationship with the direction of the principal stress, which basically determines the distribution characteristics of main fractures.

Formed by tectonic deformation, and physical and chemical diagenesis, cracks or fractures are macro discontinuity that naturally exists in rocks. They can not only

greatly improve the reservoir space of oil-and-gas reservoirs, but also serve as the pore fluid seepage channel to connect invalid pores. They can greatly improve the seepage ability and even control the formation and distribution of oil-and-gas reservoirs. Fractured reservoirs in China have the great potential of increasing reserves. Nevertheless, the complexity of reservoir fracture formation, the diversity of control and influence factors, the random distribution of high heterogeneity during the process of formation and development, etc., increase the difficulty of studying fractured reservoirs to some extent. The combination of geological and geophysical methods provides a new thought for detecting reservoir fractures. Cracks may be formed by many factors, such as underwater landslides, differential compaction, surface weathering joints, and dissolution. Some cracks such as beddings are formed through sedimentary deposition and diagenesis. In addition to natural causes, there are cracks in the reservoir caused by human factors, of which joints have the greatest impact on the heterogeneity of oilfields.

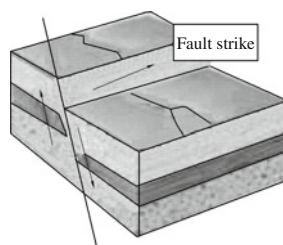
As for fractured reservoirs, distribution characteristics and direction of cracks have a significant impact on the deployment of the well pattern, as well as the direction and effectiveness of water flooding. In order to avoid rapid and sudden water flooding, the distribution law and direction of cracks must be taken into account in the design of well array and injection direction; that is to say, the production wells and injection wells cannot be located on the same line along which the cracks extend. The distribution of cracks must be carefully considered in well pattern deployment for the oilfield in which uniform fracturing production is implemented.

The formation and strike of cracks are influenced by many geological factors. There are a variety of means and methods for the analysis of the laws of reservoir fractures, as shown in Fig. 2.5. It is a schematic diagram of the distribution of cracks in Wen Block 13 of Zhongyuan Oilfield. The fracture distribution looks relatively irregular, but a careful analysis reveals that the main fractures extend basically in the same direction, NE 30°. Attention is also paid to the direction of main fractures in the development and deployment of the well pattern in oilfields.

2.1.4 Fault Strike and Structural Dip

The rupture of rock formation or rock mass occurs under the pressure of geological tectonic movements. If apparent relative displacement occurs between the two rock masses on the both sides of the fracture surface, such a configuration is called a fault.

There are many types of fault, which exist in all shapes and sizes and differ greatly in size. Large faults extend up to several hundreds to more than one thousand kilometers, and small faults can be found in rock samples. The dissection depths of faults are also different. Some can cut through the crust and extend to the mantle. Faults destroy the continuity and integrity of rock and have an important influence on its stability, permeability, earthquake activity, and regional stability.

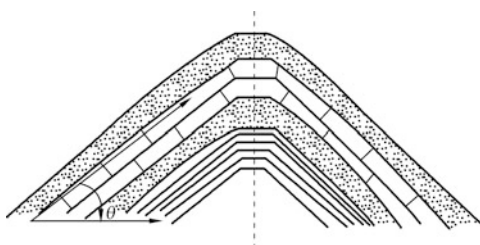
Fig. 2.6 Fault strike

No matter what the situation is, the distribution and properties of faults must be taken into account in the process of oilfield development and the actual deployment of the well pattern, because they influence the continuity of reservoir strata and the permeability of the reservoirs on the both sides of the faults. Oil wells cannot be deployed too close to a fault. When horizontal wells and vertical wells are drilled, the production section cannot go into production if it crosses a fault. The extension direction of horizontal wells is generally parallel to a fault.

Structural characteristics of different reservoirs can be quite different because of their different geneses, mainly including the horizontal structure, monoclinic structure, anticline structure, and fracture structure. Structural dip is the angle between the horizontal line and the tendency of the reservoir, as shown in Fig. 2.7. Thus, the reservoir with a structural dip will have a certain slope, and the oil–water wells in different parts will have a height difference. In the actual process of water flooding in a large-angle reservoir, water will flow to the low part of the reservoir due to oil–water gravitational differentiation, which greatly influences the water flooding efficiency. Therefore, the influence of structural dip on water injection should be taken into consideration when designing the well pattern deployment. Besides, a reasonable design should be made of the well working system and production difference pressure. The difference pressure between injection wells and production wells should be the difference pressure between the injection wells and the high parts of the oil wells. It should be larger than the pressure difference between the injection wells and the low parts of production wells.

2.1.5 Direction of Edge and Bottom Water Invasion

Because the wells in edge and bottom water reservoirs will be drowned out due to the edge and bottom water intrusion, their production will rapidly decrease and their

Fig. 2.7 Structural dip

waterout will rise sharply when the oil well is watered out and some even produce water only, which greatly affects the development efficiency. During the development process, flooded wells and the floodout should be avoided or delayed. This requires that the direction and mode of the edge and bottom water onrush be clarified.

The direction of edge water invasion refers to the direction in which the edge and bottom water seepage advances fastest to the bottom of the production well. Regarding the bottom water reservoir, the following factors will influence the speed and mode of breakthrough: the connectivity between the edge and bottom water zone and the oil province, water body size, reservoir permeability, reservoir heterogeneity, fluid properties, etc. When the reservoir and the water are not connected due to impermeable barriers or sandwiches, there is no need to consider the influence of edge and bottom water; otherwise, the water invasion direction must be analyzed clearly. Under normal circumstances, the edge water invades the reservoir along the edge of the water body, but because of the permeability difference or directivity, there may appear banded or single-direction intrusion, as shown in Fig. 2.8. The bottom water may bypass the interlayers and cause plane onrush phenomenon (Fig. 2.9). Therefore, it is of specific referential significance to find out the direction of edge water intrusion in deploying the production well pattern and applying a reasonable way to avoid the water. Furthermore, blocking high-permeability channels or diverting the water flow may be favorable to have a reasonable development of edge water reservoirs.

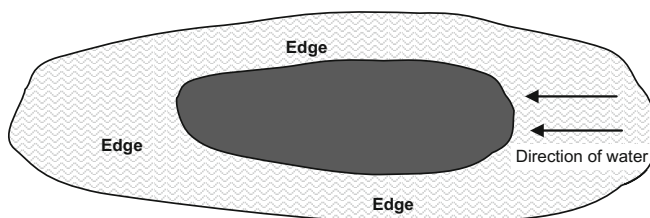


Fig. 2.8 Oriented edge water invasion

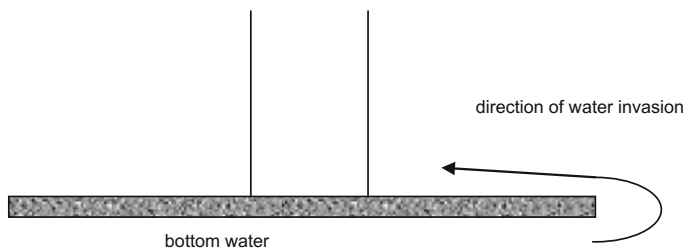


Fig. 2.9 Bottom water invasion bypasses the interlayer

2.2 Permeability Distribution Law

Permeability is an important parameter to control reservoir performance. If the permeability values of each position are the same, it is said to be homogeneous; if at a certain location, the permeability in any direction is the same, it is isotropic. But in fact, almost no homogeneous permeability or isotropic reservoirs exist. Research and production practice show that the value of permeability has distinct directivity, and thus, permeability is a vector. Directional differences in permeability will directly influence the technical design of a variety of development measures, such as the well pattern arrangement and the value of well spacing and artificial fracturing.

2.2.1 *Cause for Permeability Anisotropy*

The fact that permeability shows its directivity (vector property) is due to geological genesis. The studies of F.J. Pettijohn et al. show that the directivity of rock permeability can be attributed to the arrangement direction of sand. In the deposition process, the long axis of sand is mainly parallel to the flow direction and forms a 15° – 18° superimposed intersection with the deposition interface in the counter-current direction, thereby generating a directional difference of permeability. In addition, R.F. Mast and other researchers also believe that the arrangement orientation of the rock matrix and the filling mode are closely linked to the direction of permeability, and permeability increases significantly in the direction parallel to the sand transport direction. These findings have been confirmed in practice. Pryor's study reveals that in alluvial sandstones, the orientation of maximum permeability direction coincides with the river axis, and the maximum permeability direction of shoreface sandstones and the beach sand is parallel to the direction of tidal scour. Banilo Bandiziol and other researchers also find that all the maximum permeability directions that are measured by well test analysis and core measurement are the same as the paleocurrent direction. After sand deposits in the fluid directional flow, the water continues to flow in permeable sand. In the seepage channel parallel to the direction of the flow channel, the flow rate is high, and the pore channels on either side of the mainstream line become a retention area. Plenty of fine particles deposit in the pores in the retention area because of the low flow rate, which inevitably results in higher permeability in the flow direction than that in the other directions. Because crack extension has a clear direction, cracks are also another important factor that causes vector features of rock permeability.

2.2.2 *Distribution of Permeability*

Almost all of the reservoirs have multiple zones, so not only the permeability values between small layers are quite different, but also the horizontal and vertical

permeability values in the same small layer differ greatly. To solve this problem, one of the easiest ways that come into our minds is to simplify the longitudinal non-homogeneous layers into a series of homogeneous layers which overlap each other but do not communicate with each other; that is to say, the performance of each homogenous layer added is that of the full layer. Such a simplification totally ignores the horizontal permeability difference in the same layer, which is called stream tube method or stream sheet method (also often called Stiles method in the USA). Of course, this is just a kind of approximate method and a rather conservative approximation method which can be proved later.

There are low-permeability segments in the high-permeability layer and high-permeability segments in the low-permeability layer. Permeability values vary within a wide range. In a reservoir, different permeability values take up a certain proportion in a certain interval. For example, in the low-permeability layer, the proportion of high-permeability segments is small, and in the high-permeability layer, the proportion of low-permeability segments is small. Permeability values in different facies belts are not the same, and those in the same facies belt are still very different. The key is to find out the permeability distribution, which is usually expressed with a cumulative permeability distribution curve. As long as we know the percentage of permeability in a certain interval, we can find out the distribution of permeability. The proportions of permeability in different intervals are taken as distribution density of permeability.

People can never accurately measure the permeability value at each point in a reservoir, so it is impossible to find out the absolutely precise permeability distribution. But through the permeability data obtained in a certain number of coring wells, we can judge permeability distribution of a reservoir with a certain confidence, which is called confidence coefficient.

Common permeability distribution density is shown in Table 2.1, in which $\Gamma(x)$ is called gamma function and can be expressed as:

Table 2.1 Common distribution density of permeability

	Distribution	Average value	Standard deviation	Variable coefficient
Lognormal	$\frac{1}{\sqrt{2\pi}\sigma x} e^{-\frac{(\ln x - \mu)^2}{2\sigma^2}} (x > 0)$	$e^{\mu + \frac{\sigma^2}{2}}$	$(e^{\sigma^2} - 1)^{\frac{1}{2}} \cdot e^{\mu + \frac{\sigma^2}{2}}$	$(e^{\sigma^2} - 1)^{\frac{1}{2}}$
Maxwell (1)	$\frac{2}{\sqrt{\pi}} e^{-\frac{(x-a)^2}{x_0^2}} \cdot \frac{(x-a)^2}{x_0^2} \cdot \frac{1}{x_0} (x > a)$	$\frac{3}{2}x_0 + \mu$	$\sqrt{1.5}x_0$	$\frac{\sqrt{1.5}x_0}{1.5x_0 + \mu}$
Maxwell (2)	$\frac{2}{\sqrt{\pi}} e^{-\frac{(x-a)^2}{x_0^2}} \sqrt{\frac{\pi-a}{x_0}} \cdot \frac{1}{x_0} (x > a)$	$\frac{2}{\sqrt{\pi}}x_0 + \mu$	$x_0 \sqrt{1.5 - \frac{4}{\pi}} = 0.4762x_0$	$\frac{0.4762x_0}{\frac{2}{\sqrt{\pi}}x_0 + \mu}$
$\Gamma(x)$ Distribution	$\frac{\beta^\alpha}{\Gamma(\alpha)} (x - c)^{\alpha-1} e^{-\beta(x-c)} (x > c)$	$\frac{\alpha}{\beta} + C$	$\frac{\sqrt{\alpha}}{\beta}$	$\frac{\frac{\sqrt{\alpha}}{\beta}}{\frac{\alpha}{\beta} + C}$
$\Gamma(x^2)$ Distribution	$\frac{2}{\Gamma(\frac{r}{2})} \left(\frac{x}{x_0}\right)^{r-1} e^{-\left(\frac{x}{x_0}\right)^2} \cdot \frac{1}{x_0} (x > 0)$	$\frac{\Gamma(\frac{r+1}{2})}{\Gamma(\frac{r}{2})} x_0$	$x_0 \cdot \sqrt{\frac{r}{2} - \left[\frac{\Gamma(\frac{r+1}{2})}{\Gamma(\frac{r}{2})}\right]^2}$	

$$\Gamma(x) = \int_0^{\infty} e^{-t} t^{x-1} dt \quad (2.1)$$

The function values corresponding to the independent variables can be consulted in a ready function table.

Ways for finding theoretical distribution of permeability are as follows.

The first is the probability paper method. If the data (sample values) are marked on the lognormal probability paper by means of point tracing, all the points are substantially on a straight line, which can be considered permeability lognormal distribution. The abscissa of the lognormal probability paper is scaled by natural logarithm, and the ordinate is scaled by the normal scale.

The probability graph paper of $\Gamma(x)$ and $\Gamma(x^2)$ can also be printed if needed.

The second method is curve fitting. The data points obtained through the analysis of the sample are marked on a transparent chart with the same as theoretical distribution coordinates and are coincided with a theoretical distribution curve to see what theoretical distribution curve they are in line with. Permeability is considered to obey theoretical distribution represented by that curve.

The third method is cut and trial, which is widely used in distribution density function:

$$f(x) = \frac{n}{\Gamma(\frac{r}{2})} e^{-\left(\frac{x}{x_1}\right)^n} \cdot \left(\frac{x}{x_1}\right)^{\frac{r-1}{2}} \cdot \frac{1}{x_1} \quad (2.2)$$

The corresponding distribution function is:

$$F(x) = \Gamma\left[\frac{r}{2}, \left(\frac{x}{x_1}\right)^n\right] / \Gamma\left(\frac{r}{2}\right) \quad (2.3)$$

Calculation steps are as follows:

- Find the distribution of samples. Divide the permeability values into 20–30 intervals. Count the number of samples and the cumulative number of samples that fall into each section and calculate the percentage of the cumulative samples.
- The assumed theoretical distribution is consistent with the empirical distribution of samples. Under this condition, assume a series of r values and find out a series of corresponding $\left(\frac{x}{x_1}\right)^n$ values from the corresponding theory.
- With the permeability value of each sample interval as abscissa and the corresponding different $\left(\frac{x}{x_1}\right)^n$ of r values as ordinate, mark the values on the double-logarithmic graph and link up the points corresponding to the same r value. The line that is closer to a straight line is theoretical distribution, as in Fig. 2.10.

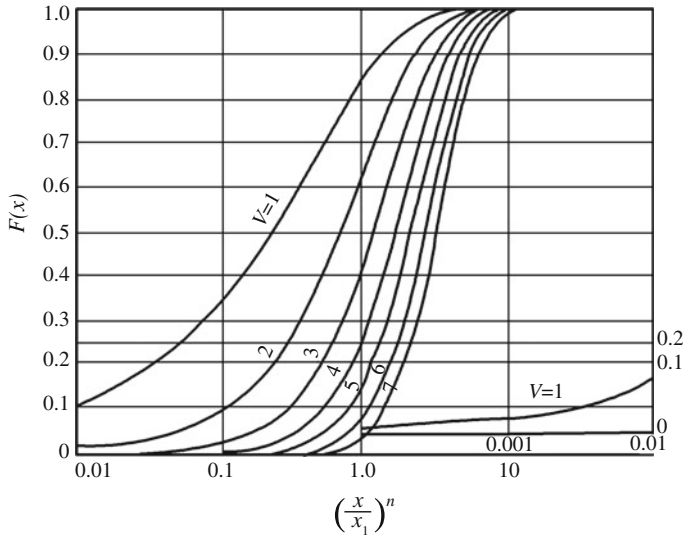


Fig. 2.10 The relationship of theoretical distribution and $(x/x_1)^n$ relationship

- d. The slope of that straight line on the double-logarithmic coordinate is the required distribution parameter n . The intercept on the vertical axis is $-n \lg x_1$, according to which another parameter x_1 can be obtained.
- e. Find out the difference between the theoretical distribution value corresponding to the double-logarithmic straight line and the distribution values of sample empirical (absolute value) as well as the maximum difference D_N between theoretical distribution and the sample distribution. If the confidence coefficient is 0.95, theoretical distribution found is accepted when $D_N \sqrt{N} < 1.36$ (N is the sample size).
- f. If r , n , and x_1 are known, the parameters of theoretical distribution can be calculated with the following formulae:

Mean μ :

$$\mu = \frac{\Gamma(\frac{r}{2} + \frac{1}{n})}{\Gamma(\frac{r}{2})} x_1 \quad (2.4)$$

Variance σ^2 :

$$\sigma^2 = \frac{\Gamma(\frac{r}{2} + \frac{2}{n}) x_1^2}{\Gamma(\frac{r}{2})} - \mu^2 \quad (2.5)$$

Example 2.1 If the core analysis data of 10 wells (A–J) are available (10 samples from each well) and a total of 100 permeability values shown in Table 2.2, find the distribution of its permeability.

Table 2.2 Permeability data table

	A	B	C	D	E	F	G	H	I	J
2228.0	2.9	7.4	30.4	3.8	8.6	14.5	39.9	2.3	12.0	29.0
2228.3	11.3	1.7	17.6	24.6	5.5	5.3	4.8	3.0	0.6	99.0
2228.7	2.1	21.2	4.4	2.4	5.0	1.0	3.9	8.4	8.9	7.6
2229.0	167.0	1.2	2.6	22.0	11.7	6.7	74.0	25.5	1.5	5.9
2229.3	3.6	920.0	37.0	10.4	16.5	11.0	120.0	4.1	3.5	33.5
2229.7	19.5	26.6	7.8	32.0	10.7	10.0	19.0	12.4	3.3	6.5
2230.0	6.9	3.2	13.1	41.8	9.4	12.9	55.2	2.0	5.2	2.7
2230.3	50.4	35.2	0.8	18.4	20.1	27.8	22.7	47.4	4.3	66.0
2230.6	16.0	71.5	1.8	14.0	84.0	15.0	6.0	6.3	44.5	5.7
2231.0	23.5	13.5	1.5	17.0	9.8	8.1	4.6	4.6	9.1	60.0

Unit $10^{-3} \mu\text{m}^2$

Table 2.3 Permeability grouping statistics

Permeability intervals	>30	28 30	26 28	24 26	22 24	20 22	18 20	16 18	14 16	12 14	10 12	8 10	6 8	4 6	2 4	0 2
Number of samples	20	1	2	2	2	3	3	3	4	5	6	8	7	12	13	9
Cumulative number of samples	20	21	23	25	27	30	33	36	40	45	51	59	66	78	91	100
Cumulative percentage (%)	20	21	23	25	27	30	33	36	40	45	51	59	66	78	91	100

Unit $10^{-3} \mu\text{m}^2$

Taking no account of the depth, divide the permeability into 15–20 levels in descending order, count the number of samples in each group and the accumulative samples, and calculate the cumulative percentage (see Table 2.3).

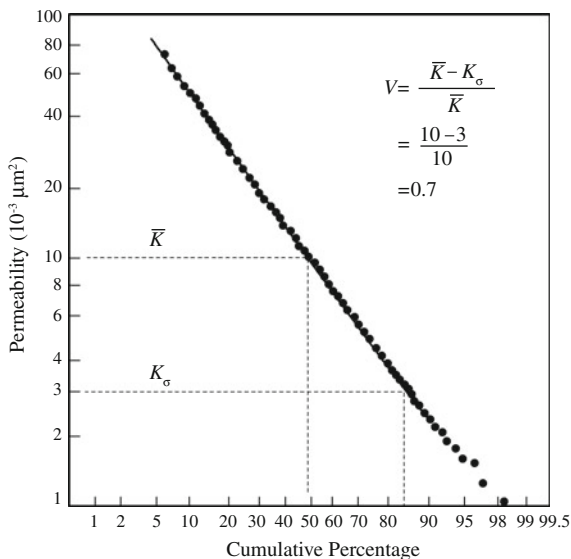
Then, with the cumulative percentage as abscissa and the lower limiting value of each group ordinate, trace the points on the lognormal probability paper to get an approximate straight line, but the more concentrated ends of these lines are a little far from the straight-line segment (Fig. 2.11).

For normal distribution, in the interval of random variable $(\mu - \sigma, \mu + \sigma)$ with the mean μ and variance σ^2 , the probability is 0.682; in the interval of $(\mu, \mu + \sigma)$, the probability is 0.341. So when the cumulative percentage is 84.1 %, the difference between the permeability and permeability mean values is just a standard deviation σ and the variation coefficient is V:

$$V = \frac{\sigma}{\mu}$$

(2.6)

Fig. 2.11 Lognormal distribution



For lognormal distribution, the variation coefficient is:

$$V = \frac{\lg K_{\sigma} - \lg \bar{K}}{\lg \bar{K}} \quad (2.7)$$

In this example, $K_{\sigma} = 3$ (the corresponding accumulative percentage is permeability value 84.1 %, $10^{-3} \mu\text{m}^2$),

$\bar{K} = 10$, $10^{-3} \mu\text{m}^2$ so $V = 0.7$ (the mean of permeability distribution).

But in reality, the following formula is used instead of corresponding logarithmic expression.

$$V = \frac{K_{\sigma} - \bar{K}}{\bar{K}} \quad (2.8)$$

In this example, $K_{\sigma} = 3$, $\bar{K} = 10$, so $V = 0.7$.

The maximum difference between theoretical distribution and the sample distribution occurs at the permeability of $0.01 \times 10^{-3} \mu\text{m}^2$. The difference is 0.035 and then $0.035 \times \sqrt{100} = 0.35 < 1.36$.

So in the premise of confidence level of 0.95, the assumption of lognormal distribution is accepted.

2.2.3 Description Method of Permeability Vector

Geological parameters of the reservoir tend to have strong directivity, which is called geological vector. Due to the anisotropy of geological vector of the reservoir,

the injection fluid preferably advances along the direction of high permeability in water flooding process and breakthrough occurs in the production wells in different directions at different times, which results in uneven displacement process, thus affecting the development efficiency of the reservoir.

Reservoir geological vector includes very rich content. Only permeability vector's influence on the development pattern is discussed here. Most of the reservoir rocks fall into the category of sedimentary rocks. The rock skeleton particles are not in the spherical shape due to the effect of long-time erosion and abrasion of water, but irregular ellipsoid shape. In the deposition process, ellipsoid clastic particles have the tendency of orientational alignment with the transport medium and their long axes are generally in the same direction as the water flow, while the short axes are perpendicular to the flow direction. The compaction in the process of diagenetic also strengthens the directional arrangement of skeleton particles.

Oriental alignment of framework grains endows the permeability of clastic rocks with directivity, and thus, it has the nature of vector. There is more than one permeability value at a certain point in the formations, but countless, each being a vector. In general, the permeability parallel to the direction of paleocurrent is greater than that perpendicular to the direction of paleocurrent; the horizontal permeability is greater than the vertical permeability. In order to clearly express the status of permeability of reservoir rock, the form of tensor is usually used, namely

$$K = \begin{bmatrix} K_x & 0 & 0 \\ 0 & K_y & 0 \\ 0 & 0 & K_z \end{bmatrix} \quad (2.9)$$

where K_x , K_y , and K_z are main permeability values along the direction x , y , and z , $10^{-3} \mu\text{m}^2$; if formation $K_x = K_y = K_z$, it is known as isotropic medium; if $K_x \neq K_y \neq K_z$, it becomes anisotropic medium. Almost all of the clastic reservoirs are characterized by anisotropic medium, and isotropic medium is just a particular case of anisotropic medium.

Large opening secondary cracks have developed some reservoirs. Because the cracks are produced under the action of tectonic stress and they are in the same direction as the change direction of tectonic stress, the existence of cracks exacerbates the anisotropy of the formation. In general, the permeability parallel to the direction of the fractures is greater than that of vertical fractures. The direction of fractures is usually the direction of the biggest formation permeability.

The permeability corresponding to the two-dimensional anisotropic formation can be expressed as:

$$K = \begin{bmatrix} K_x & 0 \\ 0 & K_y \end{bmatrix} \quad (2.10)$$

where K is the permeability tensor; K_x and K_y are the principal permeability values along the direction of x and y , $10^{-3} \mu\text{m}^2$; when $K_x = K_y$, the formation is isotropic.

2.3 Test and Calculation Methods of Permeability Direction

The permeability of the rock is marked by directivity, and therefore, permeability is a vector. Its accurate description plays an important role in the determination of water drive direction and well pattern arrangement, so reservoir engineers have attached importance to it in the development practice. In this section, several methods for analyzing the direction of the permeability are presented.

2.3.1 *Calculation of Permeability Vector*

1. Vector calculation of permeability

Permeability refers to the permeability of the seepage passages, and it could not go without them. With a clear physical meaning, permeability cannot be synthesized and decomposed arbitrarily like free vector in mathematics. The permeability vectors in two different directions cannot be synthesized as the permeability in the corresponding direction, nor can the projection of permeability vector in a certain direction be regarded as the permeability value in this direction.

When the permeability in two different seepage passages were synthesized, according to the synthetic characteristics of the vector, the permeability vectors in two different directions could be synthesized as the permeability in the direction of the resultant vector. However, this cognition is wrong through analysis. The reason is the neglect of the conditions for vectors to be synthesized. Vectors can be divided into two categories: free vector and non-free vector, and different vector types need different synthetic conditions. The free vector has nothing to do with the spatial position. The vectors in mathematics are free vectors, and any two free vectors can be synthesized. The non-free vector is concerned with the spatial position. The vectors in physics are usually non-free vectors, such as velocity and moment of force. Regarding a non-free vector with physical meaning, only the two vectors belonging to the same kind can be synthesized. On the contrary, the two vectors belonging to different kinds cannot be synthesized. Permeability refers to the permeability in the seepage passages (or seepage paths), and it could not go without them. Therefore, it is the same as the synthesis of the particle velocity, and permeability vectors in the two different percolation channels cannot be synthesized to find the permeability vector in another percolation channel. The permeability vectors in different directions cannot be synthesized, because they belong to different seepage paths. It is the same problem that a component in a direction of permeability vector in a seepage passage is regarded as the permeability vector of the seepage passage in this direction.

2. Quantitative calculation model of vector permeability

The permeability value of rock cannot be obtained by the synthesis or decomposition of vector. According to the principle for equivalent displacement, vector permeability can be deduced and established, namely the calculation model of anisotropic permeability. In the process of deduction, it is assumed that the permeability medium is orthotropic, that is, the x -axis and y -axis of the coordinate system are consistent with the direction of maximum and minimum permeabilities, respectively.

As shown in Fig. 2.12, ∇P_n shows the displacement pressure gradient in the n -direction, and A indicates the area of ∇P_n and the vertical flow cross section. The displacement of ∇P_n aimed at the fluid is the equivalent of the displacement function of x component ∇P_{nx} and y component ∇P_{ny} , which is called the equivalent displacement principle. If Q_x is used to express the flow rate of section A in the x -direction and Q_y the flow rate of section A in the y -direction, then according to the principle for equivalent displacement, the flow rate Q_n , which goes through seepage section A , is equal to the function:

$$Q_n = Q_x + Q_y \quad (2.11)$$

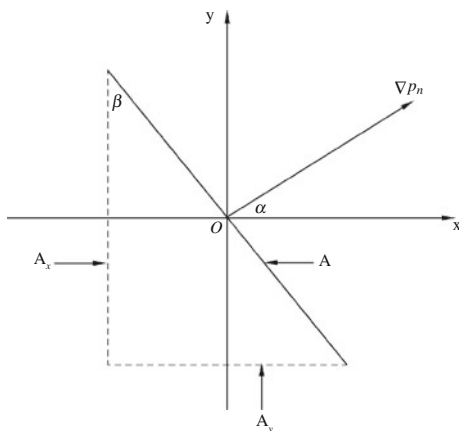
K_n is used to express the permeability in the n -direction, v_n the velocity of the fluid flow in the n -direction and μ the viscosity of the fluid. According to Darcy's law:

$$v_n = \frac{K_n}{\mu} \nabla P_n \quad (2.12)$$

So the flow rate that goes through section A is:

$$Q_n = Av_n = -A \frac{K_n}{\mu} \nabla P_n \quad (2.13)$$

Fig. 2.12 Deduction of calculation model of permeability



As shown in Fig. 2.11, A_x is used to express the effective flow area of cross section A in the x -direction (i.e., the seepage area vertical to the x -direction), and α is used to express the azimuth in the direction of the n . Since both sides of the β angle are perpendicular to the sides of α angle, $\beta = \alpha$, so

$$A_x = A \cos \beta = A \cos \alpha \quad (2.14)$$

Similarly, the effective flow area of the cross section A in the y -direction (i.e., the seepage area vertical to y -direction) is:

$$A_y = A \sin \beta = A \sin \alpha \quad (2.15)$$

The component of ∇P_n in the x -direction is:

$$\nabla P_{nx} = \nabla P_n \cos \alpha \quad (2.16)$$

Under the effect of ∇P_n , the flow velocity of the fluid that goes through cross section A in the x -direction is:

$$v_n = \frac{-K_x}{\mu} \nabla P_{nx} \quad (2.17)$$

Therefore, the flow rate of the fluid that goes through cross section A in the x -direction under the effect of ∇P_n is:

$$Q_x = v_x A_x \quad (2.18)$$

So,

$$Q_x = -A \frac{K_x}{\mu} \nabla P_n \cos^2 \alpha \quad (2.19)$$

The same can be obtained:

$$Q_y = -A \frac{K_y}{\mu} \nabla P_n \sin^2 \alpha \quad (2.20)$$

Then,

$$-A \frac{K_n}{\mu} \nabla P_n = -A \frac{K_x}{\mu} \nabla P_n \cos^2 \alpha = -A \frac{K_y}{\mu} \nabla P_n \sin^2 \alpha \quad (2.21)$$

Both of the above equations are divided by $-A \frac{1}{\mu} \nabla P_n$.

Then,

$$K_n = K_x \cos^2 \alpha + K_y \sin^2 \alpha \quad (2.22)$$

The above equation is the quantitative calculation model of vector permeability (i.e., anisotropic permeability). When the permeability of the x -direction and y -direction is known, the model can be used to calculate the rock permeability vector K_n corresponding to any direction n on the plane (the azimuth being α). From the above-mentioned, the x -direction and y -direction represent the maximum or minimum permeability of rock, respectively, and the maximum and minimum permeability of rock and their directions can be obtained by an experiment.

2.3.2 Analysis of Directivity of Reservoir Permeability with Variogram

In recent years, the function of the variogram has played a very important role in the study of reservoir heterogeneity. Because the variability of reservoir parameters in each direction is different from each other, the anisotropic structure can be reflected by the value of the variogram in each direction. Through the study of the areal heterogeneity of the reservoir with all the structural information provided by the variogram, it can be concluded that heterogeneity is weak along the direction parallel to the provenance direction, and it is strong in the direction vertical to the provenance direction.

Variogram is a basic tool for geostatistics, which can reflect the spatial variation of regionalized variables, especially the structural characteristics of regionalized variables through randomness. Variogram contains a lot of geological information, so variation function can be interpreted in terms of geological theory by calculating the experimental variation function in accordance with regionalized variables and fitting a model of theoretical variation function.

Variable difference function refers to the half of the increment variance of the regionalized variable $Z(X)$ at the two points, X and $X + h$, that is, the half of the increment quadratic mean of the regional variable at any two points, the distance between which is h , namely,

$$r(X, h) = \frac{1}{2} \sum [Z(X) - Z(X + h)]^2 \quad (2.23)$$

The calculation formula for the experimental variation function is:

$$r^*(h) = \frac{1}{2N(h)} \sum_{i=1}^{N(h)} [Z(X_i) - Z(X + h)]^2 \quad (2.24)$$

In the equation,

x_i	is the coordinates of the i th observation point;
$Z(x_i), Z(x_i + h)$	are the observation values at x_i and $x_i + h$, respectively;
H	is the distance between two observation points;
$N(h)$	is the number of data pairs, the distance of which is h ;
$r^*(h)$	is the experimental variation function value.

According to the reservoir known parameter value of the wells, a set of different experimental variogram values can be obtained according to different hi ($i = 1, 2, \dots, n$) values in the same direction. The set of points $[h, r^*(h)]$ obtained with h as the horizontal coordinates and $r^*(h)$ as the vertical coordinates is called variation diagram. There are three major characteristic values α , c , and c_0 , which is obtained through spherical theoretical model that fits with the experimental variation function. The general formula of the spherical model is (2.16):

$$r(h) = \begin{cases} 0, & h = 0 \\ c_0 + c \left(\frac{3h}{2a} - \frac{h^3}{2a^3} \right), & 0 < h \leq a \\ c_0 + c, & (h) > a \end{cases} \quad (2.25)$$

In the equation,

A	is codomain, m;
C	is sagitta, m;
c_0	is nugget constant;
$(c + c_0)$	is sill value.

The characteristic values of the variation function reflect the spatial variation of reservoir parameters. The range a refers to the value of the variogram that no longer increases and keeps stable in the vicinity of a limit value when the distance exceeds a certain range. This range is called codomain. The limit value is known as the sill value ($c + c_0$). Nugget constant refers to the value of the variogram at the origin. Variable range α reflects the relevant scope of the regional variable. Within the scope of codomain, the regionalized variables have spatial correlation, but they have no spatial correlation out of the scope of codomain. Variable range α can not only reflect the influence of the regional variables, but also directly reflect the change of the reservoir parameters along a certain direction. And the sill value can reflect the range of the change of reservoir parameters along a certain direction. Nugget constant is mainly caused by the measurement error and micro-mineralized structures.

Due to the variability difference of the reservoir parameters in each direction, the anisotropic structure can be reflected by calculating the variogram value in every direction, so all the structural information is provided by variation function, which can be used to analyze and understand geological problems. Besides, the variation function can be tested again in the perspective of geology, which indicates that it can meet the requirements of reservoir research and it is a good tool for studying reservoir heterogeneity.

The areal heterogeneity of the reservoir, that is, the anisotropy of the regional variables, is worked out by comparing, analyzing, and studying the variation diagram of the same parameter in different directions. The value of the range a in the variation diagram can reflect the pace of the change of the reservoir parameters along a certain direction. The bigger the value, the slower the change in the direction of the parameter and the weaker the anisotropy and the heterogeneity. On the contrary, the smaller the value, the faster the change of the parameter and the stronger the anisotropy and the heterogeneity. The sill value ($c + c_0$) can reflect the magnitude of the change of reservoir parameters in a certain direction. The larger the sill value, the larger the parameter variation range and the stronger the anisotropy. On the contrary, the smaller the value of the sill, the smaller the parameter variation and the weaker the anisotropy.

2.3.3 *TDS Technique for Determining the Anisotropy of Reservoir Plane Permeability*

In order to determine the reservoir plane anisotropy precisely and avoid the cumbersome pressure curve matching, an approach is proposed based on Tiab's direct calculation (TDS) technique to determine the maximum and minimum directional permeability, its azimuth angle, average plane permeability and the magnitude of permeability anisotropy. First, make the double-logarithmic curve chart of interference well testing pressure of and pressure derivative of the planar anisotropic reservoir. Second, find out the directional permeability of the perturbed well and observation well in accordance with the pressure of the curve intersection point, the pressure derivative, and the dimensionless time. Then, substitute the directional permeability into the quantitative calculation model of anisotropic permeability of the observation wells to find the solution.

TDS technique makes use of the data of the pressure and pressure derivative to make the double-logarithmic curve and makes a direct analysis of some important feature points and feature lines of the curve to avoid the cumbersome analysis of the plate fitting of the conventional well test curve and to have a direct access to the reservoir physical properties.

1. Determination of directional permeability in the anisotropic reservoir

As to the single-phase and slightly compressible flow in the anisotropic oil reservoirs with horizontally infinite size and equal thickness, the pressure diffusion equation is:

$$\frac{\partial^2 p}{\partial^2 r} + \frac{1}{r} \frac{\partial p}{\partial r} = \frac{\phi \mu C_r \partial p}{3.6 k \partial t} \quad (2.26)$$

and the definite condition of the formula (2.26) is:

$$\begin{cases} p|_{t=0} = p_i, p|_{r=\infty} = p_i \\ r \left(\frac{\partial p}{\partial r} \right) \Big|_{r=r_w} = 1.842 \times 10^{-3} \frac{q B_o \mu}{k h} \end{cases} \quad (2.27)$$

In the equation,

- P is the reservoir pressure at a point with a distance of r from the well at the t moment, MPa
 r is the distance of any point from the well in the oil reservoir, m
 t is the production time from the opening time, h
 $\bar{k}$ is the average plane permeability, μm^2
 ϕ is the reservoir porosity, dimensionless
 μ is the fluid viscosity, mPa s
 C_t is the comprehensive compressibility, MPa^{-1}
 h is the reservoir thickness, m
 r_w is the well radius, m
 Q is the surface flow rate of the well, m^3/d
 B_o is the oil volume factor, dimensionless.

Equation (2.1)'s dimensionless power integral expression of Eq. (2.26) under definite condition is:

$$P_D = -\frac{1}{2} E \left(\frac{-r_D^2}{4t_D} \right) \quad (2.28)$$

where the dimensionless pressure, time, and distance are defined as:

$$P_D = \frac{\bar{k} h}{1.842 \times 10^{-3} q B_o \mu} \Delta p \quad (2.29)$$

$$t_D = \frac{3.6 k_n t}{\phi \mu C_t r_w^2} \quad (2.30)$$

$$r_D = \frac{r}{r_w} \quad (2.31)$$

In the equation,

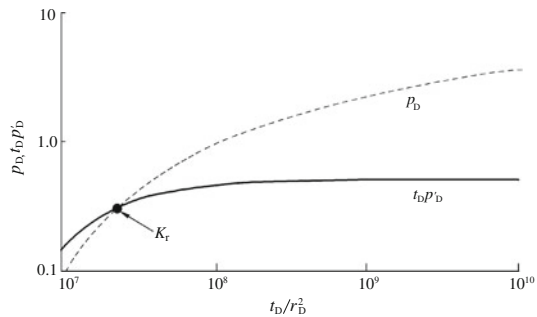
- ΔP is the drawdown pressure, MPa
 k_n is the directional permeability, μm^2 .

Dimensionless pressure derivative P'_D should meet the demand:

$$\frac{t_D}{r_D^2} P'_D = \frac{1}{2} \exp \left(\frac{-r_D^2}{4t_D} \right) \quad (2.32)$$

The dimensionless time, dimensionless pressure and dimensionless pressure derivative be drawn with logarithmic curve, as shown in Fig. 2.13.

Fig. 2.13 TDS method used to obtain the figure of directional permeability k_r



As shown in Fig. 2.13, the typical characteristics of TDS in the anisotropic reservoir are that double-logarithmic curves of pressure and pressure derivative intersect at one point. Find the pressure value at the point of intersection from the graph $(\Delta p)_{\text{node}(\Delta p)}$, the pressure derivative value $(t \Delta p')_{\text{node}}$, and the time value $(t_D / r_D^2)_{\text{node}}$, and the directional permeability k_n can be easily obtained, that is,

$$k_n = \frac{\phi \mu C_t r^2}{(t_D / r_D^2)_{\text{node}} t_{\text{node}}} \quad (2.33)$$

2. Determination of plane anisotropic permeability

Make interference well testing of the well pattern that consists of three production wells (observation wells) and an injection well (perturbed well). Take the perturbed well as the origin to create a rectangular coordinate system so as to determine the location of the wells and measure the azimuth angle β_i between the observation wells and the x -axis (i corresponds to the observation wells 1, 2, and 3). Assume the position of the semiaxis of the maximum and minimum permeabilities, respectively, in order to determine the maximum permeability azimuth angle and the azimuth angle between the observation wells and the azimuth angle θ_i of the maximum permeability semiaxis, with the counterclockwise direction as positive, as shown in Fig. 2.14.

Quantitative calculation model for directional permeability is:

$$\frac{1}{k_{ni}} = \frac{\cos^2 \theta_i}{k_{\max}} + \frac{\sin^2 \theta_i}{k_{\min}} \quad (2.34)$$

According to Fig. 2.14,

$$\theta_i = \beta_i - \alpha \quad (2.35)$$

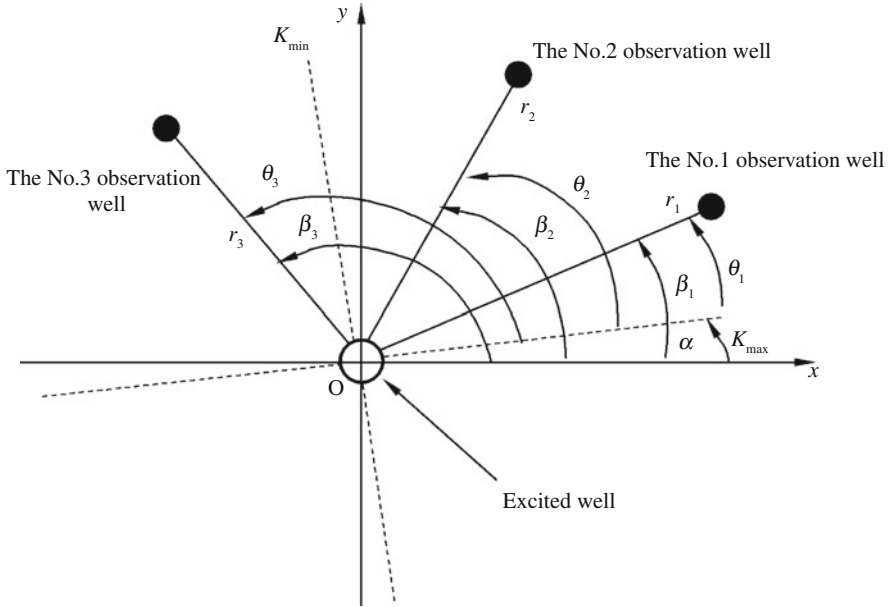


Fig. 2.14 Distribution of interference test wells

then,

$$\frac{1}{k_{ni}} = \frac{\cos^2(\beta_i - \alpha)}{k_{\max}} + \frac{\sin^2(\beta_i - \alpha)}{k_{\min}} \quad (2.36)$$

Make the double-logarithmic curve chart of each observation well's pressure and the pressure derivative, find out the values at the points of intersection of the pressure and pressure derivative curve, and calculate the value k_{ni} of the directional permeability of each well. For a given well group, β_i can be known from Fig. 2.14. Then, for each observation well, substitute k_{ni} and β_i values into Eq. (2.36):

$$\begin{cases} \frac{1}{k_{r1}} = \frac{\cos^2(\beta_1 - \alpha)}{k_{\max}} + \frac{\sin^2(\beta_1 - \alpha)}{k_{\min}} \\ \frac{1}{k_{r2}} = \frac{\cos^2(\beta_2 - \alpha)}{k_{\max}} + \frac{\sin^2(\beta_2 - \alpha)}{k_{\min}} \\ \frac{1}{k_{r3}} = \frac{\cos^2(\beta_3 - \alpha)}{k_{\max}} + \frac{\sin^2(\beta_3 - \alpha)}{k_{\min}} \end{cases} \quad (2.37)$$

The value α , $k_{\max}$, and $k_{\min}$ can be obtained by calculating the Eq. (2.37), on the basis of which the anisotropy degree A and the average plane permeability $\bar{K}$ of the reservoir can be calculated:

$$A = \frac{k_{\max}}{k_{\min}}, \quad \bar{k} = \sqrt{k_{\max}k_{\min}} \quad (2.38)$$

2.3.4 Method for Identifying the Main Permeability of the Fractured Reservoir and the Main Fracture Direction

The fractured reservoir is composed of numerous fractures and numerous double-porosity media which are divided by fractures and are made up of general porous media structures. Cracks are the main passage of fluid in the formation, and bedrock is the main reservoir space for fluid accumulation in the formation. Cracks usually have a main direction, in which the permeability is the maximum, and the direction of the vertical permeability is the minimum. In 1995, Q. Ma and D. Tiab proposed a method for determining the fracture direction with three observation wells. They assume that the matrix is isotropic, and the anisotropy of the formation is generated by cracks. For anisotropic reservoirs, permeability can be regarded as a tensor. Using the observation wells in three different directions, the main direction of the cracks can be determined. In 1997, NIE Lixin et al. proposed the method to determine the fracture orientation of anisotropic naturally fractured reservoirs.

Based on the dual-porosity physical model, the mathematical model for interference well testing in the fractured reservoir is established. Laplace transform method is used to find the solution of the model in Laplace space. The approximate solution of the pressure distribution in the reservoir is obtained through numerical reversion with Stehfest method. According to the genetic algorithm's characteristics of self-adaption to global optimization probability search, the main permeability and the main crack direction of the fractured reservoir are identified by using automatic matching technique.

Take the perturbed well as the origin and the maximum permeability direction as x -axis, mark permeability as k_x , assume that y -axis is vertical to the x -axis, and mark its permeability as k_y , then

$$\sqrt{\frac{k_x}{k_y}} \frac{\partial^2 p_D}{\partial x_D^2} + \sqrt{\frac{k_y}{k_x}} \frac{\partial^2 p_D}{\partial y_D^2} = \omega \frac{\partial p_D}{\partial t_D} + (1 - \omega) \frac{\partial p_{mD}}{\partial t_D} \quad (2.39)$$

$$p_D = \frac{172.8\pi K h p}{q \mu B}, \quad t_D = \frac{3.6\eta}{r_w^2}, \quad x_D = \frac{x}{r_w}, \quad y_D = \frac{y}{r_w}, \quad \eta = \frac{K}{\mu(\phi C_t)_{f+m}} \quad (2.40)$$

$$K = \sqrt{k_x k_y}, \quad \omega = \frac{(V\phi C_t)_f}{(V\phi C_t)_{f+m}}, \quad \lambda = \alpha r_w^2 \frac{k_m}{k} \quad (2.41)$$

In the equation,

B	is the volume factor, m^3/m^3
C	is wellbore storage factor, m^3/MPa
Φ	is the porosity
V	is the pore volume
M	is the fluid viscosity, mPa s
C_t	is the composite compressibility, MPa^{-1}
K	is the average reservoir permeability, μm^2
k_m	is the bedrock system permeability, μm^2
h	is the reservoir thickness, m
D, W, f and m	are, respectively, expressed as dimensionless quantities, active well, fracture system, and bedrock system.

By using Laplace transform to obtain the solution to the model in Laplace space and using Stehfest method for numerical reversion, the pressure distribution in the reservoir can be found out as:

$$p = a_1 c_1 \sum_{i=1}^n u_i Q \left[a_1 c_2 \frac{i}{t}, a_2, a_3, a_4, a_5, a_6, a_7 \right] \quad (2.42)$$

where

$$\begin{aligned} c_1 &= \frac{qB\mu}{172.8\pi h}, \quad c_2 = 0.19\phi\mu c_t r_w^2 \\ a_1 &= \frac{1}{K}, \quad a_2 = \omega, \quad a_3 = \lambda, \\ a_4 &= C_D, \quad a_5 = S, \quad a_6 = r_{D1}, \quad a_7 = r_{D2} \end{aligned} \quad (2.43)$$

In the equation,

r_{D1} is the dimensionless distance between observation well 1 and the perturbed well;

r_{D2} is the dimensionless distance between observation well 2 and the perturbed well.

Take the perturbed well as the origin and the right-direction angle obtained by rotating clockwise from the north as the direction angle. Mark the direction angles of the observation wells 1, 2 and the main crack direction as θ_1 , θ_2 and θ , and we write

$$c = \sqrt{\frac{k_x}{k_y}}, \quad d_i = \left[\frac{r_{Di} r_w}{r_i} \right]^2, \quad i = 1, 2 \quad (2.44)$$

then,

$$\begin{cases} \frac{1}{c} \cos^2(\theta - \theta_1) + c \sin^2(\theta - \theta_1) = d_1 \\ \frac{1}{c} \cos^2(\theta - \theta_2) + c \sin^2(\theta - \theta_2) = d_2 \end{cases} \quad (2.45)$$

Remove c and we can get

$$\begin{aligned} & [d_1 \sin^2(\theta - \theta_2) - d_2 \sin^2(\theta - \theta_1)] \times [d_2 \cos^2(\theta - \theta_1) - d_1 \cos^2(\theta - \theta_2)] \\ &= [\cos^2(\theta - \theta_1) - \cos^2(\theta - \theta_2)]^2 \end{aligned} \quad (2.46)$$

The direction angle of the main crack direction θ can be obtained from the above equation. After θ_1 is found out, the main permeability of the reservoir k_n can be obtained from the equation:

$$\bar{k} = \sqrt{k_x k_y} = \frac{1}{a_1} \quad \text{and} \quad c = \sqrt{\frac{k_x}{k_y}}$$

2.4 Influence of Permeability Direction on Development Efficiency

Due to the control of geological factors such as deposition, the values of reservoir permeability often show the characteristics of anisotropy. Permeability anisotropy is the basic property of the reservoir, especially the fluvial reservoir, which has a negative effect on the effective exploitation of the reservoir.

2.4.1 Influence of Vertical Heterogeneity of Permeability on Water Flooding Recovery

Many factors influence the recovery of water flooding in oil reservoirs. They can be divided into two categories: geological factors and development factors. Of the geological factors, the vertical heterogeneity of reservoir permeability is an important factor that influences the water flooding recovery. Heterogeneity is mainly characterized by the non-uniform use of the oil layer. Especially in the condition of multilayer commingled production, some reservoirs are not used or poorly used. This leads to a great impact on the oil recovery of the entire field, with a decline from 5 to 10 % generally. In the water injection well of multilayer commingled production with the same water injection pressure, the water absorption capacity per unit thickness varies greatly in different layers. The actuating

differential pressures in different reservoir water injection wells are different, and oil productions and pressures of the oil layers in the oil production wells are quite different. Due to the difference between layers in the same well, good layers absorb more water and produce more oil with the waterline advancing rapidly; poor layers absorb less water and produce less oil with the waterline advancing slowly. Therefore, vertical heterogeneity results in monolayer breakthrough phenomenon in the process of water flooding development, making the water displacement volume sweep coefficient very low.

The vertical heterogeneity distribution of reservoir permeability is an important factor that influences the recovery of water flooding. The vertical heterogeneity distribution of reservoir permeability can be described by the following six factors: micro-cyclicity, distribution type, variation coefficient (V_k), average permeability, ratio of vertical permeability to horizontal permeability (K_v/K_h), and the specific arrangement of permeability. In order to further improve the research of the effect of vertically heterogeneous distribution of reservoir permeability on reservoir water flooding recovery, numerical simulation method is adopted. Under the condition that the factors such as wettability, capillary force, and gravity are equal, nearly 200 trial plans of water flooding recovery are made based on the calculations with the following factors taken into account: micro-cyclicity, distribution type, coefficient of variation, K_v/K_h value, the position of maximum permeability layer ($K_{\max}$ layer), and so on. This helps study the change law of water flooding recovery in reservoirs with different distributions of permeability heterogeneity.

- a. The water flooding recovery of the cyclic type reservoir decreases with the increase of the coefficient of variation. The greater the K_v/K_h value, the greater the effect of variation coefficient on water flooding recovery in the normal cycle reservoir and the less the effect of variation coefficient on water flooding recovery in the reverse cycle reservoir.
- b. In the normal cycle reservoir, when the variation coefficient is less than 0.5, the recovery increases with the increase of the K_v/K_h value; when the variation coefficient is less than 0.5, recovery decreases with the increase of the K_v/K_h value. In the reverse cycle reservoir, recovery increases with the increase of the K_v/K_h value, no matter how big it is. And the greater the variation coefficient, the greater the effect of K_v/K_h on the recovery of the reservoir.
- c. When variation coefficients and K_v/K_h values are different, the normal cycle reservoir and reverse cycle reservoir have different water drive recovery rates, and they increase with the increase of the variation coefficient and the K_v/K_h value.
- d. As the $K_{\max}$ layer moves from the bottom to the top of the reservoir, the water flooding recovery in the normal cycle reservoir stays the same in the beginning and then gradually decreases to the minimum and finally rises rapidly. The greater the variation coefficient and K_v/K_h value, the greater the influence of the $K_{\max}$ layer position on the water drive recovery of reservoirs.
- e. For the reservoirs of lognormal distribution, $\Gamma(x)$ distribution, and $\Gamma(x^2)$ distribution, the change law of water flooding recovery is the same as the change of

the variation coefficient, the K_v/K_h value, and the $K_{\max}$ layer position. When the other conditions are identical, the efficiency order (from large to small) of the reservoirs of the three types of distribution in terms of water flooding recovery is lognormal distribution, $\Gamma(x)$ distribution, and $\Gamma(x^2)$ distribution reservoir.

2.4.2 Influence of Lateral Heterogeneity of Permeability on Water Flooding Recovery

The reservoir with severe lateral heterogeneity can obtain good recovery if water is injected into high-permeability zones and oil is produced in the low-permeability zones. The equivalent permeability of the entire reservoir is obviously influenced by the relative distance between the lateral heterogeneity reservoir and the water injection well, because the oil displacement efficiency of the core is related to the value of the equivalent permeability. Therefore, in the case of lateral heterogeneity, the equivalent permeability is definitely low if the mode of water injection in the low-permeability zone and oil producing in the high-permeability zone is adopted. The lower the core permeability variation coefficient is, the more homogeneous the throats are, which means the water breakthrough is relatively weak and the water-free oil recovery is relatively high. Weak water breakthrough phenomenon is bound to make the most of the throats flooded and the oil displacement efficiency of core improved.

The effect of lateral heterogeneity of permeability on gas reservoir development: The macroscopic heterogeneity of reservoirs includes two aspects: quantity and morphology, that is, heterogeneity degree and heterogeneity distribution characteristics, the latter of which can be divided into the form of the plane and vertical (in layer and interlayer) heterogeneity distribution. The influences of intrastratal heterogeneity, including that of thick oil/gas layers of different rhythms and that of thin interbeddings with great variations, on gas reservoir exploitation are different in every way. Similarly, the influences of the degree and the distribution characteristics of areal heterogeneity on oil-and-gas reservoir development index are different. Especially for single layer development, multiple layer series (subsection) development, moving-upward-segment-by-segment development, the effect of areal heterogeneity on development efficiency is more prominent than that of vertical heterogeneity.

- a. Areal heterogeneity exerts an important influence on edge water–gas reservoir production performance. Permeability variation coefficient (V_k) is well related to gas recovery rate and cumulative water–gas ratio (N_w/N_g).
- b. The distribution of areal heterogeneity also has a great influence on the exploitation of edge water–gas reservoir. In the case of the same heterogeneity, when the high-permeability zone is parallel to the producing well array or distributed along the long axis of the gas reservoir, the gas recovery rate is

- minimum; when the high-permeability zone is perpendicular to the long axis of the reservoir, the natural gas recovery rate is high; the natural gas recovery of the high-permeability zone of dispersive distribution is between the two above.
- c. The higher the heavy constituents of the gas reservoir, the smaller the effect of heterogeneity.
 - d. When non-hydrocarbons are contained in gas components, the natural gas volume and the phase state of condensate system may be more accurately calculated with the PR state equation.

2.4.3 Influence of Permeability Anisotropy on Well Pattern Arrangement

The anisotropic reservoir has the effect of disruption and reorganization on the development well pattern, which makes it difficult to control the production effect of the well pattern and seriously affects the production and recovery of crude oil. The effect of disruption and reorganization of the anisotropic reservoir in the water injection development well pattern are illustrated by a square five-spot well system. Set up a coordinate system, whose principal directions of anisotropic permeability are, respectively, x - and y -axes. The anisotropic permeability in X -direction and Y -direction are, respectively, k_x and k_y . The angle between the direction of the water injection (oil production) well pattern and the main direction k_x is α . The well pattern is deployed as in Fig. 2.15.

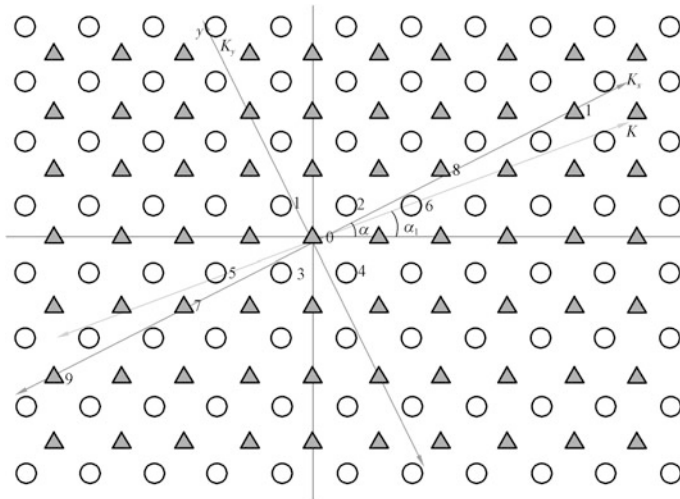


Fig. 2.15 Square five-spot well system of an anisotropic reservoir

In order to analyze the development effect of the well pattern, the anisotropic reservoir is converted into an equivalent isotropic reservoir, for which a coordinate transformation is used:

$$\begin{cases} x' = x\sqrt{K/K_x} \\ y' = y\sqrt{K/K_y} \\ K = \sqrt{K_x K_y} \end{cases} \quad (2.47)$$

The essence of the coordinate transformation is to extend the original flow space $\sqrt{K/K_x}$ and $\sqrt{K/K_y}$ times in x - and y -directions, respectively. Through the coordinate transformation, the original anisotropic reservoir with main permeability K_x and K_y is transformed into an equivalent isotropic reservoir with permeability value K . The well pattern (Fig. 2.15) in the original anisotropic reservoir will become an equivalent isotropic reservoir. The following is the change of the well pattern.

Suppose $k_x > k_y$, then $\sqrt{K/K_x} < 1$ and $\sqrt{K/K_y} > 1$. The above coordinate transformation is equivalent to the fact that the anisotropic reservoir space is compressed by $(K_x/K_y)^{1/4}$ times in x -direction, while in y -direction it extends $(K_x/K_y)^{1/4}$ times, and the well pattern changes with it. If any one of the included angles is marked as α and the main direction K_x is supposed to be parallel to the connecting line between 9, 7, 0, 8, and 10 wells, then the deformed well pattern of the equivalent isotropic reservoir transformed from the square five-spot well pattern in Fig. 2.15 is shown in Fig. 2.16a. The arrangement of 0, 1, 2, 3, and 4 wells which belong to the same injection-production unit is scattered, especially 0, 1, and 4 wells being three well arrays apart from each other; 0, 7, and 8 wells which used to be disconnected become adjacent wells in the same well array. All the other injection-production units are also disrupted and reorganized. The development effect of the row well pattern in Fig. 2.16a is absolutely different from that of the square five-spot well pattern in the general (isotropic) reservoir, but its development

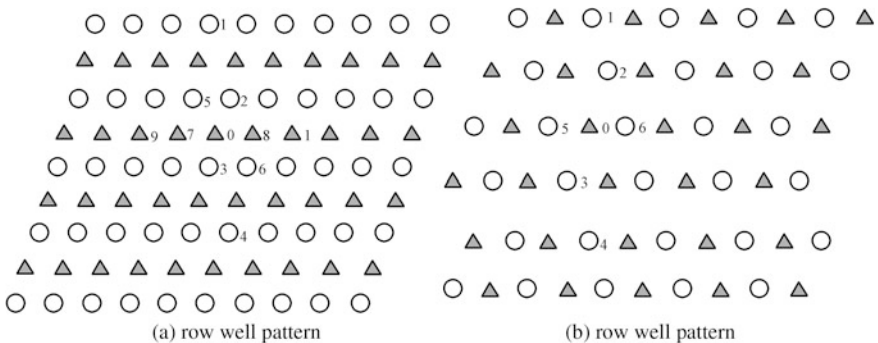


Fig. 2.16 Deformed well pattern with different angle equivalents

effect is equivalent to the square five-spot well pattern in Fig. 2.15. In Fig. 2.15, the production well No. 1 and No. 4 and the injection well No. 0 are arranged in the same injection-production unit, but it is difficult for the production wells to increase energy by the injection well No. 0. It is the same case in the other injection-production units. In Fig. 2.16a, the distance between the injection well row and production well row is so great that the energy in the area of water injection wells is difficult to spread to the production well regions, which leads to the high pressure near the water injection well and the failure of water injection. On the other hand, the low pressure near the production well leads to the failure of the liquid production and insufficient production capacity. This phenomenon often occurs in the development of an actual fracture reservoir.

If the angle α between the direction of the maximum principal permeability and the direction of the well array is changed and suppose the angle between the main direction K_x and the direction of the well array α (the main direction k_x) is parallel to the connecting line between No. 5, 0, and 6 wells (Fig. 2.15), then we have the transformation of the equivalent isotropic reservoir and its deformed well pattern, as shown in Fig. 2.16b, that is, the square five-spot well pattern in Fig. 2.15 is transformed into the mixed row well pattern, in which the production well and the water injection well are closely linked to each other. Number 0, 1 and 4 wells are two well arrays apart from each other, and No. 0, 5, and 6 wells become adjacent wells in the same well array. Obviously, any water injection in this well pattern will make the production well soon flooded. However, the flooded wells and the water injection wells are not in the same injection-production unit and relationship of injection and production in the well pattern is in disorder, so water cut rises fast, and oil production and recovery are very low. This phenomenon often occurs in an actual oilfield development in practice.

For the arbitrary angle α , the well pattern in Fig. 2.15 is related to an equivalent deformed well pattern. In theory, if $(K_x/K_y)^{1/4}$ value is big enough, the original well pattern will become the well pattern shown in Fig. 2.16a when the main direction K_x is parallel to the connecting line of any two wells; when the main direction K_x is parallel to the connecting line between any water injection well and production well, the original well pattern will become the well pattern similar to that in Fig. 2.16b. When $(K_x/K_y)^{1/4}$ is not big enough, or the main direction K_x is not parallel to the connecting line between any two wells, the original well pattern will become an irregular form between the two kinds of well pattern above.

All the geometric parameters of the deformed well pattern, such as well spacing, well array spacing, and inclination, are determined by K_x , K_y , and α , but the well pattern becomes very complex with the changes of K_x , K_y , and α . The bigger the $(K_x/K_y)^{1/4}$ value is, the more sensitive the change of the well pattern is to α . A very small change of α will lead to a completely different form of the well pattern. For example, when α_1 in Fig. 2.15 changes continuously until it comes to α , the isotropic reservoir well pattern obtained will change for numerous times between Fig. 2.16a, b in theory, because the line on which K_x is located will sweep over infinite water injection wells and production wells. The lines linked No. 0 well, and these wells are infinite, which means that the direction of major permeability will

become parallel to the connecting line between the oil wells and that between the oil well and water injection well for infinite times alternately. Further studies reveal that the above changes reach the maximum when sensitivity is at 22.50° . Of course, due to the actual area, the limited number of wells, and limited $(K_x/K_y)^{1/4}$ values obtained, the change frequency of the well pattern is limited as well. But the change law of the well pattern is consistent with the result of theoretical analyses.

Obviously, the change mechanism above works in any form of well patterns of the anisotropic reservoir. The anisotropy of reservoir permeability is a process of disruption and reorganization of the general development well pattern.

2.4.4 Influence of Water Flooding Direction on Development Efficiency

Because of the differences in reservoir sedimentary environments, sedimentary conditions, sedimentary styles, and sedimentary periods, the physical properties of reservoirs can be very different, which are characterized by different sedimentary micro-facies, thus the heterogeneity of reservoirs. Because of the provenance direction and the directivity of permeability caused by the trend of the river, the well patterns should be arranged according to the areas of different sedimentary micro-facies. Figure 2.17 is about two kinds of typical different sedimentary models of the braided river and meandering river. Obviously, the physical properties of reservoirs are different in the regions of different micro-facies. For a straight well, the water injection well arrays should be vertical to the direction of main permeability, because the water flooding effect can be better. For horizontal wells and complicated wells, water flooding direction should be parallel to the direction of

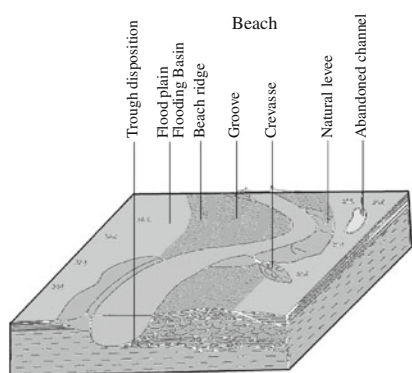
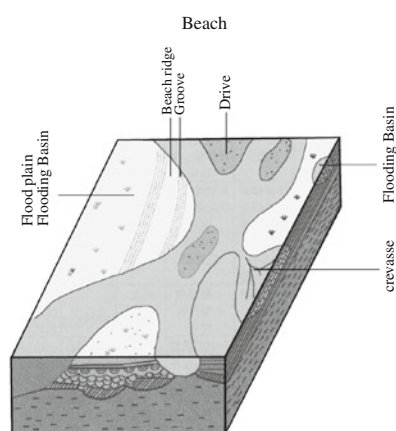


Fig2-8 The guan 3-4 three-dimensional pattern of meandering river of zhongyi zone in gudao oil field

(a) model of three-dimensional facies of a meandering river



(b) model of three-dimensional facies of a braided river

Fig. 2.17 Two typical models of fluvial deposition

main permeability and horizontal well section should be perpendicular to the direction of main permeability so as to obtain a greater drainage area.

Yan Baozhen et al. have studied the effect of water flooding when the water drive direction and main permeability direction from different intersection angles in the injection-production system of five-spot well pattern and the nine-spot well pattern. The streamline and the leading curve when the angles between water injection well arrays and the maximum principal permeability direction are 0° , 22.5° , and 45° , respectively, are shown in Figs. 2.18, 2.19, 2.20 and 2.21. According to the flow line analysis and calculation results, it is found that if the water flooding direction is consistent with the direction of the maximum principal permeability in the five-spot pattern, the sweep efficiency is high and the fluid injection occurs late. For the nine-spot well pattern system, if the well pattern is arranged with an angle of 45° between the line connecting the water injection well and the edge well, and the maximum principal permeability direction in nine-spot well pattern, the sweep efficiency is high and the agent injection occurs late.

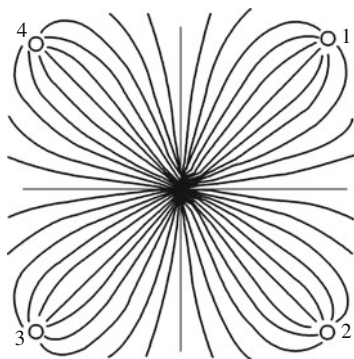


Fig. 2.18 Streamlines and front curves of five-point system in homogeneous reservoir. 1, 2, 3, 4 is production well

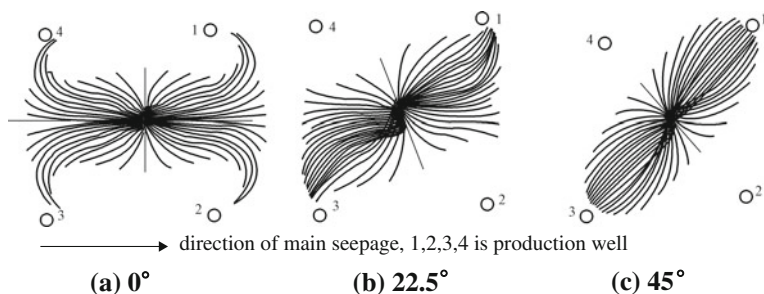


Fig. 2.19 Streamlines and front curves when the angles between the injection well array in five-spot system and the maximum principal permeability are different

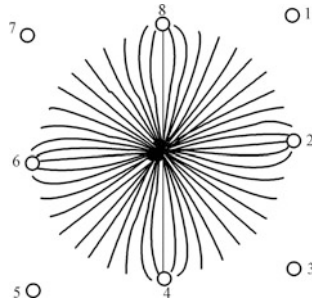


Fig. 2.20 Streamlines and front curves of nine-point spot system in a homogeneous reservoir. 1, 2, 3, 4, 5, 6, 7, 8 is production well

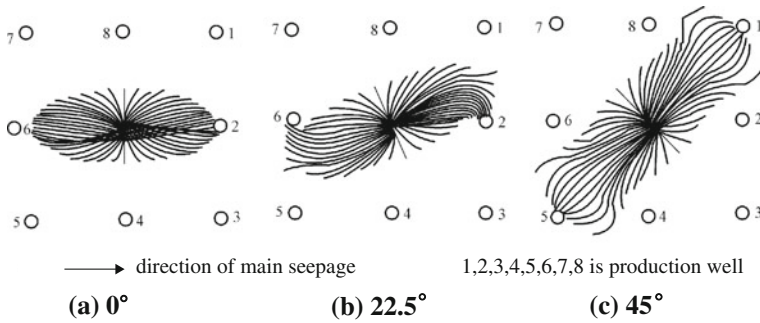


Fig. 2.21 Streamlines and front curves when the angles between the injection well in nine-spot system and the maximum principal permeability are different

2.4.5 Influence of Fracture Orientation on Water Drive Efficiency

The recovery of water drive reservoirs is controlled by two main factors, that is, macro-sweep efficiency and micro-sweep efficiency. And the sweep efficiency of injection fluid in the formation is directly influenced by the orientation and length of fractures, especially for low-permeability reservoirs.

In this study, a water displacing oil experiment is made, taking the reservoir core with natural fractures in Wen 13 North Block Es3 as the study object, more specifically four rock samples: those with fractures whose azimuths are 0° , 45° , and 90° , respectively, and those without cracks. The experimental temperature of water flooding is 30°C , the oil/water property is consistent with the phase permeability determination, and the driving speed is $30\text{ cm}^3/\text{h}$. The experimental results are shown in Table 2.4.

Table 2.4 Effect of crack orientation on water flooding recovery

Core number	Length of the core (cm)	Core diameter (cm)	Air permeability ($10^{-3} \mu\text{m}^2$)	Driving speed (cm^3/h)	Irreducible water saturation (%)	Fracture azimuth ($^\circ$)	Water displacing oil efficiency
Wen 13-45-4-2	6.87	2.51	9.54	30	0.306	90	0.6432
Wen 244-3-3	6.11	2.51	10.12	30	0.327	45	0.5716
Wen 244-1-1	5.76	2.51	13.66	30	0.342	0	0.425
Wen 13-28-1-2	6.32	2.51	11.12	30	0.329	No fracture	0.5872

From the experimental data in Table 2.4, it is found that the highest water flooding recovery rate of the rock with fractures vertical to the flow direction is 64.32 %, which is 5.6 % higher than that of the rock without fractures and 21.82 % higher than that of the rock with fractures parallel to the flow direction. Therefore, the injection-production well pattern should be adjusted before the water injection to improve the sweep coefficient in accordance with the crack orientation. In view of the characteristics of the cracks in Wen 13 North Block Es3 reservoir, the well pattern should be adjusted properly on the basis of a careful study of the fractures in order to achieve a higher sweep coefficient.

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