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Preface

The research of reasonable well patterns in the oil and gas field development has received significant attention in recent history. In the 1940s, M. Muskat made studies on the flow of homogeneous fluids through porous media. Several authors in literature advanced theories about the relationship between reservoir sweep efficiency and injection models, i.e., well patterns, when the reservoir is homogeneous and the mobility ratio is 1. Subsequently, in the 1950s, researches clarified the changes of reservoir sweep efficiency after water-breakthrough in the water-flooding process under the condition of random mobility ratios. However, in the late 1950s, the method of oil production with sparse well pattern and great differential pressure was proposed by some other researchers and widely applied, but their application failed in practice. In the late 1960s, V.N. Shelkachev in former Soviet Union developed an empirical formula for the determination of final oil recovery and well spacing density. Similarly, some scholars of Daqing Oilfield suggested that the well pattern deployment should be based on the size of reservoir sand and that the relationship of water drive control and well pattern is determined by the oil sand map. In the early 1980s, Tong Xianzhang proposed a method to optimize the well pattern leading to the realization of maximum production. In the early 1990s, Qi Yufeng presented the well pattern system theory. Moreover, Lang Zhaoxin and others initiated the research on the production of horizontal well patterns. In 2003, Liu Dehua proposed the concept of the vector well pattern and corresponding well spacing methodologies and has ever since been working on them. In 2005, Liu Yuetian from China University of Petroleum studied the water injection methods and well arrangement theories of anisotropic reservoir.

With the continuous development of well pattern research, understanding of the well patterns has also been in progress. Since the well pattern is very important in the production of oil and gas fields, the production scale, the life of production, and the economic benefits of oil and gas fields are determined by the selection, deployment, and adjustment of well patterns to a large extent. Moreover, the onshore oil and gas fields in China are mostly heterogeneous reservoirs. The optimization of well patterns is particularly important. Therefore, the establishment of well pattern optimal control theory plays an important guiding role in improving the oilfield development.

With the development of oil and gas fields and constant change of drive modes, the development system becomes increasingly complex. This creates much demand for further and detailed research on the well pattern or well pattern efficiency. From the perspective of system, the well pattern system which consists of individual wells is a subsystem of oil and gas field development system. Consequently, in order to better handle the challenge of well patterns, it is ideal to optimize the well pattern holistically through the combined optimization of individual wells. This involves the combined evaluation of all the major inputs such as drainage radius of single wells, multi-well interference and injection-production balance, and the position and function of well patterns in the system of oil and gas field development, taking the problem as a socially complex giant system. For the optimization of well patterns, the approach should involve the principle of a minimum number of wells, the largest controlled drainage area, a higher hydrocarbon recovery rate, a satisfactory or an acceptable oil and gas production rate, the flexibility of the well pattern, the lowest managerial cost of ground facilities and so forth.

The author has been engaged in the research on oilfield development theory and application, especially in the systematic research on the well pattern. Combined with the oilfield development practice, he has made a number of significant proposals toward the well pattern optimal control theory.

This book introduced in detail the geological foundation of well pattern optimal control, reservoir direction characteristics and their evaluation methods, the concept of the vector well pattern and corresponding well pattern deployment methods, well pattern control principles and the determination methods of well spacing density in different development phases, the optimization of horizontal wells and the design principles and requirements of mixed well pattern of the horizontal and vector wells, etc. This research finding laid the theoretical foundation for the effective development and secondary development of heterogeneous sandstone reservoirs and proposed a number of effective methods and measures to significantly improve the water-flooding effect.

The book derives its usefulness from the author's various research findings. As the first edition, it is likely for readers to come across a few mistakes. Therefore, the author is open to and welcomes all corrections and constructive suggestions.

Wuhan, China
June 2016

Dehua Liu
Jing Sun

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Contents

Chapter 1
Geological Foundation of Well Pattern Optimization

The whole oilfield development process, including program design, development strategies, exploitation measures, enhanced oil recovery application, development adjustment, and comprehensive treatment, cannot go without understanding of and research on the law of reservoir geology. From development to the end, reservoir description runs through the whole process. Reservoir engineers are constantly understanding and studying reservoirs, including reservoir geology, oilfield development dynamics and so on. Modern fine description of reservoir is the geological foundation of well pattern optimization and control in the process of oilfield development. Without accurate knowledge of reservoir distribution law and characteristics, the arrangement of well pattern would lose the foundation, let alone optimize the well pattern. This chapter mainly discusses the basic method and process of the fine description of heterogeneous sandstone reservoirs, and the main problems, especially the description methods of heterogeneous reservoirs, and then finds out the geological features of reservoirs related to well pattern optimization and control.

The concept and method of reservoir description were first proposed by Schlumberger Ltd. in the 1970s and their essence is multi-well evaluation, which combines well logging and geology. In the 1980s, with the mushroom growth of seismic process and interpretation technology, reservoir description with the seismic method was suggested as the main content. Then, reservoir description developed from macro to micro and from qualitative description to quantitative forecasting until the 1990s, when the modern reservoir description technology involving multi-discipline cooperative research came into being.

Since the 1980s, when this technology was introduced into China, every oilfield, with improving the ultimate recovery rate of high-water cut oilfields as the primary purpose, has carried out the technical research of fine reservoir description with a great breakthrough, which is promoted and applied in large areas with a complete set of technology and remarkable achievements.

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1.1 Overview of Fine Reservoir Description

The concept of reservoir description is that when an oilfield is discovered, engineers use all possible data and means to make a comprehensive description of its geological features of reservoirs. It has gone through the process from qualitative to quantitative description and if the data of an oilfield are abundant and the reservoir parameters and remaining oil forecast are accurate, then it is called reservoir characterization. In the 1980s, relative concepts and methods were introduced into China, where reservoir description research began to be carried out. Through about 30 years' efforts, Chinese geologists, according to the data and for the purpose of description, have gradually built up the contents and methods of the exploration-phase description, initial stage of development description, and middle-and-late stage of development description, and achieved important effects in oilfields all over the country, finally forming the necessary reservoir geological research methods to calculate the reserves and formulate development or adjustment programs.

1.1.1 Stages of Reservoir Description

From the discovery of an oilfield to its abandonment, exploration and development have to go through many repetitions: from recognition and practice to rerecognition and repractice. Various kinds of means and data are needed at every step to have a deep understanding of the reservoir so that further adjustment measures can be made to achieve practical benefits of crude oil production. According to ecological data at different stages of exploration and development, and ecological tasks that need to be fulfilled, the contents and methods of reservoir description vary greatly and the required goals are different. Therefore, a brief introduction is first made to reservoir description at different stages of exploration and development.

There is not much difference between the way of dividing stages of oil/gas exploration and development in China and that in other countries. Generally speaking, it can be divided into four stages: the exploration appraisal stage, early development stage (program design and pilot production, with water cut less than 20 %), the middle development stage (program implementation, monitoring, and adjustment, with water cut from 20 to 60 %), and the high-water cut stage (tertiary oil recovery stage). And oilfield development stages accord with the development preparation stage, agent development stage, and deep development stage (Fig. 1.1).

Tasks of geology and reservoir engineering at every stage are all making good use of the acquired reservoir information and data at this stage to understand and evaluate the geological features of reservoirs at this stage in order to supply a geological basis for development measures at the later stage. Success or failure of reservoir description directly influences the development program implementation and crude oil production at the later stage. Of course, whether the development measures succeed or not depends not only on the accuracy of the geological features

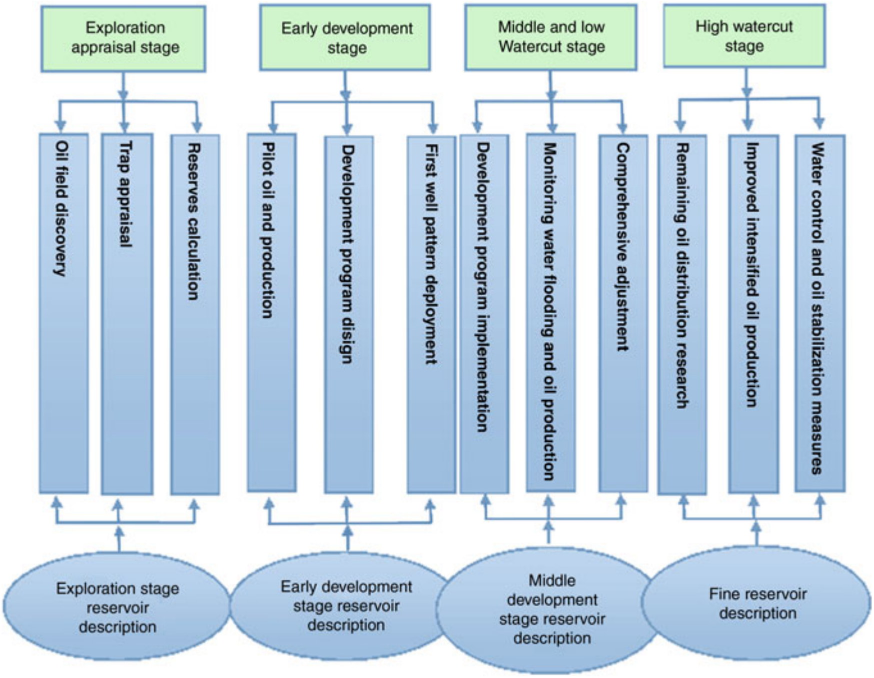


Fig. 1.1 Stage division and tasks of reservoir description

of reservoirs, but also on the restriction of engineering measures. The more accurately the key geological features of reservoirs are described and predicted, the higher the degree of coincidence at the later stage is and the higher the rate of success of reservoir description. New development stages and measures can achieve more abundant reservoir geological data and information and can also examine, modify, and improve the cognition of reservoirs. Therefore, reservoir description will continuously develop with the advance of development stages.

Reservoir descriptions at different stages have something in common, but there are great differences between each other. As the quality and quantity of the known basic data and control extent of oil and gas reservoirs are different, the development problems to be solved, and the key points and accuracy of reservoir description are also different. Therefore, based on the experience and lessons of reservoir description in China and other countries, and practical deeds of conducting oilfield reservoir description, the stages of reservoir description and exploration development are accordingly divided into the exploration stage, early development stage, middle-and-low-water cut stage, and high-water cut stage, or in other words, reservoir description of the exploration appraisal stage, early development stage, middle development stage, and enhanced oil recovery stage. The division of different stages is relative, because exploration is conducted progressively and so is reservoir description, which means it does not remain the same (Table 1.1).

Table 1.1 Main tasks, technology, and methods of reservoir description at different development stage

Stage	Tasks and contents of exploration and development	Tasks and contents of reservoir description	Technology and methods of reservoir description
Exploration appraisal stage	Ascertaining geological reserve and predicting the recoverable reserves; making feasibility evaluation on reservoir development technologically and financially; predicting possible production scale and putting forward planning development deployment; designing the outline of drilling, production and ground engineering	Trap parameters and form appraisal; division of macroscopic oil–gas–water system and analysis of its controlling condition; determining reservoir types; illuminating vertical reservoir macro properties and parameter properties; establishing the reservoir structural model	Determining reservoir structural skeleton based on regional geological and seismic data; predicting space distribution of sand bodies on the basis of reservoir sedimentology; combined research on geology and seismic data, such as reservoir horizontal forecast
Initial stage of development (program design stage)	By testing production, making decisions on development layer series, injection - production well patterns, oil production speed and stable production time; overall design of reservoirs, drilling, production and surface engineering; optimizing the best development program	Determining recoverable reserves; verifying the structure and oil–gas–water distribution; determining the sedimentary micro-facies type; predicting macroscopic distribution of layers, especially the major layers; establishing the reservoir geological conception model	Fine interpretation technology of seismotectonics; small layers division in contrast with all regions; reservoir sedimentary micro-facies description; logging wells reservoir appraisal; geological conception model establishment technology
Middle-and-low-water cut stage (program adjustment stage) high-water cut stage (EOR stage)	Determining the injection and production well, formulate the production and injection proration program. Timely adjusting the development	Logging wells reservoir appraisal; providing complete reservoir static parameters body; making oil–gas–water distribution graphs and structural graphs of all layers;	Fine logging wells reservoir appraisal technology; comprehensive reservoir prediction and oil–water distribution analysis; dynamic monitoring, reservoir numerical

(continued)

Table 1.1 (continued)

Stage	Tasks and contents of exploration and development	Tasks and contents of reservoir description	Technology and methods of reservoir description
	program; monitoring and analyzing development dynamic, adjusting the injection and production relationship, and implementing measures of increasing production and injection; analyzing the current situation and potential of reserve utilization, energy maintenance and utilization; drawing up comprehensive adjustment programs about layer series and well patterns, and putting them into effect	small layers in contrast with the whole field; sedimentary micro-facies research; establishing the reservoir database; fine research on pore structures and clay minerals; synthesizing static and dynamic data, perfecting reservoir static model and developing to the stage of predicting model	simulation and comprehensive interpretation; reservoir static model establishment technology
High-water cut stage (EOR stage)	Research on remaining oil distribution and control factors; Conducting all types of experiments to improve water driving oil, and putting forward water control and oil stabilization measures; making experiments in tertiary oil recovery and pilot test, and popularizing the experiment result; making the tertiary oil recovery program	Small layers microstructure and micro-facies research; flowing units' division and contrast; research on the dynamic variation of reservoir physical properties in the process of water injection; remaining oil saturability, and distribution research; and establishing the reservoir dynamic model at the high-water cut stage	Small layers microstructure research technology; flowing units research technology; water flooded layers logging interpretation technology; research on the dynamic variation of reservoir physical properties; reservoir 3D geological model establishment technology; integration technology of geology, reservoir, and numerical simulation

1. Reservoir description at the exploration stage

Not many data are available at the exploration stage, with two-dimensional seismic data as the main part. The density of the measuring line is 2 km × 2 km or 1 km × 1 km. As for well drilling, the data are only about one or more exploratory wells or evaluation wells, with well spacing more than a certain number of kilometers. On the basis of comprehensive drilling, well logging, and seismic data, a comprehensive research on and evaluation of reservoirs can be carried out, which can directly supply a reliable geological basis for development feasibility research and development program design so as to successfully build the geological conceptual model.

The main tasks of reservoir description are as follows, using drilling data of a few exploratory wells or evaluation wells and seismic information data with theoretical guidance of oil geology, to conduct reservoir appraisal and to calculate the proven geological reserves and forecast the recoverable reserves; discussing deployment of evaluation wells and getting kinds of development design parameters to expand exploration results; and if the evaluation zone is small, then deploying development ways and well patterns and giving suggestions on production engineering facilities and estimating the production scale that may be reached, making economical evaluation for the designed program and analyzing feasibility of development program.

Due to the particularity of the reservoir exploration stage, the research tasks and contents should focus on the following eight aspects:

a. Structural shape, faults, fracture distribution, and development extent;
b. Preliminary division and contrast of reservoir, and the prediction of the lithology, geometrical morphology, and lateral continuity of reservoir and heterogeneity features;
c. Analyses of and researches on reservoir sedimentary facies and diagenetic history;
d. Lithology and physical property standards for interlayers, and confirming interlayers' thickness and spacious distribution condition;
e. The properties of oil, gas, and water in the reservoir and the law of spacious distribution;
f. The changes of the reservoir pressure field and temperature field;
g. Calculating the proven oil geological reserves;
h. Discussing other oilfield geological problems related to well drilling, oil production, storage, and transport process.

The above are the main factors of controlling and influencing the storage and flow of fluids in the reservoir, which influence the variations of geology properties of every reservoir in the development process. The core of reservoir development geological features is characterizing the reservoir heterogeneity, and it can be concluded into three main parts:

a. Reservoir structural features;
b. Reservoir architectural framework and spacious distribution of physical properties;
c. Fluid distribution and properties in the reservoir.

Reservoir description at this stage may supply the reservoir structural model. As far as reservoir and fluid geological models are concerned, only a framework can be put forward, which cannot meet the requirement of the conceptual model.

2. Reservoir description at the early development stage

When the first batch of production wells are put into production and the total water cut of an oilfield is below 20 %, reservoir description at the early development stage is conducted. Besides the fine description of comprehensive geological and seismic data, logging and multi-well reservoir appraisals are needed to supply a large number of reservoir appraisal parameters, conduct reservoir numerical simulation, and predict production capacities and economical benefits. The purpose of reservoir description at this moment is to build the reservoir geological conceptual model, to further implement the proven and recoverable reserves and to put forward a reasonable reservoir development program.

The reservoir geological models supplied at this stage mainly include the structure model, the reservoir geology (framework and sedimentary facies) model, and the fluid properties model. Of them, the reservoir geologic model is the core of the reservoir geology conceptual model. Comprehensive geological and logging appraisal of the systemic coring wells is needed. Other geological factors influencing the decision and measure of reservoir development need to be analyzed, e.g., whether the existing reservoirs tend to leak, flow by themselves, collapse, corrode, or expand, the distribution status of the pressure field, temperature field, and crustal stress field of reservoirs. All of the above belong to reservoir description as well.

3. Reservoir description at the middle-and-low-water cut stage

After water flooding, the total water cut ratio may rise up quickly (water cut ratio from 20 to 60 %), various adjustment measures are constantly taken, the second batch of production wells are already completed and well spacing shrinking makes most of the reservoirs controlled by wells. To effectively build the system of the injection-production well pattern, maintain optimal reservoir development status (e.g., to increase energy and reserves production rate) and obtain maximum crude oil production. To improve the ultimate recovery, reservoir description is still needed.

As far as reservoir description is concerned, logging multi-wells reservoir appraisal should be regarded as the main part at this stage, including supplying three-dimensional data of reservoir description, building the reservoir three-dimensional geologic model about reservoir geology framework from macro to micro, sand body connectivity, interlayers' distribution, pore structure, and reservoir sensibility, and also using reservoir numerical simulation technology to match dynamical production data to provide data of sweep efficiency about displacement of oil by water and remaining oil distribution, and put forward development program of vertical layer adjustment and horizontal injection-production well pattern adjustment. It is evident that reservoir description at this moment regards the fine reservoir (static) description as the major and dynamical description as the auxiliary, and the reservoir three-dimensional geological model that has been built has the function of dynamical forecasting.

4. Fine reservoir description on high-water cut stage

Fine reservoir description is different from the above, because it is conducted with the data of well logging and reservoir dynamic as the major sources after the development well pattern is completed and the oilfield is at high-water cut stage. The reservoir description of the high-water cut stage requires higher accuracy, which needs to not only build a complete three-dimensional reservoir geologic model, but also determine the space distribution of remaining oil and put forward specific measures of oil stabilization and water control, thus to achieve the goal of enhanced oil recovery. The detailed contents and methods are in the next section.

Main marks and accuracy requirement of reservoir description at different stages are shown in Table 1.2.

To sum up, reservoir descriptions at different exploration and development stages all refer to the reservoir geologic model, reservoir development program, and enhanced oil recovery. But totally, reservoir description at the exploration stage is to build the reservoir structure model and rough reservoir geologic concept model, that is to say, to typify, conceptualize, and abstract various geological features of reservoirs to represent the geologic model; reservoir description at the early development stage requires description of reservoir features and critical reservoir features to correspond to reality fundamentally and build the concept model of structure, framework, and fluid properties; the key point of reservoir description at the middle development stage is to conduct various detailed researches on static parameters of reservoirs, characterize the distribution law of reservoir heterogeneity features in three-dimensional space with as many data as possible, and build the reservoir three-dimensional geologic model. Therefore, at the high-water cut stage, fine reservoir description requires reservoir numerical simulation technology to dynamically forecast the distribution of the remaining oil, build the complete three-dimensional reservoir geologic model, and put forward feasible measures to improve oil recovery and supply a reliable geological basis for the control and adjustment of the well pattern.

Table 1.2 Main marks and precision requirement of reservoir description at different stages

Stage division	Research emphasis					Precision requirement		
	Major data	Series division	Sedimentary facies	Reservoir heterogeneity level	Water cut stages	Structure study precision	Geological model	Model grid precision
Exploration appraisal stage	Based on 2D earthquake, a few exploration wells and appraisal wells	Oil-bearing series, oil layer group	Sedimentary facies or subfacies	Reservoir scale (emphasis) series scale (plane, interlayer)	Anhydrous	Top surface or standard layer: 25000 structural graph describes faults above the third order	Structural geologic model	Determined by the number of seismic and drilling data
Initial stage of development	For the primary development well, there may be pilot test area or 3D earthquake data	Sand layer group, small layer	Sedimentary subfacies	Reservoir scale (plane, interlayer)	Water cut < 20 %	Top surface or standard layer: 10000 structural graph describes faults above the fourth order	Conceptual geologic model	
Medium-and-low-water cut period	Development well pattern forming, much logging data and secondary processing results, logging	Small layers	Micro-facies	Small layer scale, single-sand body scale	Medium-and-low-water cut 60–80 %	Oil layers 1:10000 structural graph, structural extent more than 10 m, area more than	Dynamic geologic model	3D grid 200 m × 200 m × 1.0 m

(continued)

Table 1.2 (continued)

Stage division	Research emphasis					Precision requirement		
	Major data	Series division	Sedimentary facies	Reservoir heterogeneity level	Water cut stages	Structure study precision	Geological model	Model grid precision
	layered test for dynamic data					0.3 km^2, fault distance more than 5 m, length more than 300 m		
High-water cut period fine reservoir description	Complete well pattern, rich dynamic data, infill well data, development earthquake data	Flowing units	Causing unit stone facies	Flowing units scale (emphasis), intralayer scale, pore scale	High-water cut > 80 %	Single top–bottom surface structural graph, structural area less than 0.1 km^2, block, fault: distance less than 5 m, length less than 100 m	3D prediction geologic model	3D grid 100 m × 100 m × 0.2 m

1.1.2 Purpose of Fine Reservoir Description

Many of China's old oilfields were discovered in the years of "joint-efforts battles," so the production capacity construction was carried out on a large-scale without reservoir description or fine reservoir geology research. As continental basin reservoirs have severe heterogeneity, after water flooding, the total water cut of these fields soon rose up to 80 %. At the moment, the basic problems, such as the reservoir geological model, were unclear, thus severely restricting the conduct of process measures, such as oil stabilization and water control. Therefore, fine reservoir description of oilfields in the high-water cut period can solve reservoir geological problems that have existed in the oilfields for many years, set up accurate reservoir geological models, figure out the distribution law of remaining oil, and then adopt effective engineering measures, thereby achieving the purpose of oil stabilization, water control, and enhancing oil recovery.

Modern oilfield development is marked by reservoir management, which means making good use of available human, technological, and financial resources, and gaining the maximum benefits from reservoir development with the minimum investment and operation cost through optimizing development methods. To realize this goal, engineers should correctly forecast the geological features of reservoirs and the production performance under different development conditions. The research contents include data collection, reservoir description, displacement mechanism, reservoir simulation, dynamic prediction, and development strategy.

Only by predicting geological features and laws of reservoirs correctly can specific development strategic decisions be made and the development method optimized. At present, it is generally believed that there are two technical supports in oilfield development, i.e., reservoir description and reservoir simulation, the mathematical theory, and computer technology of the latter basically settled. Although great progress has been made in reservoir description, much uncertainty still exists in reservoir geology, and it needs a pretty long-time effort to probe into some problems so as to reach satisfactory results. Practices have proved that the key point of success or failure of oilfield development is whether the cognition of reservoirs accords with the objective underground facts. Therefore, reservoir description is placed in a very important position in research in China and other countries. That is to say, making good reservoir description is necessary in reservoir management.

Geological features of reservoirs are complex and variable. Therefore, the purposes and tasks are different at different exploration and development stages, so the geological problems that need extra understanding are different. For instance, in the exploration period, the purpose is to discover the reservoir and the appraisal of trap conditions is more important than that of the reservoir's heterogeneity; it is just the opposite in oilfield development, for the purpose of geology research is to understand geological features of reservoirs. Geological features of reservoir development refer to what features the reservoir has to control and influence the oil and gas development process, and they also influence development measures. The core of reservoir geology research is reservoir heterogeneity characterization, and it can be concluded as the following three main parts:

a. Description of reservoir structure and architectural framework. Reservoir is constituted by one or more reservoir bodies and exists underground in certain structure forms. The structure phenomena about reservoir bodies, such as the geometrical morphology, scale, size, lateral connection and vertical stack, structure formation, fault, and fracture makeup one or more connected components where fluids like oil and gas can be stored and constantly flow. These connected components are separated from impervious rock layers and other obstructions. Delineating the outer edges of these connected components and describing their geometrical morphology and occurrence are equal to describing the reservoir architectural framework.
b. Description of space distribution of reservoir physical properties. Physical properties of reservoirs are marked by oil–gas property. The parameters of physical properties have different extent variations in space domain from macroscopic reservoir bodies to microscopic pore structures, and there exist variable discontinuous heat sources. These constitute the heterogeneity and anisotropism of reservoirs and have an influence on development effects to a large extent.
c. Fluid property and distribution in the reservoir. Only by containing a certain amount of hydrocarbons can reservoirs form oil and gas reservoirs. Or we can say that the three types of fluids, i.e., oil, gas, and water, exist in oil and gas reservoirs in certain phase states, occurrences, mutual contact relations, and reserves, whose analysis belongs to description of reservoir fluids. As generation, migration, storage, and buried conditions of oil and gas vary greatly, fluid properties and space distribution in different oil and gas reservoirs or just one reservoir vary greatly and also influence the process of oil–gas development.

Some properties of the strata coexisting with oil and gas reservoirs influence the development decisions and measures of the oilfield reservoir, such as the distribution of all regional pressure fields, temperature fields, and crustal stress fields, which belong to the accessory contents of reservoir description.

In conclusion, the main task of development geology is oil reservoir description, with formation description as the core, and the task of oil reservoir description is to reveal the development geology features of reservoirs. Reservoir development geology must be hierarchically described from the macro- to micro-level. Generally, with gradual depth into oilfield development, researches on geological features of reservoir development need to go deep hierarchically from macro- to micro-level as well.

Fine reservoir description generally refers to the research on the reservoir by comprehensive geology, physical geography, reservoir numerical simulation, and reservoir engineering after a period of water flooding to develop the oil reservoir, when the total water cut rises up to over 80 %. The research thus quantitatively depicts all kinds of parameters of reservoir sedimentology, structural geology, petrophysics, diagenesis, and reservoir engineering. By making up a reservoir geologic model reflecting reservoir properties and remaining oil distribution in the three-dimensional space, quantitative distribution data body of reservoir body and reservoir parameters in the three-dimensional space can be obtained, especially the quantitative variation law of permeability and remaining oil in field development units, which supply a detailed and quantitative geological basis for further intensified oil production or development program adjustment, thus reaching the goal of oil stabilization and water control.

1.2 Main Contents and Methods of Fine Reservoir Description

One of the important purposes of fine reservoir description is researching the distribution of remaining oil. After long-term water-flooding development in the fault-block reservoir, the remaining oil will disperse into unreachable places by the injected water, and the cleaning effect of injected water will lead to the change of reservoir pore structure. Therefore, to quantitatively understand the distribution states of remaining oil, fine reservoir description has to be conducted. As the complexity of reservoir geology exists, the contents and methods of fine reservoir description should include the following aspects: fine division and correlation of thin layers, analysis of microstructures, research on sedimentary micro-facies of thin layers, flow units, and technology of forecasting reservoir physical properties, three-dimensional geological model technology, and reservoir numerical simulation technology.

1.2.1 Fine Division and Contrast of Reservoirs

Fine division and contrast of reservoirs, and building the reasonable stratum structure model (sand group, thin layers, and oil sand body) are an effective method to conduct vertical heterogeneity reservoir development of downfaulted basins, also one of successful development modes of Daqing Oilfield. In the process of fine reservoir description, the division and contrast of reservoir is more profound and careful because fine stratum model is the foundation of the reservoir microstructure, flow units, reservoir parameters, three-dimensional reservoir geologic model, and reservoir engineering research.

1. Fundamental principle for division and contrast of thin layers

Fluvial and lacustrine facies sedimentation of downfaulted basins presents repetitive superposition phenomenon of different phase belts on the longitudinal profile or multiple sedimentary cycles. There are many factors influencing sedimentary cycles, such as basement rise and fall of basins, change of weather from drought to wetness, change from coldness to hotness, seasonal flood, rise and fall of the lacustrine level, and supply variation of the original sources of sediments. All these can lead to change of rock types and sedimentary facies belt cycles in a certain scope of the basin. This cycle variation always presents four cycles of different scales in a certain scope of an oilfield.

– The first-order cycle: corresponding to an oil-bearing series stably distributed in a tectonic zone or larger scope; made up of source rocks and reservoir rocks, and containing cycle sedimentation of some oil layer groups, generally with micro-palaeobios or obvious lithology mark layers as the cycle boundary.
– The second-order cycle: corresponding to an oil layer group (or sand group), distributed in a local tectonic or an adjacent tectonic structure; made up of reservoir bodies belonging to the same sedimentary system, always with mud interlayers of stable thickness as the boundary.
– The third-order cycle: corresponding to a thin layer (or sand body), stably distributed in local tectonic structures or some fault blocks; generally a reservoir body formed in a sedimentary accident; there existing a mud interlayer up and down the cycle, unstable thickness of the interlayer; very often the minimum sedimentary unit within the scope of sedimentary micro-facies research.
– The fourth-order cycle: a sand layer with variable granularity, or a single-oil layer, corresponding to cyclothem, generally distributed only in a local tectonic structure or a number of fault blocks; the thickness and sedimentary characteristics varying with the phase belt position, stratification, and structure variation.

a. Theory of sequence stratigraphy about fine division of reservoir

Fine division of reservoirs is basically done according to high-precision sequence stratigraphy. Sequence stratigraphy is devoted to the research of the distribution law of cycle lithology sequence in or out of the research zone, with unconformity surface or correspondent conformity surface as the boundary, and with genetic relationship (Wagoner 1988, 1990).

Theoretically, sequence stratigraphy supplies sequence and chronostratigraphic framework of system genetic stratigraphic units, which have close connection with specific sedimentary systems and production of oil and gas and are beneficial to the fine division of source-reservoir-caprock combination and reservoirs, thus laying a solid foundation for reservoir and geological research.

In the process of layer group division and contrast of reservoir description at the high-water cut stage, sequence stratigraphy should be sufficiently applied as the foundation of division of sedimentary cycles and layer groups, and high-resolution sequence stratigraphy theory advocated by Cross should be used to determine the principle for high-resolution division and contrast of sequence and build a reservoir structure model according to the response relationship between the base-level cycle and the sedimentary process.

– Base-level cycle and admissible space. Cross et al. give base-level cycle the meaning of time unit and regard it as a potential energy surface, which reflects the imbalance of the earth's surface and sedimentary process. Sedimentation or erosion effects will continuously change the surface configuration, moving in the direction of the base level. Therefore, the base level always has the tendency of one-way moving to its maximum or minimum range, forming a complete cycle of rise and fall (Fig. 1.2). A base level is isochronous, and the preserved sediment in a changing process of the base-level cycle is a time stratigraphic unit, namely genetic sequence.
– Sediment distribution and phase segregation principle. Sediment distribution means the process in which sediments in the sequence deposit into different phase belts. It is caused by the changes of the base-level and admissible space. During the descent of the base level, the position of effective admissible space migrates and extends to the sea (or the lake) and shrinks from the land, so the coastal sandstone volume gradually increases and the marine rock plain sedimentary volume decreases; during the rise of the base level, the position of effective admissible space migrates to the land, and the space extends to the land, so sedimentary volume that deposits in the coastal plain phase increases (Fig. 1.3). In the long period of the base-level cycle, the progradation sediments that migrate to the basin deposit during the fall of the base level; subsequent vertical aggradational strata form at the rise stage of the base level; retrogradation accumulation styles of migrating to the land appear at the rapid rise stage of the base level.

With the change of admissible space and distribution of sediment volume, phase sequence and phase types in the same sedimentary environment vary greatly, and this phenomenon is called phase segregation.

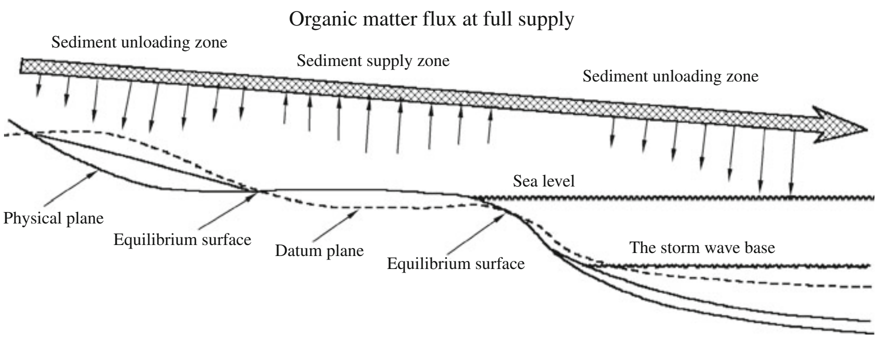


Fig. 1.2 Balance relationship between the base level, accommodation space, and sedimentary supply

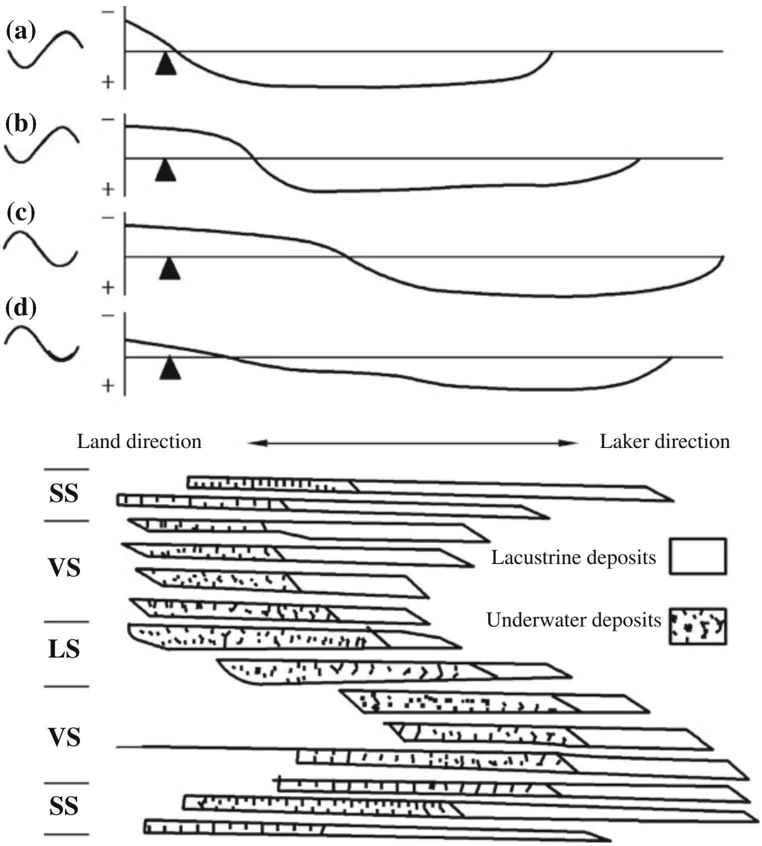


Fig. 1.3 Effective accommodation space migration and sediment accumulation mode

b. Identification of the base level

The base-level cycle can be identified from drilling cores, lithological profiles and logging curves, and the determining sequence interface can be defined according to the superposition styles of the cycles. Identification marks of the cycle interface are as follows,

- Watercourse scour surface and fluvial facies sediment. When the base level descends below the earth's surface, river erosion effect will occur, forming block sandstone and river-stranded deposition. The natural potential and natural gamma present a box type or clock type and have a mutation contact relation with the underlying sediment's logging response (Fig. 1.4).
- Shallow-water sediments directly cover one of the deep waters. It is caused by the sudden decrease of admissible space and the decline of the base level. The deepwater sediments are generally argillaceous sediments, while the shallow-water sediments are relatively coarse sandstone sediments.

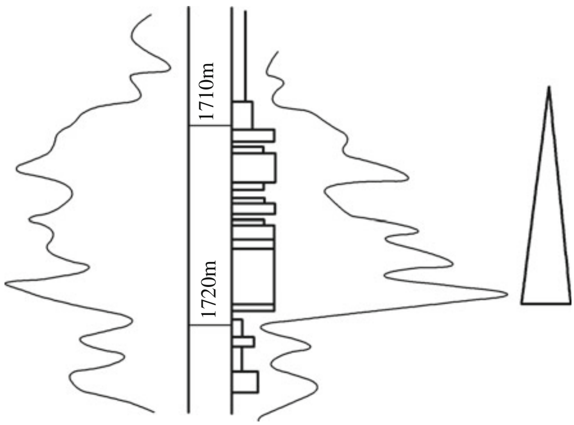


Fig. 1.4 Lithological properties of the base-level rising cycle

– The transformation position of sedimentary facies or facies association on the vertical profile. If the phase sequence which becomes shallow upwards is replaced by that which becomes deep, the position where it takes place is cycle interface. The corresponding electrical logging curve presents conversion of curves combination types, such as funnel type or clock type.
– The position of thickness cycle change of sandstone and mudstone. Under the sequence interface, sandstone granularity becomes coarse and thick upwards, and mudstone's thickness becomes small, while it is the contrary above the sequence interface.
– The original color of mudstone presenting water depth, water body properties, and sedimentary environment is the basis on which to identify the sedimentary cycle. Because mudstone color that becomes light represents that the water body becomes small, the admissible space shrinks, and the base level declines; on the other hand, mudstone color that becomes dark represents that the water body becomes large, the admissible space increases, and the base level rises.

2. Technology and methods of cycle grouping and contrast

According to the high-resolution sequence stratigraphy principle above, the stratigraphic correlation technology, and the methods of cycle correlation and hierarchical control are adopted in single-layer division and contrast. That is the monolayer contrast method under the control of the marker bed.

a. The steps to divide the reservoir set

Reservoir set division and contrast are generally made up of three steps: firstly, starting from core holes and analyzing the sedimentary cycle of the single well; secondly, modifying and unifying preliminary division of each well cycle by repeated comparison in the whole oilfield scope; thirdly, making appropriate adjustments according to geological features of reservoir development and obtaining unifying division and contrast results of development reservoir set.

b. Sedimentary cycle division of the single well

It is as follows, first, to make a sedimentary micro-facies analysis with core holes and then make a sedimentary cycle division; next, to analyze lithology-electricity relation and build logging curves identification features of sedimentary cycle; finally, to divide sedimentary cycle to non-coring wells by the features of logging curves.

The sedimentary cycle division is made by order from big to small, researching the proximate-order division on the basis of the upper-order division. The first-order cycle is generally built at the exploration stage, and at the oilfield development stage, the reservoir is mainly divided into the second, third, and fourth cycle.

- The second-order cycle division. The transformation of different sedimentary facies belt in the first-order cycle is taken as the boundary of the second-order cycle. For example, the lake basin water regression system can be divided into four second-order cycles, respectively: successive sedimentation from the deep lake (lakebed fan) to the shallow lake (delta), to the alluvial plain (river), and to the alluvial fan environment.
- The third-order cycle division. In the fault lake basin, the third-order cycle is generally divided by partial lake transgression with lake transgression mudstone bottom as the boundary, which is the initial stage of lake transgression. Take delta sedimentation as an example, each delta miscellaneous leaf body deposit is formed because of the partial lake transgression and its forward movement.
  Regarding fluvial deposit, one universal flooding event or longer flooding intervals is taken as the third-order cycle boundary, generally with the bottom of the sand layer as the beginning of the flooding event; or periodicity of ancient soil maturity evolution is taken as the division basis of the third-order cycle according to the periodical change of fluvial scale and energy.
- The fourth-order cycle division. The fourth-order cycle is the division of single-sand bodies. For example, in the delta frontal channel mouth bar, the distributive channel sand may be made up of many sand layers whose granularity becomes thick or fine upward, and every sand body formed by abandonment or divagation in rivers is also made up of many sand layers whose granularity becomes fine.
- Using well logging curves to analyze single-well's cycle. The above sedimentary cycle division of coring wells should be the pattern of reservoir layer series division on the field scale. The research on rock–electricity relation and analysis of logging facies are required for the division of the single-well cycle for non-cored wells by using logging curves.

At present, as far as the identification and division of all levels of sedimentary cycle and logging facies on the logging curves are concerned, the cycle analysis is made generally according to lithology combination features reflected by curve shape features. Choosing representative logging curves and acquiring the response to sedimentary cycle are an important content of rock-electricity relation research.

c. Unified division of cycle comparison

On the basis of the single-well cycle analysis, single-well cycle division is adjusted to unify the whole oilfield by the comparison on the field scope. This is a repetitive process until a unified reasonable division and isochronic correlation of all levels of the cycle in the whole oilfield are realized.

– Building the standardized profile and skeleton net. The lithology and thickness of fault basin reservoirs vary greatly. It is of the case that one oilfield spans different fault blocks and sedimentary facies belts. Therefore, standardized profile is built by regions according to different sedimentary types. These standardized profiles are evenly distributed in every section of oilfield, forming the reservoir bed set division and comparison skeleton net. By repetitive comparison, the bed set boundary is reasonably adjusted as the comparison standard for controlling the whole oilfield.
– Determining the standard layer. The accuracy of reservoir comparison largely depends on whether there are standard layers that have evident marks and stable distribution. In the continental basin, the lake invasion mudstone, oil shale, carbonatite, fossil layer, and ancient soil layer can be regarded as standard layers.

The standard layers have evident responding features on logging curves and can be divided into two levels according to the stabilization and distribution scope of standard layers: The first is the time stratigraphic unit within the scope of control tectonic zone; the second is the comparison mark of local structure or auxiliary standard layers.

Distribution stabilization of standard layer in each group is shown by coefficient of stabilization:

$$\text{Coefficient of stabilization} = \frac{\text{the number of wells with standard layers}}{\text{the total number of wells}} \times 100\,\% \tag{1.1}$$

d. Comparison of fluvial reservoir

A fluvial reservoir is very complicated and lacking in standard layers, so making a comparison is very difficult. Here are three summarized methods:

– Using ancient soil maturity to divide and compare the cycles. Ancient soil is produced in the late cycle of the first fluvial sedimentation. Before the next flood comes, the deposited fluvial sediment undergoes weathering and if the weathering is long, the maturity degree of the ancient soil will be big and it is easy to identify. Identifying ancient soil layers can help divide different levels of sedimentary cycles.
– Slice contrast. The fluvial sedimentation between two ancient soil layers is arbitrarily sliced into several layer pieces according to total thickness changing

tendency, equally or unequally. The slice boundary is the contrast isochronal boundary.

– Equal height contrast. The thickness of total sequence sedimentation in the watercourse reflects an ancient river's bankfull depth, the top boundary reflects the bankfull overflow surface, and the top surface of watercourse sediment in the same river is the isochronal surface. On the same watercourse sedimentation, the top surface to standard layer (or one isochronal surface) has nearly equal height. On the contrary, top surface heights of watercourses on different stages are different.

1.2.2 Microscopic Structure Research

Reservoir microstructure does not fall into the structure research scope in the conventional sense. They are formed because of the downcutting of sand body sedimentation, differential compaction and the ancient landform influence, irrelevant to tectonic force (LI Xingguo 1993). The purpose of microstructure research is to illuminate the top and bottom shape of sedimentary units and their influence on and control of the flowing law of oil gas and water (including remaining oil), and thus to instruct remaining oil development.

Microstructures are mainly studied according to drilling data. First, the altitude, bushing elevation and borehole traverse of every well in the research zone need to be rectified, and then the new sublayer correlation results are used to finely define the structural form of the sublayer's top and bottom with the isobath of two meters. With the well pattern and other geological conditions comprehensively taken into consideration, an analysis is made of different microstructures' controlling influence on remaining oil distribution. The following elements are applied comprehensively:

a. the production data of single or combined layers,
b. logging interpretation technology,
c. remaining oil saturation and
d. the inner connection between remaining oil saturation and the concentrating rules of remaining oil predicted by means of numerical reservoir simulation, and the microscopic structure combination.

1. Types, features, and combination patterns of microscopic structure shapes

Microscopic structure forms, such as the high point, nose, slope, low point, and groove, can often be seen on the top and bottom of reservoir units on the regional structure background.

a. Types of reservoir microscopic structure shape

- High point, a type of micro-geomorphic unit that has a relatively high top and bottom type of reservoirs compared with the surrounding terrain, and a closed depth contour. The amplitude difference is generally 2–4 m and the closed area 0.1–0.2 km^2.
- Nose-like structure, a type of micro-geomorphic unit that has a relatively high top and bottom type of reservoirs compared with the surrounding terrain, and an unclosed depth contour generally associated with groove micro-geomorphic units. For example, the nose-like structure units in Gudao East Zone are low and gentle, the dip angle generally less than 3 degrees and the area 0.3–0.4 km^2.
- Low point, a type of micro-geomorphic unit that has a relatively low top and bottom type of reservoirs compared with the surrounding terrain, and a closed depth contour. The amplitude difference is generally 2–4 m, and the closed area 0.2 km^2.
- Groove, a type of micro-geomorphic unit corresponding to the nose-like structure. Its form corresponds to the nose-like structure yet with a reverse direction. It is an unclosed low-lying area.
- Slope terrain, a type of micro-geomorphic unit that develops under the influence of the regional structure background to a greater degree, with its tendency and dip angle in agreement with the regional background.

b. Combination modes of reservoir microstructure

- Top convex and bottom convex (biconvex). Both of the top and bottom surfaces of reservoirs are high points, often caused by river way and delta lens-shaped sand bodies.
- Top convex and bottom flat. The top surface is a relative high point and the bottom surface is smooth or slightly inclined.
- Top flat and bottom convex. The top surface is gentle and the bottom surface is a relative high point.
- Top concave and bottom flat. The top is a low point and the bottom is flat.
- Top and end concave. Both the top and bottom are low points.
- Top and end nose-like convex. The undulate shape of the top and end surface is higher than the surrounding terrain, and the contour is unclosed.
- Bottom flat and top nose-like convex. The bottom surface is flat, and the top is a nose-like convex.
- Top and bottom groove. The undulate shape of the top and end surface is lower than the surrounding terrain, and the contour is unclosed.
- Top flat and bottom groove. The top surface is flat, and the bottom is a groove.

2. The relation between reservoir microstructure combination mode and remaining oil distribution and well production

On the basis of injection-production well pattern, the distance of the injection well and production well, the injected water volume, the injected water streamline, and geological factors considered, some wells with much comparability are chosen to make a contrast and analysis so as to identify the relationship between reservoir microstructure combination mode, and remaining oil distribution and well production.

a. The relationship between microstructure combination mode and remaining oil distribution

By realistic production data verification and numerical simulation forecast, we find that among the microstructure combinations, the top convex and end flat type are remaining oil gathering districts, followed by the top flat and end convex type. The top and end convex type is also the district better than the slope unit between the convex and biconcave type.

b. The relationship between microstructure combination mode and oil production

With the change of water injection development, the influence of microstructure on oil well production is also changing. Under the condition of low water cut, oil production is influenced by all types of microstructure greatly. Under the condition of high water cut, the influence of ultralow and low extent microstructure fluctuation on oil wells is remarkably decreasing and the influence of dynamic factors is remarkably increasing. However, great extent microstructures still exert an influence on oil production.

3. The making of a microstructure graph

The microstructure graph can reveal the heterogeneity of structures and forecast the distribution of remaining oil in the process of development, and it is an important comprehensive technique of water control and oil stability in mature oilfields. The method is to use data of the dense well pattern and small spacing contour line to make a structure bathymetric chart for widespread top or end surface of oil sand layers and the isobath interval is 1–5 m. As for the positive rhythm sand body, to make a graph based on the bottom surface; as for the negative rhythm sand body, to make a graph based on the top surface. The advantage is to show three microstructures of oil layers: the positive direction microstructure (including the small high point, small nose-like structure, small fault nose), the negative direction microstructure (including the small low point, small groove, small fault gutter), and the slope microstructure.

The positive microstructures are generally high production wells and remaining oil gathering districts, the negative microstructures are low production wells and high-water cut well districts, and the other microstructures are between the above two types.

1.2.3 Sedimentary Micro-facies Analysis and Sand Body Connectivity

The heterogeneity of downfaulted basin sandstone accumulation property is very serious. Sedimentary micro-facies research is an important way to exactly know reservoir heterogeneity and the motion law of oil and water in sand bodies. Take injecting water development in the fluvial facies oilfield as an example, the injected water always rushes to the downstream along the main river channel, the sand in the river channel has a positive rhythm and the injected water preferentially rushes into layers with coarse granularity and large permeability on the bottom; river mouth sandbars in the delta facies front edge have a reverse cycle that is coarse at the top and fine at the bottom, and the injected water advances relatively homogeneously under gravity with a big swept volume and high oil displacement efficiency.

1. Sedimentary micro-facies analysis

The sedimentary micro-facies refer to the smallest sedimentological unit, which has special lithology, rock structure, thickness, and rhythm in the sedimentary subfacies. The micro-facies are often used to distinguish genetic types of sand bodies, i.e., those types with special reservoir properties and of the smallest size. For example, in the fluvial sedimentary system, river way, natural barrier and flood fan in the net river belong to micro-facies, and their reservoir properties are quite different. What is more, the sublacustrine fan subfacies can be made up of the river way and interchannel micro-facies, whose reservoirs are of great difference. The common micro-facies in clastic reservoir of continental sedimentary basins are in Table 1.3.

Sedimentary micro-facies research generally includes the division of time units of sedimentary symbol in the research area, single-well facies, logging facies, connected well profile facies, plane facies, on the basis of which facies modes are eventually established, with different focuses according to specific circumstances of oilfields.

a. Single-well facies analysis for the system-cored wells

To observe and describe the core of system-cored wells and other sporadic-cored wells is the foundation of single-well facies analysis. It mainly includes some facies markers such as lithology, sedimentary structure and lebensspur, oil-bearing occurrence (the rich-oil-bearing, oil-bearing, oil immersion, oil spot, oil fluorescence), and structural phenomena such as the physical properties of the rock, crack, fault, and attitude of strata. According to the need of reservoir geological research, some samples should be taken for analysis and test, and on the basis of core location, logging curves, data of oil test, and pilot production, a facies graph of the single well is made to determine the vertical type of sedimentary micro-facies.

Table 1.3 The common micro-facies in clastic reservoirs of continental sedimentary basins

Magnafacies	Subfacies	Micro-facies
Alluvial fan	Fan root	Drainage line, lateral margin river
	Fan middle	Braided channel, middle-channel bar, overflow sedimentation
	Fan edge	Sheet sand
River	Meandering stream	Point bar, natural levee, flood fan, erosion ditch, abandoned channel
	Braided river	Mid-bar channel, abandoned channel
	Anastomosed stream	River way, natural levee, flood fan
Delta	Delta plain	Distributary channel
	Delta front	Estuary dam, inside and outside the front sheet sand
	Prodelta	Sand body undeveloped
Delta near shore		Beach, dam
Sublacustrine fan	Upper fan	Feeder channel, channel between, main channel
	Middle fan	Channel, channel between
	Under the fan	Thin layer of turbidite

b. Logging micro-facies analysis

To presented sedimentary micro-facies types by logging curve forms to analyze sedimentary micro-facies is called logging micro-facies analysis. Qualitatively, different forms of natural potential and natural gamma curves correspond to different phase belts of sand bodies; quantitatively, logging data (stratum apparent resistivity, density, neutron porosity, natural potential and natural gamma) or analysis data (porosity, sandstone percentage composition, sorting coefficient, median size and shale content) at a certain depth is the properties description of the sedimentary facies belt and sediment at that depth. Micro-facies can be relatively well identified according to natural gamma or natural potential curve types, and dip logging.

c. Profile and plane sedimentary micro-facies analysis

Based on the single-well facies analysis, micro-facies types from non-cored wells by logging analysis can be used to analyze the sedimentary micro-facies profile parallel to the along the source direction and along vertical source direction in the research area, and to clarify the change rule of micro-facies and sand bodies.

The sedimentary micro-facies plane figure is an important content of reservoir geology and is the key graph to study reservoir heterogeneity and remaining oil distribution. Generally, based on single-well facies, the sandstone isopach map or sandstone percentage composition equivalent figure at some sedimentary time unit is made, and the same micro-facies distribution is drawn on the plane views.

2. Analysis of sand body connectivity

Sand body connectivity refers to the geometrical morphology, size, connectivity, and space distribution of porosity and permeability of reservoir sandstone bodies, and the heterogeneity caused by space distribution of porosity and permeability. These factors are directly related to the plane influence extent of injected fluid.

The compound sand bodies that are formed when the sand bodies of all genetic units contact each other and are connected vertically and horizontally are called a connective body. According to the connection modes of sand bodies, they can be divided into:

– multilateral type, mainly laterally connected (Fig. 1.5a);
– multilayer or overlap type, vertically connected (Fig. 1.5b);
– isolation type, not connected with other sand bodies (Fig. 1.5c).

The sand body connectivity can be described by the following parameters.

a. Coordination number of sand bodies

The number of sand bodies connected with a sand body is called coordination number of sand bodies. In Fig. 1.6, the coordination number of No. 1 sand body is 1, No. 2 is 2, No. 3 is 4.

b. Degree of connectivity

The proportion of the connected area of two sand bodies to their total area is called connectivity, which is expressed in another way by the proportion of the number of connected wells to the number of control wells in the area of sand bodies.

c. Size of connected bodies

The size of connected bodies is the total area or width of connected bodies.

d. Penetration capacity of sand body contact

Fig. 1.5 Sand body connectivity schematic diagram

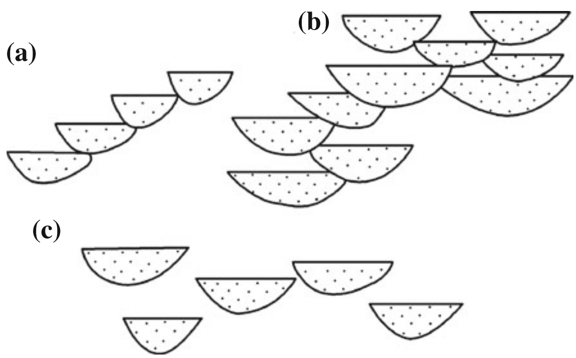
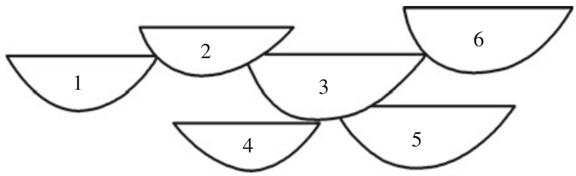


Fig. 1.6 Sand body coordination schematic diagram



With further research on reservoir geology, we find that mutual contact surfaces between sand bodies, including cut flush type of contact connecting surface, are not always the connecting channels of fluids, and it depends on the penetration capacity of contact surfaces. For example, the remaining shell of boulder clay or sand clay gathering on the river way flush surface may be the impervious layers of underlying sand bodies. What is more, if mudstone coating layers exist between sand bodies, impervious, or hyposmosis surface can be formed. In actual work, when geological phenomena of destroying sand body connectivity are found, we can use interference well test to verify it and make a quantitative description. If the permeability of contact surface is high, the sand bodies are connective; if the permeability is low, the connectivity is poor; if the contact surface is impervious, the sand bodies are not connective.

In the research of the connectivity of some type of reservoir sand bodies, besides forecasting its geometric morphology, what is more important is to study its actual sedimentary scale. In continental lacustrine basins, the main transport force of all types of sedimentary bodies is the river and the water body transport capacity of the lake is relatively small. Therefore, in sedimentary basins, it is an important process to forecast the scale of the ancient river in every sedimentary system.

Now a common technology adopted in both China and other countries is using drilling data to forecast the scale of sedimentary sand bodies, that is, using sedimentary phenomena that can be described on two-dimensional profile to forecast the three-dimensional distribution of sand bodies. The common methods include the following:

a. Establishing one-dimensional and three-dimensional empirical formulas of sand bodies with modern sedimentary research achievements;
b. Using the same type of the sedimentary outcrop in this area to measure the actual value and calculate the probability value of sand body scale;
c. Using sand body scale empirical formula or relation graph from dense well condition in the same basin and the same sedimentary environment to forecast the sand body scale of the adjacent development areas in the same basin;
d. Concerning the channel-type-stripped sand body, drilling meeting efficiency method in different well spacing can be used to make an estimate.

After determining the scale and size of all types of micro-facies-sand body generic units, the connectivity and connection modes of the units also need to be analyzed, and the connective sand bodies eventually make up the flowing units in the process of field development in various ways. The continuity of connective bodies is the necessary reservoir property when development decisions are made.

Generally speaking, the permeability direction of fluvial sand bodies and various channel sand bodies should be consistent with the ancient flow direction. The permeability direction of coastal dam sand bodies intensely changed by lake waves is vertical to the ancient flow direction. The identification of regional source direction and carrying direction can control the ancient flow direction at the macro level. Every concrete ancient flow direction of sand bodies may deviate greatly from the total ancient flow direction of the sedimentary volume, and when describing development reservoir, the ancient flow direction in a small extent should be recovered as much as possible.

The basis for judging ancient flow direction:

a. Geometrical morphology of sand bodies;
b. Bedding tendency, according to the bedding plane tendency in the core to make a deduction without orientational coring;
c. Layer dip logging interpretation.

1.2.4 Reservoir Heterogeneity

Reservoir heterogeneity research is the core content of describing and representing reservoirs. The heterogeneity is about the non-uniform change of reservoir space distribution and internal properties under the comprehensive influence of sedimentation, diagenesis, and the late tectonic setting. This non-uniform change can be concretely presented in these aspects: the spatial distribution shape of reservoirs, lithology, and the thickness of reservoirs, the number and thickness of mudstone interlayers, and the properties, pore structure, and fluid quality of reservoir interior.

The change of reservoirs heterogeneity is influenced by many factors. For example, the heterogeneity of continental reservoirs is stronger than that of marine reservoirs. This is because the reservoir of continental sedimentation has poor stability, and its lithology, thickness, and physical properties change greatly. Ninety percentage of discovered reserves by now are from continental sedimentary layers, and most are developed by injecting water, so it is especially important to understand reservoir heterogeneity, which greatly influences reasonable well pattern deployment and oil recovery.

1.3 Reservoir Heterogeneity and Quantitative Characterization

1.3.1 Reservoir Heterogeneity Classification

Reservoir heterogeneity can be divided into fluid heterogeneity and reservoir body heterogeneity. Reservoir heterogeneity can be classified by the scale and cause of heterogeneity, and their influence on the fluid. According to different research purposes, scholars have different classifications. Now the representative classification programs in China and other countries include Pettijohn's classification, Weber's classification, Haldorson's classification, and QIU Yinan's classification.

1. Pettijohn's classification

Pettijohn (1973) put forward a heterogeneity classification diagram from big to small by heterogeneity scale for the fluvial sedimentary reservoir, in which heterogeneity is classified into five scales, including the reservoir, layer, sand body, bedding, and core (Fig. 1.7).

The advantage of this classification is that it is based on sedimentary origin, and easy to find out the origin by combining different sedimentary units. The corresponding relation is as follows:

a. Reservoir scale (1–10 km × 100 m);
b. Layer scale (100 m × 10 m);
c. Sand body scale (1–10 m);
d. Lamina scale (10–100 mm);
e. Core scale (10–100 μm).

2. Weber's classification

According to Pettijohn's classification idea, Weber considered not only the scale of reservoir heterogeneity, but also heterogeneity and its influence on fluid flow, and classified reservoir heterogeneity into seven types.

a. Closed, semiclosed, unclosed fault

This is a structure of large-scale reservoir heterogeneity property, in which the fault's degree of closure has great influence on the fluid flow in a large oil area. If the fault is closed, it cuts off the fluid flow between the fault reservoirs, with a blocking effect, and if the fault is unclosed, it forms a large flow channel.

b. Boundary of genetic units

Genetic units are the sedimentary facies boundary in essence and also the lithology changing boundary. Generally, it is the boundary between the pervious layer and impervious layer, at least the boundary of permeability difference. Therefore, the boundary of genetic units controls large-scale fluid flow.

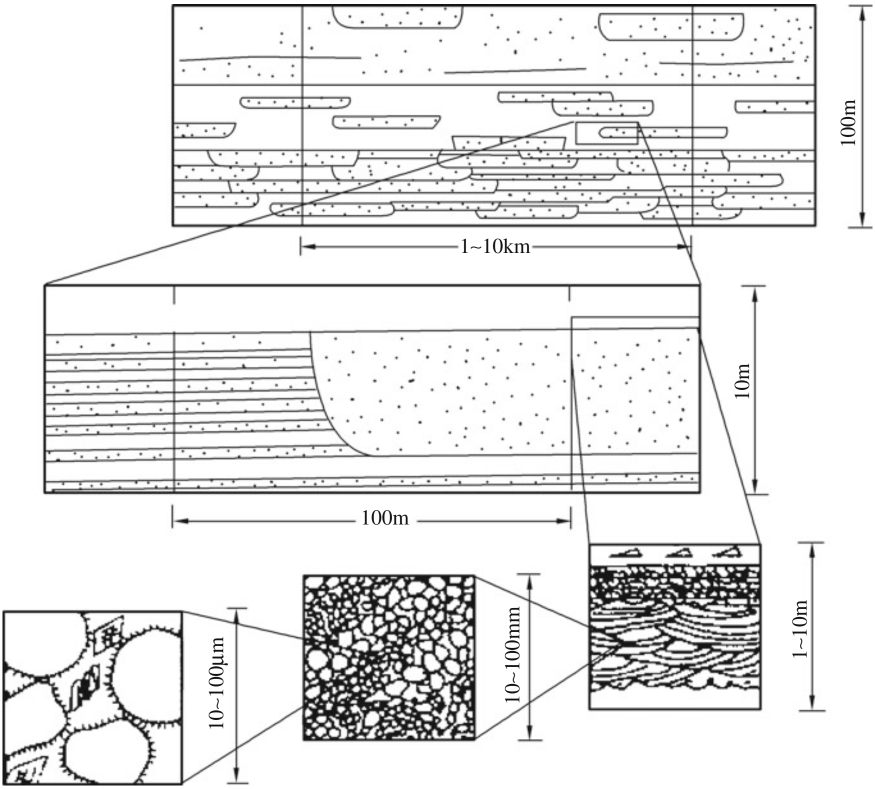


Fig. 1.7 Pettijohn's reservoir heterogeneity classification

c. Pervious layer in the genetic units

In the interior of the genetic units, there are layers of different permeability values, which are distributed like a net in the vertical direction, directly leading to the heterogeneity of reservoir in the vertical direction.

d. Interlayer in the genetic units

Inside the genetic units, fluid flows are greatly different in different scales of interlayers, which influences not only the vertical but also horizontal flow, thus restricting the injection-production interval or the perforation position of field development.

e. Lamina and cross-bedding

As the series of strata inside the bedding structure are evidently different from the direction of lamina, the fluid flow is also influenced greatly, thus directly influencing the distribution of remaining oil after water injection.

f. Micro-heterogeneity

It is the smallest scale heterogeneity. The differences in stone structure and mineral properties lead to the reservoir heterogeneity of core scale.

g. Closed and open fractures

If fractures exist in reservoirs, the closure and openness of fractures can also lead to reservoir heterogeneity.

3. Haldorson's classification

Based on the need of reservoir geological modeling, Haldorson classified heterogeneity into four types (Fig. 1.8).

a. Microcosmic heterogeneity: pore and sand particle scale.
b. Macroscopic heterogeneity: core scale.
c. Mega-heterogeneity: simulating large-scale net blocks of the model.
d. Giant heterogeneity: the whole stratum or region scale.

4. QIU Yinan's classification

Considering continental reservoir properties of China, heterogeneity scale and practicability of production, QIU classified the clastic rocks' heterogeneity into four types from big to small.

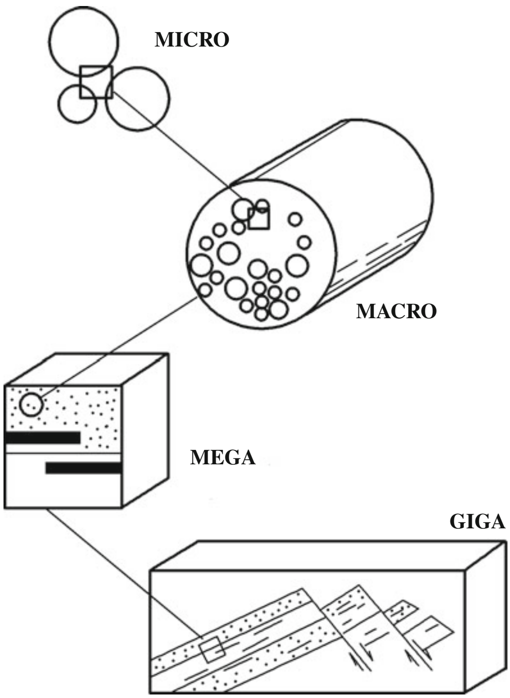


Fig. 1.8 Haldorson's reservoir heterogeneity classification

a. Interlayer heterogeneity, including cyclicity of series of strata, heterogeneity degree of permeability between sand layers, barrier distribution, and special types of layer distribution.
b. Plane heterogeneity, including connectivity degree of sand body genetic units, the change of plane porosity and permeability, heterogeneity degree and direction of permeability.
c. In-layer heterogeneity, including granularity rhythmicity, bedding structure sequence, permeability difference degree and high-permeability position, distribution frequency of the in-layer discontinuous thin muddy interlayer, and other distribution of impervious interlayer and the ratio of horizontal permeability to vertical permeability on the whole layer scale.
d. Pore heterogeneity, which mainly means heterogeneity of microcosmic pore structures, including the sand body pore, throat size and its uniformity coefficient, configuration relation, and connectivity degree of pores and throats.

By synthesizing the results of reservoir heterogeneity researches by scholars in China and other countries, we can classify reservoir heterogeneity into macroscopic and microcosmic heterogeneity. The former includes in-layer heterogeneity, plane heterogeneity and interlayer heterogeneity, and the latter includes pore heterogeneity. The classification is put forward on the basis of considering different reservoir types, and comparing it with other classifications. It is more suitable for the continental reservoir's properties in China, and it is very operable and easy to research and use.

1.3.2 Geological Characteristics of Reservoir Heterogeneity

1. Characterization of interlayer heterogeneity

Interlayer heterogeneity means sand layer heterogeneity in a set of oil-bearing series, i.e., the interlayer difference of the sand body. It belongs to reservoir description of series of strata scale, including the regularity of the alternating occurrence of sand bodies in various sedimentary environments on the profile surface, and the development and distribution law of interlayers. They are analyzed and characterized mainly by the following parameters and methods.

a. Stratification coefficient A_n

The number of sand layers in some layer section, represented by the single-well drilling ratio.

$$A_n = \sum_{i=1}^{n} N_{bi}/\mathrm{n} \tag{1.2}$$

N_{bi} is sand layers number of single well;
N is number of statistics wells.

b. Sand layer density S_n

It refers to the ratio of total thickness of the sand body to that of the strata on the profile. It is also called sand–layer ratio, expressed by percentage.

$$S_n = \frac{\text{total thickness of sand body}}{\text{total thickness of stratum}} \times 100\,\% \tag{1.3}$$

c. Interlayer

The interlayer means the impervious layer which stops the fluid motion in the process of oilfield development, and it is a necessary factor for correctly dividing development series of strata for heterogeneous multilayer oilfields, and carrying out various delamination processing measures. The standards and methods of determining interlayers include:

– Rock types of the interlayer

Generally speaking, the interlayer in clastic rock reservoir is mainly argillaceous rock. Besides pure mudstone, there are some sand-mud types of rock, such as argillaceous siltstone and silty mudstone. Whether the sand-mud stone can be regarded as an interlayer should be based on the core data and the observation of their oil-bearing situation, according to which the oil-free sand-mudstone can be regarded as an interlayer.

– Physical property standard for the interlayer

Determining the interlayer standard by the relation between lithology, physical properties, and oil-bearing features.

a. As for sand-mud rock and mudstone, a certain number of core samples are chosen, respectively, to analyze the physical properties, granularity, and cement content;
b. Respectively drawing cross-plot graphs of permeability with porosity, mud content, calcium content, and granulometric class;
c. Analyzing all types of cross-plot graph and determining the cross-plot closely related to permeability. When the evident inflection point appears on the curve, the corresponding permeability value is the upper limit value of interlayer permeability.

Researching the interlayer boundary with a water driving experiment.

Determining the physical property upper limit value of interlayers with oil production testing. Generally, the physical property lower limit value of the reservoir is adopted as the upper limit value of the interlayer.

Using logging curves to classify interlayers: after determining the lithology and physical property standard for interlayers, we should further study the relation between lithology, physical property, and electrical property in order to determine the interlayer's response and classification standard on logging curves.

Typical curve contrast: finding out the response properties of all types of interlayer stone on logging curves by core observation, and establishing a typical profile according to different rock types; the typical profile surface is used as an evidence to determine the interlayer's lithology.

Quantitative interpretation: in the continuous physical property profile of logging data interpretation, it is cut out by the physical property of the interlayer.

- The thickness standard for interlayers: It is determined by the perforation technical level and borehole operation technical condition. An interlayer whose thickness is smaller than the standard thickness cannot be regarded as an interlayer. Take Daqing Oilfield as an example, the interlayer thickness standard for the series of strata in the early development well pattern is 5 m, becoming 3 m at the times of first encryption adjustment, 1.5–2.0 m at the times of the second encryption adjustment, 3 m when the packer is used to operate in different layers, 1.0–1.5 m at the times of current-limiting fracturing.
- The distribution status of interlayers

Distribution of interlayers on profile: mainly describing the position, lithology, and thickness of interlayers of the reservoir profile studied, which are expressed with a profile map.

Distribution of interlayers on plane: mainly describing the change of interlayer thickness on plane, often expressed with an isopach map, or by distribution frequency of the wells of different thickness levels.

2. Geological properties of interlayer heterogeneity

An oilfield often has many oil layer groups, each of which has many single-oil layers. Interlayer heterogeneity is microcosmic and the lowest level in macroscopic heterogeneity. In an oilfield, interlayer heterogeneity mainly shows some aspects of geological properties as follows.

a. Heterogeneity between reservoir qualities

An oilfield may have many oil-bearing layers vertically, and the qualities between these layers can be greatly different. The differences mainly include the following four types:

- Difference between oil-bearing layers' lithology.

The lithology of oil-bearing layers varies, and layers of nearly any lithology can be oil-bearing layers. If these layers of different types of lithology simultaneously appear vertically in an oilfield, they can generally be distinguished.

- Difference of the oil-bearing space and oil–gas migration pathway

Whatever lithology of the reservoir, the oil-bearing space and fluid flow channels are no more than pores, cracks, holes, and the combination of the three. Regarding every oil layer of the same oilfield, the oil–gas-bearing space and flow channels can be the same type or different types. If they are different, the fluid motion law and original oil–water distribution condition in the pores are different.

– Difference of interlayer permeability

For reservoirs of the same lithology, especially porous sand reservoir, the heterogeneity of interlayer permeability is the most important type of heterogeneity of reservoir physical properties. The difference of interlayer permeability is one of the important criteria for series division and combination in oilfield development.

– Difference of the oil layer thickness

For one single layer, the thickness can be up to meters, even more, but a thin one can be 10 cm, even thinner. In the process of development, because of the gravity difference of oil and water, the development effects of thick and thin layers are very different.

b. Different oil–gas–water relation of each layer

The oil–gas–water relation and the oil–gas–water layers relation of an oilfield are very different. Some are simple, some complex. Even the oilfields with regular oil–gas and oil–water surfaces are different. In reservoirs with complex oil–gas–water layers relation, the water interlayer and gas interlayer are aspects to be considered in oilfield development.

c. Different driving modes and sizes of natural energy between each layer

The natural energy of oilfields generally includes water driving (edge water or bottom water), elastic driving, gas-cap driving, dissolved gas driving, and gravity driving. If different layer positions and regions of one oilfield have different types of natural energy, and their capacities are greatly different, then different development methods should be adopted for different oil layers in order to fully make use of natural energy.

d. Different pressure systems of each layer

The pressure systems of the layers are often different from each other.

The above are four aspects of each layer, which only means there may be four different aspects, not excluding other aspects of difference. In addition, the difference extent of layers of each oilfield varies. Of course, this is not to say that the four aspects of difference definitely exist between layers of each oilfield.

1.3.3 Areal Heterogeneity

Areal heterogeneity means geometrical morphology, scale, continuity of the reservoir sand body, and the heterogeneity caused by the plane change of permeability and porosity in the sand body.

1. Properties of areal heterogeneity

a. Geometrical morphology of the sand body

Geometrical morphology of the sand body is the relative reflection of the sand body direction. The geological description is often classified with the length–width ratio. Generally, the more irregular the sand body is, the higher the heterogeneity.

– Sill-like sand body: The length–width ratio is approximately equal to 1:1, and the plane surface is equiaxed.
– Potato-like sand body: The length–width ratio is less than 3:1.
– Belt-like sand body: The length–width ratio is 3:1–20:1.
– Shoelace-like sand body: The length–width ratio is more than 20:1.
– Irregular sand body: The shape is irregular, and there is a major extension direction.

b. Scale of sand body and continuity in all directions

The key point is to study lateral continuity of the sand body. Generally, if the scale is big and continuity is high, the heterogeneity is small.

– The first level: The sand body extension is more than 2000 m and the continuity is very good.
– The second level: The sand body extension is 1600–2000 m and the continuity is good.
– The third level: The sand body extension is 600–1600 m and the continuity is medium.
– The fourth level: The sand body extension is 300–600 m and the continuity is bad.

The fifth level: The sand body extension is less than 300 m and the continuity is very bad.

In practical studies, it is often expressed by drilling ratio, which reflects the controlling extent of the sand body in certain well spacing density. The higher the drilling ratio, the better the extension.

$$\text{Drilling ratio} = \frac{\text{drilling sand layer well number}}{\text{total well number}} \times 100\,\% \tag{1.4}$$

c. Connectivity of sand body

It refers to the extent to which sand bodies are in contact with and are connected to each other on the surface or in the longitudinal space. It can be expressed with sand body coordination number, degree of connectivity and connectivity factor.

- Sand body coordination number: refers to the number of sand bodies in contact with and connected to a single-sand body.
- Connection degree: refers to the ratio of the connected area of the sand bodies to the total contact area.
- Connectivity factor: refers to the ratio of the number of connected layers of sand bodies to the total number of layers of sand bodies. Connectivity factor can also be expressed in thickness, known as thickness connectivity factor.
- The plane variation and directivity of the porosity and permeability of sand bodies.

The plane variation of sand bodies can be reflected through porosity and permeability contour maps, with the focus on the research of the directivity of permeability.

2. Areal heterogeneity geological characteristics

Reservoir areal heterogeneity is the study of the heterogeneity within the oil and water movement unit. Reservoir plane heterogeneity is mainly displayed in:

a. The areal heterogeneity of reservoir permeability distribution

In any reservoir, even if it is considered the most homogeneous reservoir, different plane positions are different in permeability. Concerning the reservoirs with serious heterogeneity, different areas in the same reservoir are also different in permeability. The difference in areal permeability can be as high as a few times, more than a dozen times, or even dozens of times. In oilfield development, this heterogeneity has become the internal conditions to cause contradictions on the plane.

According to a large number of analyses of reservoirs, reservoirs can be divided into the following five types in terms of plane heterogeneity.

- Widespread distribution of thick oil layers: It is mainly characterized by relatively uniform plane distribution of sand bodies, thick reservoirs, high permeability, with only a few places where the oil layer is missing and small gradient variation of permeability;
- Banded distribution of sand bodies: It refers to the situation that the parts of reservoirs with great thickness correspond to those with high permeability. They are in a zonal distribution, along which there is not much change in thickness or permeability. Besides, they extend far away, perpendicular to the extension direction of sandstone bodies. The reservoirs on the both sides remarkably become poor and even thin out;
- High-permeability zone of scattered reservoirs: The high-permeability zones of this kind of reservoirs are scattered, with large areas of low-permeability reservoirs and pinchout areas;

– Widespread distribution of low-permeability thin reservoirs;
– Scattered oil reservoirs.

b. The influence of stratigraphic dip

Regarding oilfields with both small dip angles and small oil/water density difference, the influence of stratigraphic dip is not big, but for oilfields with big angles, this factor cannot be ignored. The greater the gravity differentiation of the dip angle is, the more apparent the gravity differentiation becomes. When water is injected at the same well point, the displacement effect along the dip to the high part is remarkably different from that along the dip to the low part, thus increasing the influence factors of contradictions on the plane.

c. Reservoir fracture development is uneven.

Cracks are also flow channels of oil and gas in the reservoir in addition to pores. Cracks of different distribution situations play a quite different role in water injection development.

d. Thickness of reservoir plane heterogeneity

Reservoir thickness variation is the prerequisite for non-piston process of water flooding and the role of oil/water density difference. When the thickness is large, gravity presents more apparent effect, which is especially important for the oilfields with bottom water or gas caps.

e. For the same core, different directions are different in permeability.

Whether it is marine sandstone, lacustrine facies sandstone or river delta sandstone, they deposit due to the effect of water flow, with small sand grains of different diameters formed in the process. Due to these factors, coupled by the influence of diagenesis and epigenesis, the permeability of the same rock sample presents different features in different areas. The most prominent case is that parallel bedding permeability is different from vertical bedding permeability. It is called the difference between the parallel bedding permeability and vertical bedding permeability.

1.3.4 In-Layer Heterogeneity

In-layer heterogeneity refers to the qualitative variation in the vertical direction in a single-sand layer, including the degree of permeability differences in the vertical direction in the layer, the location of the high-permeability section, in-layer granularity rhythm, permeability rhythm, the heterogeneous degree of permeability, and the in-layer distribution of thin argillaceous interlayer layers.

1. Characterization of in-layer heterogeneity

a. Particle size rhythm

The clastic particle size variation of the single-sand layer in the vertical direction is called particle size rhythm, which is controlled by the sedimentary environment and sedimentary mode.

- Positive rhythm: The grain size from bottom to top is from coarse to fine, often leading to the fact that the physical property variation from bottom to top is from good to bad.
- Reverse rhythm: The grain size from bottom to top is from fine to coarse, often leading to the fact that the physical property variation from bottom to top is from bad to good.
- Compound rhythm: the combination of positive and reverse rhythm. The superposition of positive rhythms is called positive compound rhythm; the superposition of reverse rhythms is called reverse compound rhythm. If the grains are coarse at the top and bottom, and fine in the middle, it is called positive-reverse compound rhythm.
- Homogeneous rhythm: There is no granularity change in the vertical direction, which is called no rhythm or homogeneous rhythm.

b. Sedimentary structure

In the clastic reservoir, bedding is a common sedimentary structure, including parallel bedding, cross-bedding, oblique bedding, graded bedding, wavy bedding, massive bedding, horizontal bedding. Bedding types are decided by sedimentary environments and flow conditions, and the direction of the bedding decides the direction of permeability. Therefore, we need to study the lithology, occurrence, combination relations, and distribution of all kinds of laminas in order to understand permeability direction.

c. Permeability rhythm

The longitudinal change of permeability is under the control of the rhythm. Different cyclothems are characterized by different permeability rhythms. Like granularity rhythm, permeability rhythm can be divided into positive rhythm, reverse rhythm, and compound rhythm.

d. The ratio of vertical permeability K_v to horizontal permeability K_h (K_v/K_h)

The ratio has a great influence on the water flushing effect in water injection development of reservoirs. The smaller the K_v/K_h, the lower the fluid vertical infiltration capacity and the smaller the layer thickness influenced by water flushing.

e. The degree of permeability heterogeneity (permeability variation coefficient)

Permeability variation coefficient is a concept of mathematical statistics, which reflects the degree of the sample's deviation from the average value. It is the most important parameter for the evaluation of reservoir macroscopic heterogeneity. The greater its value, the more serious the reservoir macroscopic heterogeneity.

f. The distribution frequency and distribution density of argillaceous interlayers

The distribution of argillaceous interlayers is not stable, so it can cause permeability change in reservoir sections in both the vertical and horizontal directions.

– The frequency distribution of the interlayer P_k: the number of argillaceous interlayers in a meter of the reservoir.

$$P_k = \frac{N}{H} \tag{1.5}$$

P_k is interlayer distribution frequency, each/m;
N is the number of impermeable interlayers within the layer;
H is layer thickness, m.

– Interlayer distribution density D_k: the thickness of argillaceous interlayers per meter in the reservoir.

$$D_k = \frac{H_{sh}}{H} \tag{1.6}$$

D_k is interlayer distribution density, m;
H_{sh} is the total thickness of argillaceous interlayers in the reservoir, m;
H is layer thickness, m.

2. Geological characteristics of in-layer heterogeneity

In-layer heterogeneity is remarkably characterized by:

a. A large number of coring well data show that the permeability distribution is greatly uneven in the same reservoir in the vertical direction. According to the characteristics of longitudinal change of reservoir permeability, reservoirs can be divided into the following types:

Homogeneous reservoir: The longitudinal change of reservoir permeability is not big and its regularity is not obvious, either;

Positive rhythm reservoir: a reservoir in which permeability is high at the bottom and it becomes low upward progressively;

Reverse rhythm reservoir: a reservoir in which permeability is low at the top and it becomes high upward progressively;

Full rhythm reservoir: a reservoir in which permeability changes gradually from high to low and then to high from bottom to top, or the permeability changes gradually from low to high and then to low from bottom to top;

Compound rhythm reservoirs: a reservoir in which permeability changes from high to low or from low to high repeatedly, which forms lamination in a reservoir;

No rhythm reservoirs: a reservoir in which the longitudinal change of reservoir permeability is irregular or in the form of steps.

b. A single thick reservoir can be subdivided into several segments due to the presence of the interlayers of different lithological and physical properties. In the development of thick oil layers, these interlayers play a very important role in the oil–water movement rule and the duration of the effectiveness of development measures. The longer the interlayer extends, the better the results of the measures taken. Therefore, in a sense, the interlayer and its extension are more important than the reservoir itself.

The interlayers in a thick oil layer can be divided into several types:

a. Thick oil layers with stable interlayers, which refers to the interlayer whose extension distance can reach more than one injection-production well spacing, as shown in Interlayer 1 in Fig. 1.9a;
b. Thick oil layers with relatively stable interlayers, which refers to the interlayer whose extension distance can reach half of the injection-production well spacing, or even more, but less than a well spacing, as shown in Interlayer 2 in Fig. 1.9a.
c. No stable interlayers in the thick oil layer, which refers to the interlayer whose extension distance is less than half of an injection-production well spacing. The mudstone layers or low-permeable formations are distributed in the form of lens

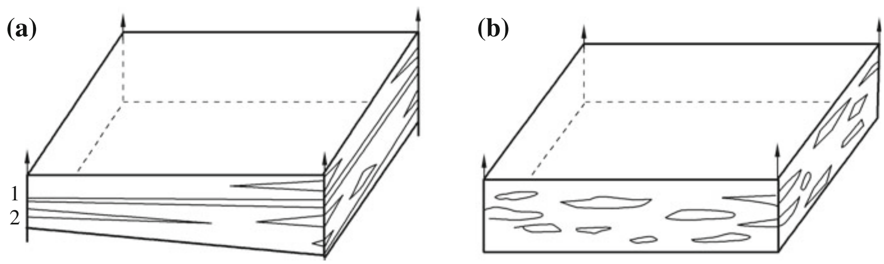


Fig. 1.9 The type of interlayers in thick reservoirs

in sandstone. Where the number of the lenticels is great and they overlap each other, they will exert a significant influence on the oil–water movement, as shown in Fig. 1.9b.

1.3.5 Micro-heterogeneity

1. The concept of reservoir micro-heterogeneity

Reservoir micro-heterogeneity refers to the geologic heterogeneity which influences the fluid flow in micropores and channels, mainly including the volume, distribution, configuration and connectivity of pores and throats, as well as the rock composition, grain arrangement mode, matrix content, and cement type. Any reservoir pores consist of pores of various diameters. Permeability depends on the dimensions of pores and throats. There may be an interpore interference if the discrepancy is remarkable. In particular, when the pores and channels are big, the fluid will flow through them and the small ones may be closed. The research of the oil layer heterogeneity is regarded as the basis for understanding water flooding performance and residual oil distribution.

2. The geologic features of micro-heterogeneity

Water, oil, and gas are restored in the pores and cracks, within which they flow. The following are the bases for researching their movement rule and improving oil recovery: the number of the pores, the volume of the pores, and the diameters of the pores. Porosity is used to express the ratio of pore volume (including fracture volume) in rocks to the total rock volume. The equation is as follows:

$$\text{Porosity} = \frac{\text{pore volume}}{\text{rock volume}} \times 100\,\% \tag{1.7}$$

The ratio of total pore volume to total rock volume is called absolute porosity or total porosity and it contains all the rock pores and cracks, whether they are connected or not. In researching the oil layer, the stressed point is connection porosity, or in other words, the ratio of valid pore volume to total rock volume.

a. Performance of the oil layer pore heterogeneity

Performances of the oil layer pore heterogeneity are as follows:

– Any sandstone pores consist of pores of various diameters.

Permeability varies with different pore diameters. Pores of different radiuses themselves mean permeability heterogeneity.

– The interpore connection performance varies.

Pores and their connection with other pores are different from each other. When a pore is connected with other pores only in one direction, the water flooding can hardly reach it. Only if there are more than two directions connected is water flooding likely to reach it. Then, the pore is called a water–oil displacement pore. If a pore is connected in more than three directions, it is called a multi-directional open pore. The oil displacement effects vary with the number of directions in which pores are connected as well.

– The complexity of oil layer pore shapes

The complexity of pore shapes leads to the difference in distribution of initial water and oil between different pores, which in turn leads to the difference in oil displacement performance. Although the difference is small, it cannot be ignored. Even when these pores are connected by throats to become a pore network, an individual pore has its own complex form, which constitutes the complexity of the water–oil displacement process.

b. A few factors that influence pore heterogeneity

Pores are the gaps between rocks or holes in rocks. Therefore, pore parameters (including porosity and median pore radius) are closely related with rock grains.

– The bigger the rock grains, the bigger the pores.
– The smaller the rock grain diameters, the larger the number of pores and the surface areas of the grains.
– If the median grain diameters are equal, the well-sorted sandstone pores are relatively uniform in granularity and are larger than the poorly sorted ones.
– Pores are influenced by clay minerals in more than one way, which is left for other discussions.

1.3.6 Quantitative Features of Reservoir Heterogeneity

Through the comprehensive geologic functions of sediment, diagenesis, tectogenesis, and so on, there are enormous changes for the interior of the reservoir and the space arrangement of corresponding property parameters. This change is defined as reservoir heterogeneity. It influences the movement rule of underground oil, gas, and water and controls the distribution of remaining oil. Based on this, a macroscopic and microscopic analysis is made of the quantitative features of reservoir heterogeneity, respectively, in the following.

1. Quantitative features of micro-heterogeneity

Reservoir micro-heterogeneity refers to the volume and degree of uniformity of pores and throats in the sand body, the configuration relationship between pores and throats and their connectivity. It has a direct effect on the micro-efficiency of water flooding and controls the distribution of micro-residual oil. We can make use of different experiment methods for the parameter of rock pore structure, and according to different emphatic prospects, it can be divided into three types: parameter of the volume of characteristic pores and throats, parameter of their sorting features, and parameter of their connectivity.

a. Parameter of the volume of characteristic pores and throats

- Pore-throat radius and the distribution of pore-throat volumes: Usually, the biggest sphere radius that can go through the pores and throats is defined as pore-throat radius. The distribution of pore-throat volumes refers to the throat diameter and the percentage of total pore volume taken up by the pore volume controlled by the throats.
- Displacement pressure (P_d) and the maximum pore-throat radius (R_d): The minimum pressure required for non-wetting-phase fluid to begin to enter rock pores or the minimum pressure required for the wetting-phase fluid to begin to be displaced in the biggest connected pores and throats of the rock is defined as displacement pressure. The corresponding pore-throat radius is called the biggest pore-throat radius.
- Median capillary pressure (P_{c50}): refers to the corresponding capillary pressure value when mercury saturation is 50 % on the displacement capillary pressure curve. The smaller the P_{c50} value, the better the permeability of the rock.
- Median pore radius (R_{50}): is the corresponding throat radius when the invading mercury saturation is 50 %.
- The mean value of the main stream pore-throat radius (R_z): refers to the average value of the pore-throat radius whose contribution to permeability value is up to more than 95 %. The greater the value, the better the reservoir physical properties.

$$R_z = \frac{\sum_{i=1}^{n} r_i \Delta K_i}{\sum_{i=1}^{n} \Delta K_i} \tag{1.8}$$

r_i is interval throat radius, μm;
ΔK_i is interval permeability contribution value, $1 \times 10^{-3} \mu m^2$;
n is the number of the pore-throat interval whose total permeability contribution value reaches 95 %

b. Parameter of the sorting features of characteristic pores and throats

- The sorting coefficient of pores and throats (S_p): used to describe the uniformity degree of pores and throats, whose empirical equation is as follows:

$$S_p = \frac{D_{84} - D_{16}}{4} + \frac{D_{95} - D_5}{6.6} \tag{1.9}$$

$D_x (x = 1, 2, \ldots)$ is the pore-throat radius when the invading mercury saturation is x %.

The smaller the S_p, the better the pore-throat uniformity and the better the sorting, too.

Pore-throat skewness degree (S_{kp}): used to measure the non-normal characteristics of pore-throat frequency curve, whose empirical formula is:

$$S_{kp} = \frac{D_{84} + D_{16} - 2D_{50}}{2(D_{84} - D_{16})} + \frac{(D_{95} + D_5 - 2D_{50})}{2(D_{95} - D_5)} \tag{1.10}$$

– Pore-throat kurtosis (k_p): used to reflect the acuity degree of the frequency curve of throat distribution, whose empirical formula is:

$$k_p = \frac{D_{95} - D_5}{2.44(D_{75} - D_{25})} \tag{1.11}$$

The larger the k_p is, the weaker the heterogeneity is, which shows pores and throats are concentrated in a small scope of a certain radius.

– The peak number of pore-throat distribution (N), peak value (X), and peak position (R_v)

Peak number (N): refers to the number of peaks on the frequency curve of pores and throats;

Peak value (X): refers to the volume percentage of the pore-throat radius which takes up the highest volume percentage of pores and throats.

Peak location (R_v): refers to the pore-throat radius that corresponds to the peak value of pore-throat distribution.

– Uniformity coefficient (α): Each throat-channel radius (r_i) in the characteristic rock samples may deviate from the maximum throat-channel radius ($r_{\max}$) to some extent. Uniformity coefficient refers to the weighing of such an extent to the mercury saturation.

$$\alpha = \frac{\sum_{i=1}^{n} \frac{r_i}{r_{\max}} \cdot \Delta S_i}{\sum_{i=1}^{n} \Delta S_i} \tag{1.12}$$

r_i is a certain pore-throat radius of the pore-throat radius distribution function;
$r_{\max}$ is maximum pore-throat radius;
ΔS_i corresponds to the mercury saturation of r_i in a certain interval

α ranges from 0 to 1. The bigger the α is, the more uniform the pore-throat distribution is.

c. Parameter of the connectivity of characteristic pores and throats

   - Mercury withdrawal efficiency (W_e): It refers to the ratio of the volume of the mercury ejected from the rock sample when the pressure drops from the maximum to the minimum to the total volume of injected mercury at the maximum pressure. This value reflects the recovery of the capillary effect of non-wetting phase.

$$W_e = \frac{S_{\max} - S_r}{S_{\max}} \times 100\,\% \tag{1.13}$$

$S_{\max}$ is accumulated mercury saturation at the maximum pressure in the experiment;
S_r is mercury saturation in the pores at the end of the mercury withdrawal;
W_e is the efficiency of the mercury withdrawal.

- The percentage of the minimum volume of unsaturated pores and throats ($S_{\min}$): It refers to the percentage of the total volume of the pores and throats uninvaded by mercury when the mercury is injected into the rock sample at the highest working pressure. The bigger the $S_{\min}$ is, the bigger the total volume of the pores and throats in the rock.
- Tortuosity (L): It refers to bending degree of throats, which reflects the pore-throat connectivity and complexity. The bigger the tortuosity and the more complex the pore structure, the lower the corresponding oil displacement efficiency.
- Pore-throat coordination number: It refers to the number of throats that connect each pore. It is a measurement of the connectivity of the pore system. In a single hexagonal network, the coordination number is 3; in triple hexagon networks, it is 6.
- Pore tortuosity (bending coefficient): It refers to the ratio of the distance between two points along the open pores to the linear distance between the two points. It is the characteristic of pore structure in the one-dimensional space. It is expressed with the formula:

$$T = \frac{L_{\text{eff}}}{L} \tag{1.14}$$

T is tortuosity factor;
L_{eff} is the distance between two points along the open pores;
L is the linear distance between the two points.

The closer to 1 the sinuosity is, the better it is for the fluid flow, for the resistance is smallest in the process of fluid flow influenced by the sinuosity in the channels.

– Apparent pore-throat volume ratio (V_R): used to measure the values of pore volume and throat volume, which is expressed with the formula:

$$V_R = \frac{\text{mercury injection rate} - \text{mercury dropout rate}}{\text{mercury withdrawal rate}} \times 100\,\% \tag{1.15}$$

– The structure uniformity (αW_e): used to reflect the characteristics of invading mercury curve and mercury withdrawal curve. It is the characterization of the degree of uniformity and connectivity of the pore structure.

2. Quantitative features of macroscopic heterogeneity

The common research method is to make a quantitative assessment of reservoir macroscopic heterogeneity by making use of the parameters: permeability variation coefficient (V_k), permeability mutation coefficient (T_k), permeability ratio (J_k), etc.

a. Permeability variation coefficient V_k: it is a concept of mathematical statistics, reflecting the deviation extent to which the sample deviates from the mean value of the total. It is the most vital parameter for assessing the reservoir macroscopic heterogeneity. The bigger the value, the more severe the macroscopic heterogeneity of the reservoir.

$$V_k = \frac{\sqrt{\sum_{i=1}^{n} (K_i - \overline{K})^2}}{\overline{K}} \tag{1.16}$$

V_k is Permeability variation coefficient;
K_i is permeability value of a certain sample in the layer, $i = 1, 2, 3, \ldots, n$;
K is mean permeability value of a certain sample in the layer, $10^{-3}\ \mu m^2$;
n is the number of samples in the layer.

Generally, when $V_k < 0.5$, it is the type of homogeneous; when $0.5 < V_k < 0.7$, it is the type of relatively homogeneous; and when $V_k > 0.7$, it is the type of nonhomogeneity.

b. Permeability mutation coefficient T_k: reflects the ratio of the maximum permeability of the sand layer to the average permeability of the sand layer.

$$T_k = \frac{K_{\max}}{\overline{K}} \tag{1.17}$$

T_k is darting permeability coefficient;
$T_{\max}$ is maximum permeability of the layer, $1 \times 10^{-3}\ \mu m^2$

Generally, when $T_k < 2$, it is the type of homogeneous; when $2 < T_k < 3$, it is the type of relative homogeneous; and when $T_k > 3$, it is the type of nonhomogeneity.

c. Permeability ratio J_k: the ratio of the maximum permeability to the minimum permeability.

$$J_k = \frac{K_{\max}}{K_{\min}} \tag{1.18}$$

J_k is permeability ratio;
$K_{\max}$, $K_{\min}$ are minimum and maximum permeability in the sand layer, $1 \times 10^{-3}\ \mu m^2$

The bigger the permeability ratio, the greater the permeability heterogeneity; the smaller the permeability ratio, the weaker the permeability heterogeneity.

d. Permeability homogeneity coefficient K_p

$$K_p = \frac{\overline{K}}{K_{\max}} \tag{1.19}$$

Obviously, the smaller the K_p is and the closer to 1 it is, the better the homogeneity is.

e. Distribution frequency and distribution density of the argillaceous interlayer

An intraformational bed is generally located in the impermeable layers or layers of low permeability in the single-sand layer. Its thickness varies from a few centimeters to tens of centimeters, generally mudstone, silty mudstone, or calcareous sandstone. The intraformational bed is caused by the change of transient and local water flow, which reflects the micro-facies or phase transition of the sand body, so its shape and distribution are unstable. And the instability of the argillaceous interlayer functions as a barrier to the flow due to its impermeability or extremely low permeability and influences the change of permeability in the vertical and horizontal direction. Mainly influenced by the sedimentary environment (Fig. 1.10), its distribution and lateral continuity take on randomness and are difficult to track. However, it can be predicted through the analysis of the sedimentary environment. The following two parameters are often used to describe the distribution characteristics of the argillaceous interlayer.

– interlayer distribution frequency (P_k):

It refers to the number of argillaceous interlayers per unit thickness of the reservoir.

$$P_k = N/H \tag{1.20}$$

N is the number of impermeable interlayers;
H is layer thickness, m.

– interlayer distribution density (D_k)

It refers to the thickness of impermeable interlayer per unit thickness of the argillaceous interlayer, i.e., the ratio of the total thickness of the interlayers to that of the reservoir.

$$D_k = H_{sh}/H \times 100\,\% \tag{1.21}$$

H_{sh} is the total thickness of impermeable argillaceous interlayers, m;
H is reservoir thickness, m.

The plane contour map of the above two parameters can reflect the distribution of the interlayer on the plane. The role of interlayers in the development of oilfields is a barrier:

– The existence of the interlayer makes the anisotropism of the reservoir permeability more obvious;
– The distribution of the interlayer has an effect on the oil and water movement law;

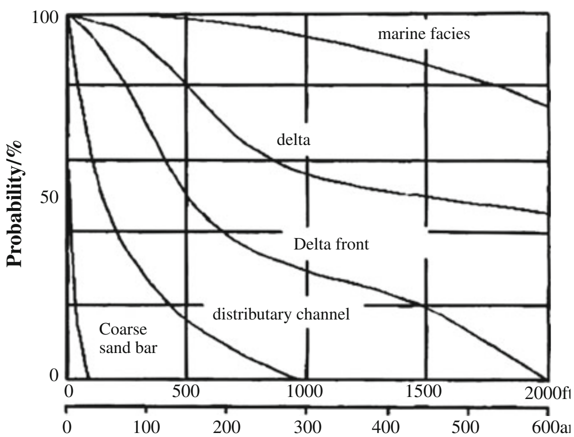


Fig. 1.10 The continuity of the shale (silt) interlayer is the function of sedimentary circumstance

Table 1.4 Classification standard for reservoir heterogeneity

Heterogeneity types	Variation coefficient (V_k)	Mutation coefficient (T_k)	Ratio (J_k)
Homogeneity type	<0.5	<2	<2
Relative homogeneity type	0.5–0.7	2–3	2–6
Heterogeneity type	>0.7	>3	>6

– The stability of interlayer distribution influences the pressure distribution in thick oil layers.

Generally speaking, the bigger the V_k, T_k, and J_k, the stronger the heterogeneity; the smaller the V_k, T_k, and J_k, the weaker the heterogeneity. The reservoir heterogeneity of clastic rocks classification standard in China is usually adopted as follows (Table 1.4).

1.4 Influence of Reservoir Heterogeneity on the Development Effect and Well Pattern

The degree of reservoir heterogeneity has a great impact on water-flooding efficiency, and the development effect and benefits. It plays a vital part in the understanding of development effect and functions as a great reference to the evaluation of reservoir exploitation and the adjustment of oilfield development.

1.4.1 Influence of Longitudinal Heterogeneity on the Development

Interlayer heterogeneity is the internal cause of longitudinal heterogeneity (also termed as interlayer discrepancy), and the external cause lies in multilayer commingled production and commingled injection, or unreasonable water injection and oil production. In the water injection well of multilayer commingled injection where the pressure is equal, the absorption ability per unit thickness in each layer varies largely, and the start-up pressure difference varies as water is injected into different oil layers. Different layers in a producer well are greatly different in oil production and pressure difference. Since there is usually remarkable discrepancy between each layer in a well, the good layers absorb more water and produce more oil with rapidly advancing waterline; the bad ones absorb less water and produce less oil with slowly advancing waterline. Therefore, the longitudinal heterogeneity leads to the phenomenon of water excessively advancing along a single layer, which causes a small volumetric sweep efficiency of the water flooding. Hence, it is necessary to understand heterogeneity, choose reasonable layers for injection, and enhance the water-flooding efficiency as much as possible so that the recovery could be improved through water flooding.

1. The oil well interlayer interference in the production

   a. Working system of oil wells: when the working system is changed, the percentage of production in each layer changes as well. As the pressure difference rises and flow pressure declines, the proportion of the production of low-yield layers begin to increase; as the pressure difference declines and flow pressure rises, the proportion of the production of high-yield layers begin to increase. As breakthrough happens and the pressure of the breakthrough interval is higher than that of the others, the production pressure difference rises, the flow pressure decreases, and the water cut of the whole well declines; as the pressure of the breakthrough interval is lower than that of the others, the production pressure difference rises, the flow pressure decreases, and the water cut of the whole well increases.
   b. Flowing backward phenomenon: it is common in the water flooding exploitation of oilfields, especially when the water cut is high. The effects of flowing backward on the exploitation can be concluded from the following two parts:

      – The misjudgment of the oil–water interval. When there is wellbore flowing backward, most probably the water of the breakthrough interval pours into the low-pressure reservoir, which will form an aqueous envelope near the wellbore. To find water through stratification testing, often only the water containing condition of the zone near the wellbore will be detected. As a result, it is likely to cause misjudgement of the oil–water interval and the detection of a wrong layer in spite of the stratification testing, which leads to the failure of the expected goal and even losses.
      – The downsizing of production. When the water flows backward from the high-pressure aqueous layer into the reservoir, the well water cut rises and oil production decreases obviously.

   c. Well killing: It is the usual procedure in the underground work of oilfields. Owing to different interlayer pressures, some new problems are emerging. “Leakage before well blowout” refers to the fact that after the well killing, it works and the leakage happens. As the liquid surface drops to a certain degree, ejection happens. Since the low pressure of some layers leads to the leakage, the liquid level drops. When the liquid level drops to a certain degree and the high-pressure layer’s pressure is higher than the liquid cylinder’s, leakage happens and the low-pressure layer is leaking at the same time. When the well is reopened after well killing, all layers are contaminated by the well control fluid to different degrees because the pressures of these layers are different. The high-pressure layer suffers slight contamination, but the contamination of low-pressure layers is serious.

d. Drilling infill and adjustment wells. Because the pressures of separate layers are different, some of the layer pressures are several MPa higher than the initial pressure, and it leads to high density of drilling liquid, drilling jamming, and bad well cementation. More seriously, the low-pressure layers may be seriously contaminated, which causes low production of adjustment wells.
e. Owing to interlayer interference, the performance of production fluid in each oil layer varies. Water flooding is not effective to all layers, to say nothing of the same effectiveness to each of them. It has a high effect on some layers, a low or medium effect on some others, and no effect on the rest.
f. The interlayer interference accelerates the water content. High water content is an enormous menace to high and stable oil production.

In a nutshell, heterogeneity is characterized by different producing degree of oil layers. In particular, under the condition of multilayer commingled production, some layers are low-producing or non-producing at all. This greatly affects the recovery of the whole oilfield, usually with a production decrease from 5 to 10 %.

2. The effect of interlayer discrepancy on development effect

Interlayer discrepancy is the result of the interlayer interference and monolayer breakthrough, which is remarkably characterized by the decrease of recovery factor, exploitative economic performance, and production of oil wells and water injection wells. They are related to each other and have their respective characteristics as well.

a. The effect of interlayer discrepancy on recovery factor

   – The exploitative degree of oil layers and interlayer interference extent

The effects of interlayer discrepancy on recovery are a small number of utilized layers and small drown thickness. Under the condition of multilayer commingled production, both of the factors can cause very poor exploitative conditions or no exploitative conditions in some layers.

The first cause of the fact is that the injection and production system is not good enough: either there are no oil production wells or no water injection wells. As to some oil layers, there are too many water injection wells and not enough production wells, or vice versa. The system is so bad that the development effect is unsatisfying. This is mainly due to the unreasonable well pattern arrangement, and it is necessary to improve the infill well pattern.

The second cause is that in spite of the relatively perfect injection and production system, the reasonable well arrangement, and a certain capability of water absorption and oil recovery, these oil layers do not work well or do not work at all because of the interlayer interference.

– The effect degree of interlayer discrepancy on recovery

We usually judge the effect degree according to the number of exploitative layers in a well pattern, the thickness, and interlayer permeability discrepancy. Generally speaking, the larger the number of layers, the bigger the thickness and the bigger the discrepancy, then the larger the effect degree on recovery.

b. The effects of interlayer discrepancy on reservoir production capacity

For the multilayer well, the effect is remarkable.

– The oil production of several well-behaved multilayers is far lower than the sum produced by way of monolayer production. Once several ideal and homogeneous oil layers are penetrated, the sum of production calculated through stratification testing is bigger than the amount of oil produced through multilayer commingled production.
– for the high-water injection well, the sum of the injected water of the single layers per day is higher than that of the commingled multilayers.
– Varieties of interlayer interference can reduce the production capacity under certain conditions: for example, flowing backward causes contamination of the oil layers near the bottom hole by water; the phenomenon "leakage before well blowout" can also cause the contamination of oil layers; when the adjustment well is drilled, the use of high-density drilling fluid due to high-pressure subzones can cause the contamination of low-pressure oil layers as well.

3. The effect of interlayers on development effect

The distribution of interlayers in the injection-production well group exerts great influence on the oil and water movement and development effect. Sandstones of identical genetic types have similar permeability. Whether interlayers are developed and how different they are in development degree often lead to different development effects. In thick oil layers without or with only a few interlayers, the average water content is relatively high and oil saturation is relatively low. On the contrary, in thick oil layers with well-developed interlayers, the average water content is relatively low and oil saturation is relatively high. It illustrates that the oil wells with well-developed interlayers have relatively poor development effect and there is relatively enriched remaining oil in them.

Even in sand dam micro-facies of relatively great thickness in a delta, the average residual oil saturation in thick oil layers is relatively high because of a large number of thin interlayers, which reduce reservoir connectivity and the degree of water flushing. All in all, in the injection-production well group with unstable distribution of interlayers, bottom-hole water flushing is still adopted and the water flooding thickness is small. If interlayers are distributed stably, it is easy to form multiple-stage flooding and great water flooding thickness.

In general, as long as there are relatively stably distributed interlayers in the injection-production well group, they can function as a barrier to oil and water. An oil layer can be divided into two independent oil–water movement units. Then, the intraformational problems in the thick oil layer become interformational problems, and the existence of the stable interlayers enables the watered-out characteristics within the two layers, upper and lower, to conform to the sedimentary characteristics of the respective subzones. If interlayers are distributed unstably, then the top and the bottom of the oil layer are associated hydrodynamically, generally characterized by injection water channeling. The more unstable interlayers, the more complex the oil and water movements and their distribution. Therefore, in the presence of unstable interlayers has great influence on development effect. The more the unstable interlayers, the worse the oilfield development effect.

1.4.2 Influence of Areal Heterogeneity on the Oilfield Development

On the plane, injected water always lunges forward along the high-permeability zone. Due to the large distribution scope of the reservoir, each reservoir is generally equipped with more than one injection well and one production well, but in fact there are a lot of such wells. Naturally, there appears a problem of relationship between the wells, which is revealed by plane discrepancy, for example. The cause of plane discrepancy is heterogeneity on the same reservoir plane, mainly reservoir lithologic heterogeneity.

1. The main forms of plane discrepancy in the production

   a. Interwell interference

It is a kind of pressure interference between the wells in the same oil layer, which is familiar to oilfield development workers. Interwell interference relationship can be divided into three types: between water injection wells, between producing wells, and between the above two types of wells. The pressure interference relationship between injection wells and producing wells is theoretical basis for the effectiveness of water-flooding oilfields. Only the interference between water injection wells and between producing wells is discussed here.

The interference between producing wells. Decades of development practice has proved that the increase of new wells in the same production position will reduce the old wells' production. The smaller the well spacing, the more the decrease of high-permeability reservoirs. This phenomenon is called interwell interference.

Under the condition of hydraulic drive, the new wells drilled in different positions have different influences on the old wells. This is because the energy production and supply of liquid mainly come from the injection wells. If the new well is located on the mainstream line between the injection well and the old production well, the old well's production will significantly decrease due to the effect of the pressure release of the new well. Under the condition of monolayer water injection, if water injection volume remains the same, the production of the new well is roughly the same as the production decline of the old well. If the new well is located with the same distance from the injection well as the old production well's with the injection well in between, the new well has some influence on the old well, but it is much smaller. If the new well is located beyond the area controlled by the flow line between the old production well and the injection well, the new well still has some effect on the old well, but it is even smaller.

There are two purposes of studying interwell interference. One is to choose the reasonable oil well spacing, which should be given different stresses on different ways of development. It is very important to the oilfields which use elastic drive and dissolved gas drive, but less important to those using hydraulic drive with the line-drive pattern. The other purpose is to choose the reasonable infill well location.

The interference between water injection wells. Like production wells, injection wells are faced with interwell interference problems. If the increased injection volume of the new injection well is only a little more than the decreased volume of the adjacent old well, then drilling a new injection well is not reasonable.

b. Interwell discrepancy

The oil wells located in different directions in the same injection well group are different in formation condition, water out behavior, and pressure. Therefore, for the same injection well, the reasonable water injection rate should be adjusted according to the above factors to keep the pressure, stabilize the production, and control the increasing speed of water cut, thus causing the plane discrepancy in injection allocation. This situation is ubiquitous in the line-drive well pattern and areal well pattern, and it is more outstanding in the latter case, unless there is only one injection well and one production well in the sand body.

Different oil wells influenced by the same injection well need a different injection allocation, which requires that the majority of the wells be focused on and the water injection rate of high-yield wells be reasonable and accurate. To the wells which are not taken sufficient care of or even neglected in this aspect, some measures should be taken on the oil wells or some other work should be done on other injection wells that have influence on these wells to achieve reasonable development.

c. Discrepancy of producing well row beside the line-drive water injection well pattern and row

Such discrepancy is caused by different row spacings between the injection well row and the production well row beside it, i.e., the problem of "over-flooding to some wells and under-flooding to some others," or by oil layer heterogeneity. The water cut of the production wells on the one side of injections wells is rising too rapidly and requires less water injection from the injection wells, but the production wells on the other side are at the prime stage of production and require sufficient water injection to maintain the production, which leads to the discrepancy. To deal with the discrepancy, the most important point is not to treat the whole row of wells in the same way. On the contrary, the injection wells should be analyzed one by one and choice should be made of the most favorable injection allocation for most oil wells and high-yield oil wells.

d. Inter-row discrepancy of producing well rows

This discrepancy appears in the case of line-drive well pattern, i.e., three or more production well rows between two injection well rows. It has different characteristics at different development stages.

– The early stage of water injection response. Sometimes, under the condition of injection-production balance, water injection is fully response to the first row of production wells, much less response to the second row, and hardly any response to the third row, or even dissolved gas drive is used for the production. In this case, two injection wells with five rows of production wells in between should be considered unsuitable and three rows of production rows are enough.
– The early water breakthrough stage of the first row of production wells. By now, prominent effects have been achieved in the second row of production wells. At this moment, the discrepancy is not obvious on the surface, for both of the rows of production wells have strong productivity. However, the development of the second row of production wells has speeded up the water cut of the first row of production wells.
– The first row of production wells at the middle-and-high-water cut stage. At this time, reasonable water injection is needed for the first row of breakthrough production wells, so as to avoid water cut rising too fast. However, the second row of production wells is fully effective, or breakthrough has just happened to it, and it is necessary to give full play to its capacity with more water injection. This causes apparent contradiction, which can be moderated with the following methods:

    a. The fundamental way is not to use the line-drive well pattern, or two rows of injection wells with three rows of production wells in between, for this well pattern is not necessarily reasonable;
    b. At this stage, scattered injection wells should be added near the wells with a small spacing at the second row, which changes one-way displacement into two-way displacement. In this way, the wells at the second row as a whole production region will be divided into scattered zones, and the oil in the low water aquifer zone will be displaced into the high water aquifer well, where it can be extracted;
    c. Some of the high-water cut oil wells are chosen as converted-injector wells and the water injection line is shifted. As a result, occlusion zones may appear in some oil layers at the first row, which makes the increase of production wells necessary.

d. The production losses of the shut-in high-water cut wells at the first row are made up by the production wells at the second row. In this case, the number of production wells at the first row decreases and the utilization rate of oil wells also decreases, which may cause the oilfield production decline;
e. When the first row of oil wells reaches the high-water cut stage, the high-water aquifer zone can be blocked to strengthen the exploitation of other layers. In the blocked zones, production is mainly carried out at the row of wells in the middle. As a result, the inter-row contradiction at the row of wells in the middle is solved, but the interlayer contradiction there has intensified.

2. The influence of plane discrepancy on the development effect of oilfields

In many cases, plane heterogeneity is more intensive than intralayer or interlayer heterogeneity. Because the plane distribution of sand bodies is controlled by depositional conditions, for example, the braided channels of the alluvial fan and fluvial depositional sand bodies are distributed in the form of nets or strips on the plane with poor continuity and connectivity, and strong heterogeneity, the interjection-production pattern is difficult to control or the control is imperfect, and the plane discrepancy will intensify. To sum up, the imperfect interjection-production pattern will make the distribution of the remaining oil on the plane complicated.

The injected water moves forward quickly along the high-permeability zone on the plane. Plane penetration has a certain direction, that is, generally there is not much change in reservoir parameters along the horizontal distribution of sand bodies and the reservoir parameters change frequently in the vertical distribution of sand bodies. The injected water channeling can easily happen along the high-permeability zone, bypassing the low-permeability zone, so that the injected water cannot reach the low-permeability zone or belt, forming a retention area of remaining oil. Usually, remaining oil enrichment tends to form in well-developed thin sand layers, such as the sand bar flank in the delta front or interchannel shoals.

Long-time water injection development will make the plane heterogeneity of the waterflooding oilfields severe, thus intensifying the plane discrepancy, which is continuously aggravated in the case of big oil/water viscosity ratio. The following factors will cause low-efficiency oil displacement in the low-permeability zone and form enrichment of remaining oil in low-permeability formation: high oil–water viscosity ratio, uneven advancement of water drive front, small fluidity of crude oil, easy breakthrough of injected water into high-porosity and high-permeability zone, and quick tonguing of injected water in the direction with small resistance.

In reservoirs with serious plane heterogeneity, high recovery efficiency can be obtained by means of water injection in high-permeability zone and production in low-permeability zone. The equivalent permeability of the whole reservoir is significantly influenced by the relative distance between the plane heterogeneity reservoir and the water injection well. This is because the oil displacement efficiency of the core is related to its level of the equivalent permeability.

Therefore, as far as plane heterogeneity is concerned, by adopting the method of "water injection in high-permeability zone and production in low-permeability zone," the equivalent permeability of water injection in oil recovery is small and oil displacement efficiency is certainly small as well. The smaller the core permeability variation coefficient, then the more homogeneous the throats of the core assemblage, the less obvious the phenomenon of water breakthrough and the higher the recovery efficiency without water injection. Smaller water breakthrough is bound to make most of the throats flooded and the oil displacement efficiency of core increased. Reasonable infill well pattern is the fundamental method for solving the problem of reservoir interlayer and plane discrepancy.

1.4.3 Water-Flooding Features of Various Types of Rhythm

There are various types of sedimentary rhythm in sandstone reservoirs, and in the water-flooding process different types of rhythm vary in the rule of water–oil movement to some degree. The five models in Fig. 1.11 show that the bottoms are flooded first. The oil–water interface in the positive rhythm is concave-up, and that in the negative rhythm is concave-down. The layers in the compound rhythm are in the multi-phase flood-out pattern and the homogeneity is similar to that in the positive rhythm. This shows that the effect of water injection in the reverse rhythm is much better than that in the positive rhythm, and even superior to that in the homogeneous oil layer. The oil layers in the positive rhythm are flooded at the bottom. In the process, the injected water darts along the high-permeability zone at the bottom of the oil layer, which is accompanied by small water flooding thickness in the whole layer, early breakthrough, fast-rising water content, and unsatisfactory development effect. The compound rhythm oil layer belongs to the type of staging

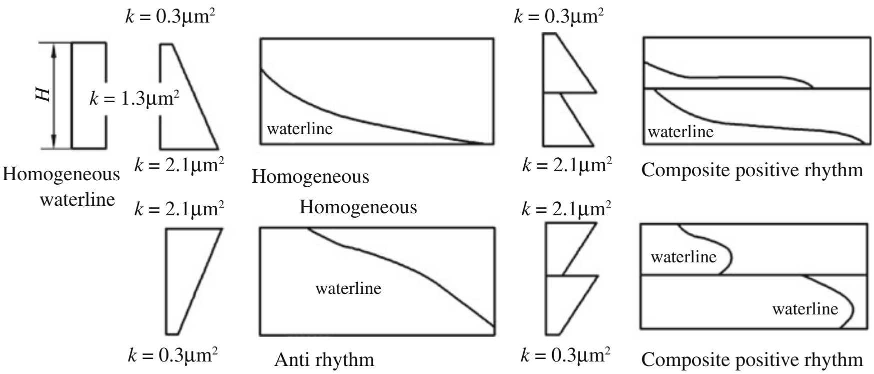


Fig. 1.11 The water line changes after breakthrough in various rhythm models

flood out, which is characterized by longitudinal multi-stage water flushing. In positive compound oil layers, the injected water darts along the high-permeability zone at the bottom, the washing thickness is bigger than that in positive rhythm oil layers, and the water-flooding performance is satisfactory; in inverted compound rhythm oil layers, washing thickness is big and the interlayer water-flooding performance is satisfactory.

1.4.4 Influence of Reservoir Microstructures on the Water-Flooding Performance

Generally speaking, microstructures include sedimentary structures, fine beddings, and oblique beddings in oil layers. Whether large or fine, they share the same fundamental principle in water-flooding performance. Many types of fine structure can be found in sedimentary rocks such as beddings, cross-beddings, and oblique beddings, which have significant impact on water-flooding performance. Ripples, mud cracks, burrows, and so on play an important role in the research of sedimentary rocks and sedimentary environments, but they have little influence on water-flooding performance.

1. The effect of fine beddings on water-flooding performance
a. The effect of various types of bedding on water-flooding performance

The purpose of studying beddings in oilfield development geology is to grasp the rule of bedding distribution and its effect on water-flooding performance. Different types of fine bedding have different effects on water-flooding performance.

– Horizontal beddings

Horizontal beddings are generally parallel to the layer's surface, with a stable far-extending distribution. If normal methods of perforation and water injection are adopted in mudstone oil layers with well-developed horizontal beddings, the effect of water-flooding is bound to decline. When the bedding planes open due to high pressure or where the horizontal beddings were originally open, water channeling or even minute stratum slipping may occur.

– Straight-line oblique beddings

Viewed from the profile, the common features of straight-line oblique beddings and horizontal beddings are that they are in rectilinear figure. The difference between them is that straight-line oblique beddings intersect the plane at a certain angle and horizontal beddings are generally parallel to it.

– Cross-beddings and arc oblique beddings

Cross-beddings and arc oblique beddings are the same rock mass that exists on different profiles. There is difference between the two types of beddings in terms of water-flooding performance, but it is not remarkable. Cross-beddings are better in that their water-free recovery is higher.

The water-flooding performances of different types of beddings are compared as follows in Table 1.5.

b. The effect of oil displacement directions on the water-flooding performance

In terms of the effect of the oil displacement directions on the water-flooding performance, the bedding types can be divided into two parts: one consists of horizontal beddings and straight-line oblique beddings, and the other consists of arc oblique beddings and cross-beddings. Cross-beddings and arc oblique beddings are through cross-beddings on different profiles. As is remarkably shown in Table 1.5, the effects of oil displacement differ in different directions.

To a great degree, water-flooding performance depends on whether its direction is parallel or perpendicular to the direction of straight-line oblique beddings. When it comes to slightly oil–wet rock core: if the main stream direction from the water injection well to the producing well is parallel to the fine bedding direction, the water will advance along with the high-permeability strip, which causes small flooded area and low recovery; if the direction is vertical to the fine bedding direction, the result is the opposite.

As for the weakly water–wet oil layer, the general tendency basically remains unchanged and the discrepancy is small. However, there is plenty of work to be done seriously before the conclusion is made, for the opposite result may appear as long as reasonable injection and production rate is adopted.

Therefore, the water-flooding direction should be seriously chosen for the reservoir with oblique beddings and fine beddings which is located in the fluvial delta.

2. The impact of rock-forming minerals directional alignment on the development effect in the oilfield

Rock-forming minerals' directional alignment is a micro-problem that causes oil layer plane heterogeneity. The deposition of the grains which make up the sandstone is directional. The direction is influenced by not only the strength of the water flow but also the factors such as the locative terrain, waves, and underflow.

Table 1.5 Oil displacement efficiency of different types of bedding

The bedding types	Permeability	Water-free recovery	Ultimate recovery	Water injection multiples
Straight-line oblique beddings	0.723	2.82	21.3	1.07
Fine arc oblique beddings	0.5401	21.6	42.2	1.56
Cross-beddings	0.2213	30.6	42.7	0.688

The impact of sandstone particles' directional alignment on the water-flooding performance can be analyzed from two points:

a. Whether the water-flooding direction is parallel to the paleocurrent direction

When the water-flooding direction is parallel to the paleocurrent direction, the permeability is high because the pore channels formed by particles are direct and the pore sizes vary only a little. The water will displace the oil along the relatively direct channels so that the water-flooding cannot reach the low-permeability pores in the opposite direction, which causes bad water-flooding performance.

When the water-flooding direction is perpendicular to the paleocurrent direction, the permeability is low because there are many pore curves and bends formed by particles, the variation of pore size is large, and in the small pores vertical to the direction of the water flow there are fine particle sediments. Therefore, the water displaces the oil both in large and small pores and the performance is satisfactory.

The two methods mentioned above are compared, the former has a higher oil production and bad water-flooding performance, and the latter is the opposite.

b. Whether the water-flooding direction is fair current or countercurrent

Under the condition of directional alignment of rock grains, the big ends of the grains face the direction of the water flow, or the directional alignment of rock grains faces the direction whose flow resistance is the smallest. The direction of oil displacement is the same as that of the water flow through the pores formed by these grains, i.e., the water flows from the big ends to the small ends with small flow resistance. If the direction of oil displacement is opposite to that of the water flow, i.e., from the small ends to the big ends of the grains, the flow resistance is big.

From the analysis above, we can draw a conclusion that the impact of the fine bedding structure on the water-flooding performance lies in the direction and number of pores. In general, the water-flooding direction with high recovery is the direction of low production capacity and vice versa.

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.

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DOI 10.1007/978-3-662-53287-4_2

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.

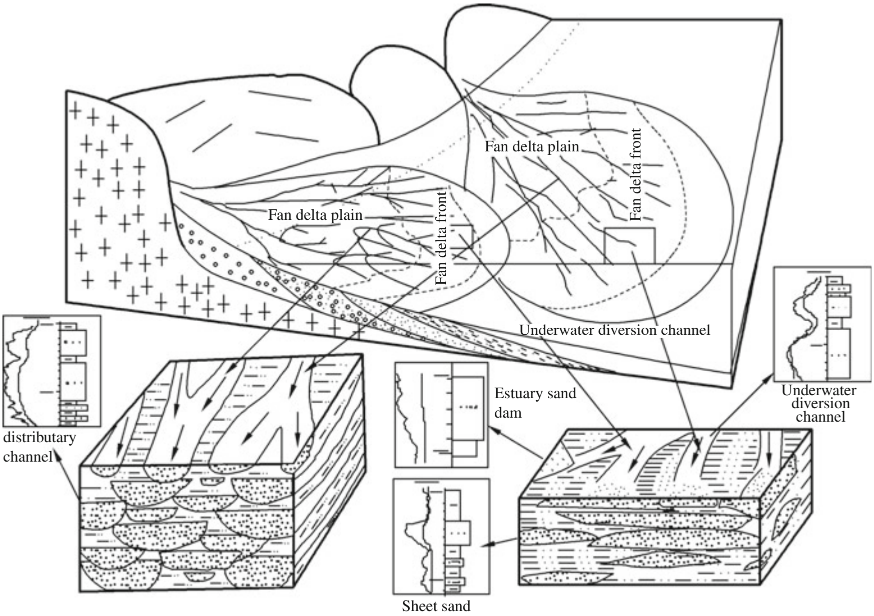


Fig. 2.1 Fan delta front and pro-fan delta depositional model

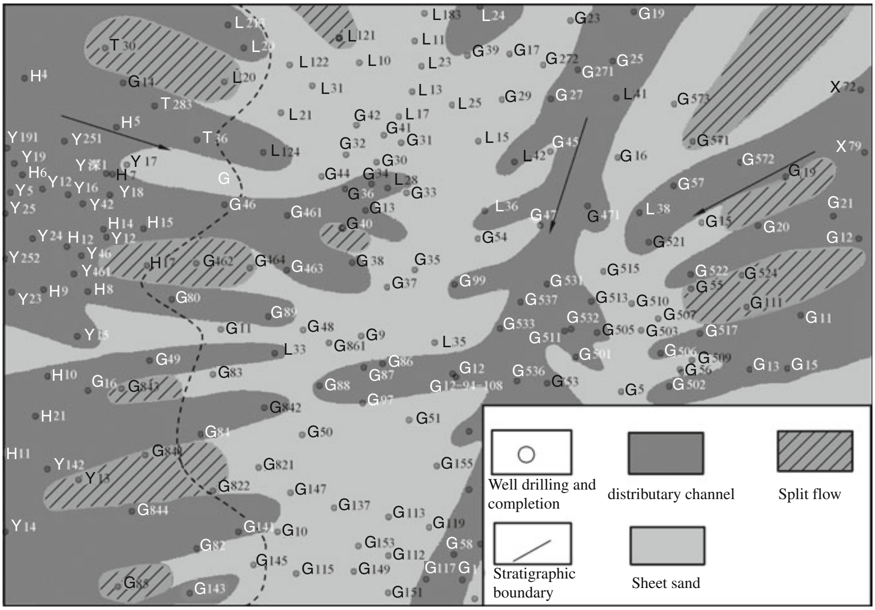


Fig. 2.2 A schematic diagram of reservoir provenance and deposition direction

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 Kmax 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

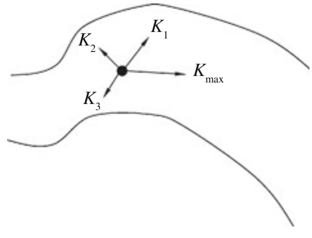
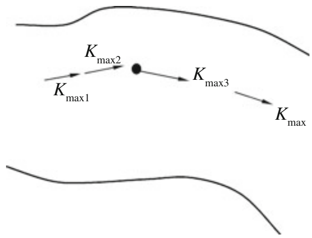


Fig. 2.3 Schematic of permeability at any point

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.

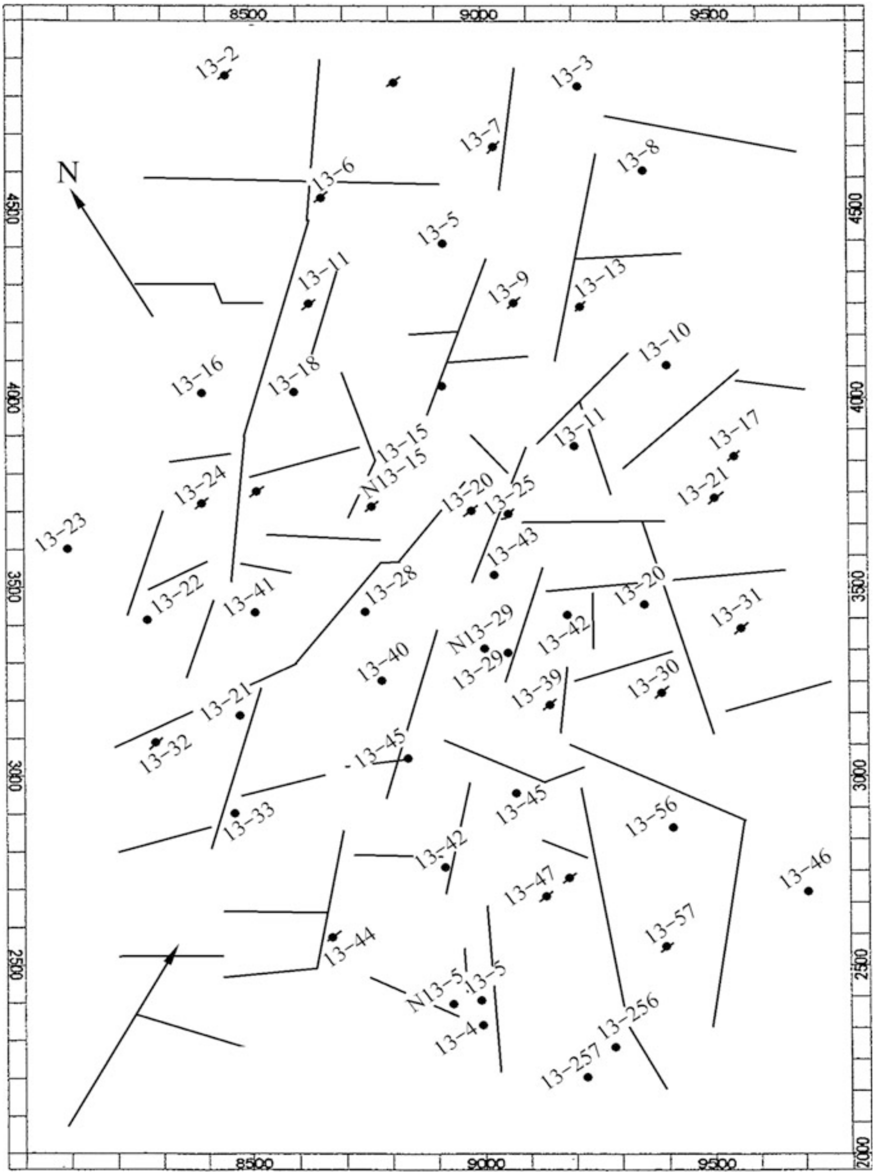


Fig. 2.5 Schematic diagram of the distribution of cracks in Wen Block 13 of Zhongyuan Oilfield

The fault strike refers to the direction of crack extension when rock mass rupture occurs. As shown in Fig. 2.6, if there are faults in an oil-and-gas reservoir, it will be divided into different blocks, whose continuity and permeability will be affected. Due to the complexity and diversity of faults, they can be divided into different types, such as simple normal fault, reverse fault, sealing fault, and non-sealing fault.

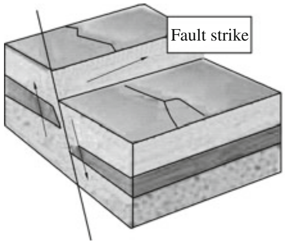


Fig. 2.6 Fault strike

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

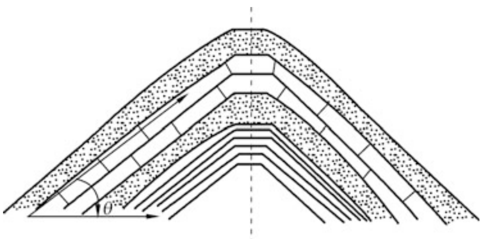


Fig. 2.7 Structural dip

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.

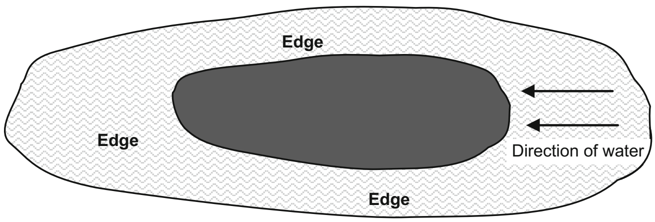


Fig. 2.8 Oriented edge water invasion

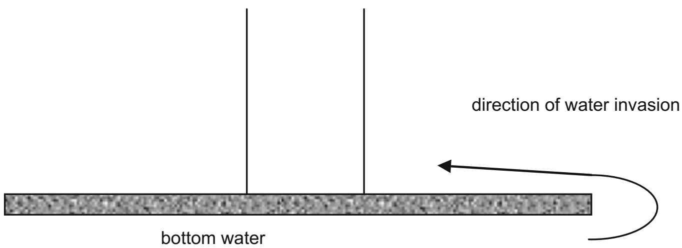


Fig. 2.9 Bottom water invasion bypasses the interlayer

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

$$\Gamma(x) = \int_{0}^{\infty} e^{-t} t^{x-1} dt \tag{2.1}$$

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 coincidenced 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:

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

The corresponding distribution function is:

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

Calculation steps are as follows:

a. 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.
b. 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.
c. 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.

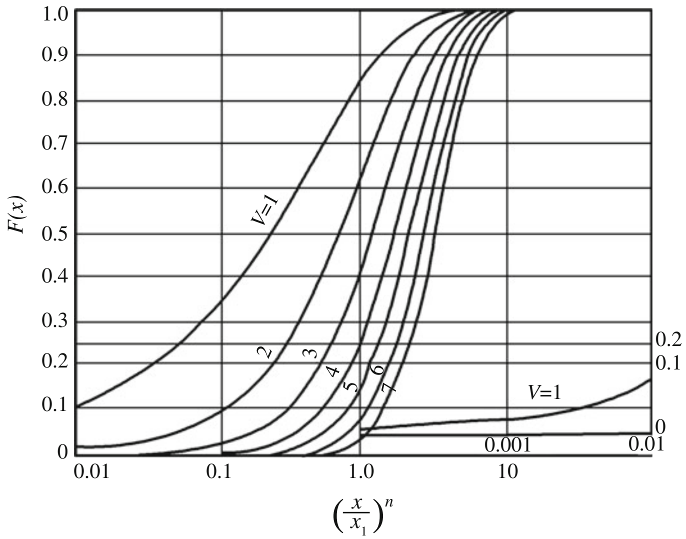


Fig. 2.10 The relationship of theoretical distribution and $(x/x_1)^n$ relationship

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:

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

Variance σ^2:

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

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} μm^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} μm^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:

$$V = \frac{\sigma}{\mu} \tag{2.6}$$

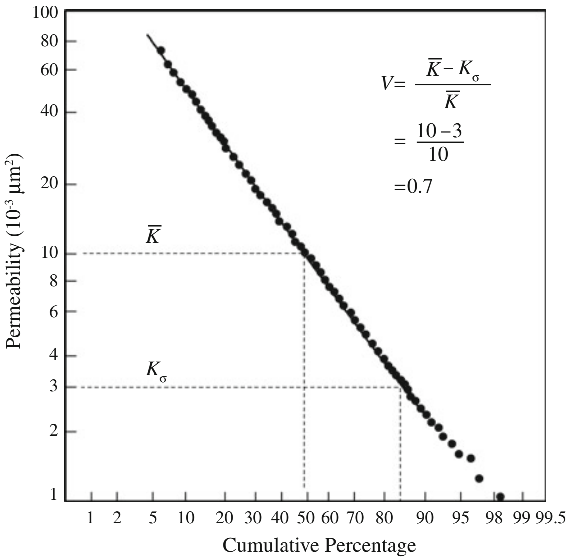


Fig. 2.11 Lognormal distribution

For lognormal distribution, the variation coefficient is:

$$V = \frac{\lg K_\sigma - \lg \bar{K}}{\lg \bar{K}} \tag{2.7}$$

In this example, K_σ = 3 (the corresponding accumulative percentage is permeability value 84.1 %, 10^{-3}μm^2),

$\bar{K}$ = 0, 10^{-3}μm^2 so V = 0.7 (the mean of permeability distribution).

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

$$V = \frac{K_\sigma - \bar{K}}{\bar{K}} \tag{2.8}$$

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 0.01×10^{-3} μm^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.

Orientational 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

$$K = \begin{bmatrix} K_x & 0 & 0 \\ 0 & K_y & 0 \\ 0 & 0 & K_z \end{bmatrix} \tag{2.9}$$

where K_X, K_y, and K_z are main permeability values along the direction x, y, and z, 10^{-3} μm^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:

$$K = \begin{bmatrix} K_x & 0 \\ 0 & K_y \end{bmatrix} \tag{2.10}$$

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} μm^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:

$$Q_n = Q_x + Q_y \tag{2.11}$$

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:

$$v_n = \frac{K_n}{\mu} \nabla P_n \tag{2.12}$$

So the flow rate that goes through section A is:

$$Q_n = Av_n = -A\frac{K_n}{\mu} \nabla P_n \tag{2.13}$$

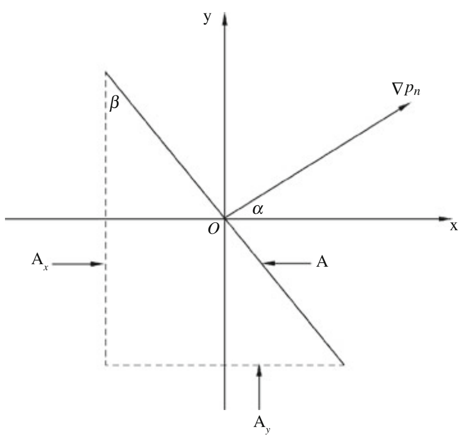


Fig. 2.12 Deduction of calculation model of permeability

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

$$A_x = A\cos\beta = A\cos\alpha \tag{2.14}$$

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

$$A_y = A\sin\beta = A\sin\alpha \tag{2.15}$$

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

$$\nabla P_{nx} = \nabla P_n \cos\alpha \tag{2.16}$$

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

$$v_n = \frac{-K_x}{\mu}\nabla P_{nx} \tag{2.17}$$

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

$$Q_x = v_x A_x \tag{2.18}$$

So,

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

The same can be obtained:

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

Then,

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

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

Then,

$$K_n = K_x \cos^2 \alpha + K_y \sin^2 \alpha \tag{2.22}$$

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,

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

The calculation formula for the experimental variation function is:

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

In the equation,

x_i	is the coordinates of the ith 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, …, 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):

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

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 $\boldsymbol{\alpha}$ 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 $\boldsymbol{\alpha}$ 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:

$$\frac{\partial^2 p}{\partial^2 r} + \frac{1}{r}\frac{\partial p}{\partial r} = \frac{\phi \mu C_t \partial p}{3.6\bar{k}\partial t} \tag{2.26}$$

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

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

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:

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

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

$$P_D = \frac{\bar{k}h}{1.842 \times 10^{-3} qB_o\mu}\Delta p \tag{2.29}$$

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

$$r_D = \frac{r}{r_w} \tag{2.31}$$

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:

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

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

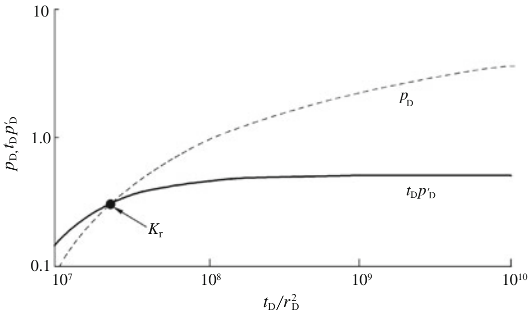


Fig. 2.13 TDS method used to obtain the figure of directional permeability k_r

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 $\left(t_D/r_D^2\right)_{\text{node}}$, and the directional permeability k_n can be easily obtained, that is,

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

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:

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

According to Fig. 2.14,

$$\theta_i = \beta_i - \alpha \tag{2.35}$$

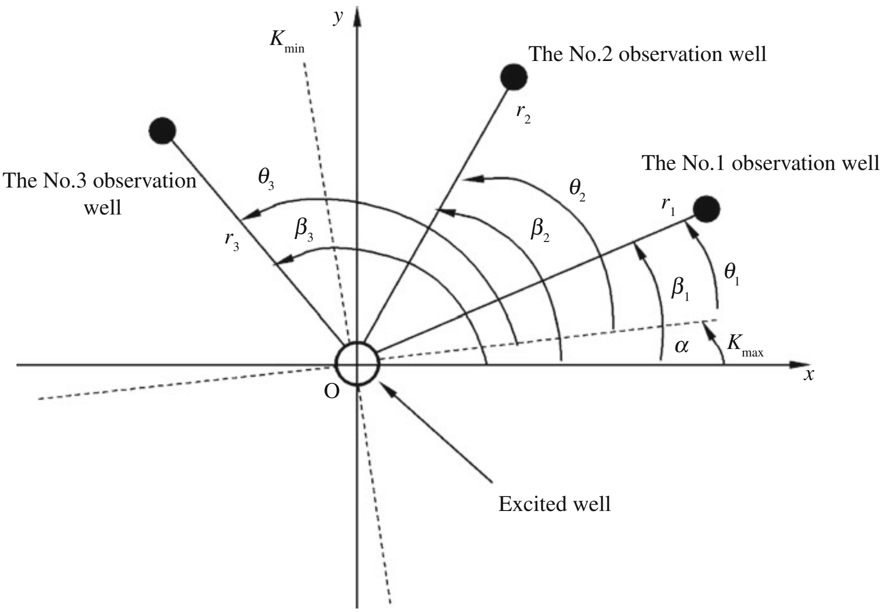


Fig. 2.14 Distribution of interference test wells

then,

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

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):

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

The value a, $k_{\max}$, 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:

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

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

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

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

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

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:

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

where

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

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

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

then,

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

Remove c and we can get

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

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:

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

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.

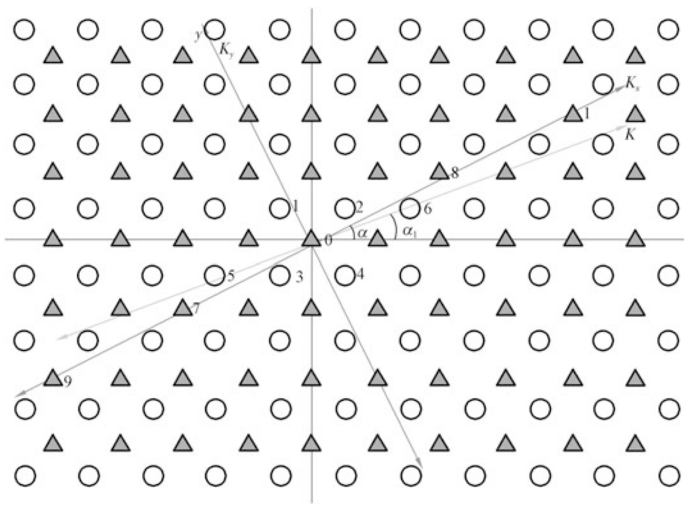


Fig. 2.15 Square five-spot well system of an anisotropic reservoir

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:

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

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 $\left(K_x/K_y\right)^{1/4}$ times in x-direction, while in y-direction it extends $\left(K_x/K_y\right)^{1/4}$ 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

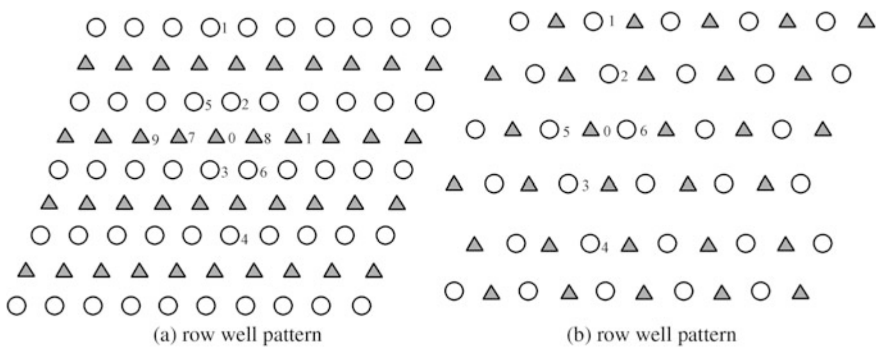


Fig. 2.16 Deformed well pattern with different angle equivalents

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.

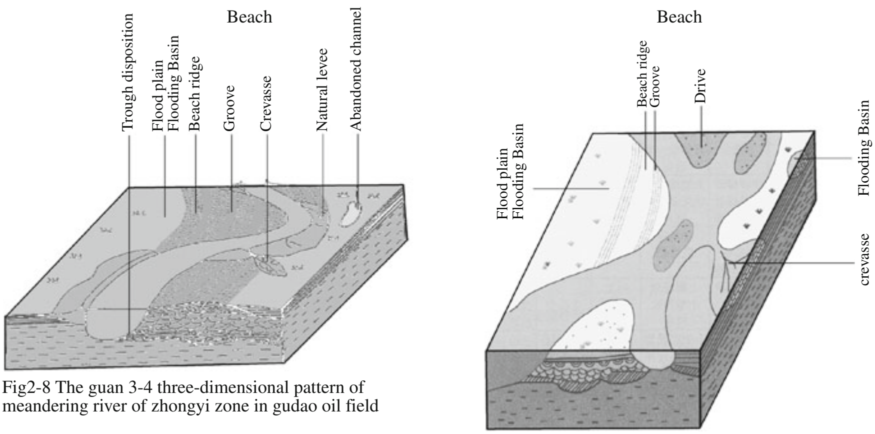
For the arbitrary angle α, the well pattern in Fig. 2.15 is related to an equivalent deformed well pattern. In theory, if $\left(K_x/K_y\right)^{1/4}$ value is big enough, the original well pattern will become the well pattern shown in Fig. 2.16a when the main direction K_x is parallel to the connecting 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



(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.

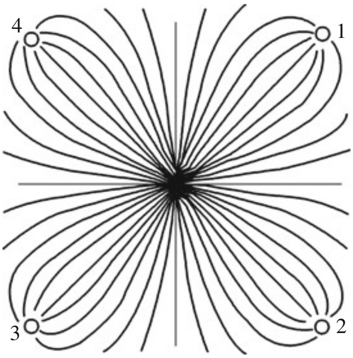


Fig. 2.18 Streamlines and front curves of five-point system in homogeneous reservoir. *1*, *2*, *3*, *4* is production well

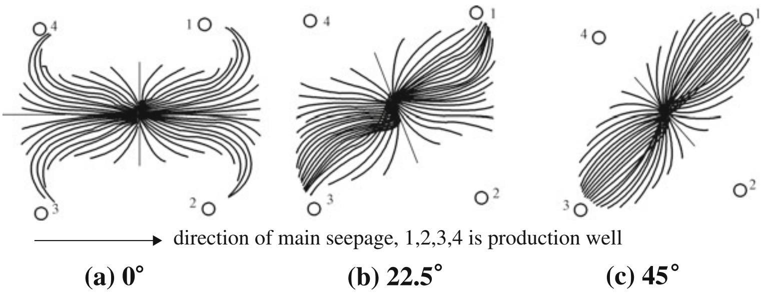


Fig. 2.19 Streamlines and front curves when the angles between the injection well array in five-spot system and the maximum principal permeability are different

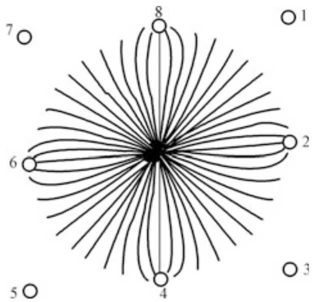


Fig. 2.20 Streamlines and front curves of nine-point spot system in a homogeneous reservoir. *1*, *2*, *3*, *4*, *5*, *6*, *7*, *8* is production well

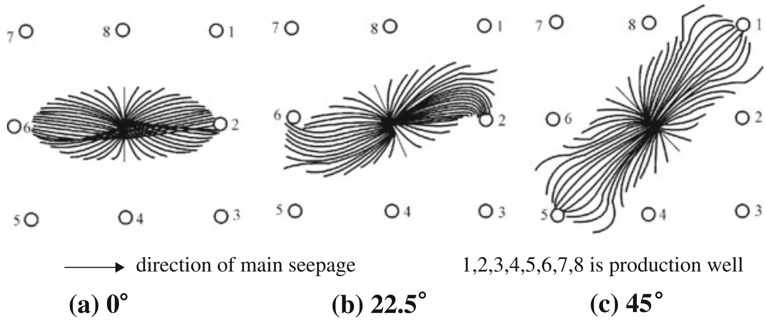


Fig. 2.21 Streamlines and front curves when the angles between the injection well in nine-spot system and the maximum principal permeability are different

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 cm^3/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} μm^2)	Driving speed (cm^3/h)	Irreducible water saturation (%)	Fracture azimuth (°)	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.

Chapter 3
Injection-Production Well Pattern Optimal Control Theory

Oil and gas field development is a complicated system engineering, one of whose systems is the injection-production well pattern system. The well pattern is an old problem and a challenging topic. It is directly related to whether the long-term stable production and good economic benefits for oil and gas companies can be achieved or not.

3.1 Waterflooding Characteristics in Sandstone Reservoirs

3.1.1 Overview of the Well Pattern Research

The research target of this book is to establish a theoretical system of injection-production well pattern optimal control, which provides a scientific method and basis for the arrangement and adjustment of the well pattern in waterflooding oilfields.

The research of the reasonable well pattern in the oil and gas field development has received significant attention in recent history. In the 1940s, Muskat made a study on theory of flow mechanism of simple well pattern. Several authors in literature have advanced the discussion and have established important theories about the relationship between reservoir sweep and injection models under the condition of unit reservoir heterogeneity and unit mobility ratio. Subsequently, in the 1950s, research in the area was further developed during water flooding process under the condition of random mobility ratios and the rules governing the reservoir area sweep variation was established. However, in the late 1950s, the method of “sparse well pattern for large pressure decline” was proposed by other researchers, but their applications failed in practice. In the late 1960s, V.N. Shelkachev (Russian) developed empirical relationship for the determination of final oil

D. Liu and J. Sun, *The Control Theory and Application for Well Pattern Optimization of Heterogeneous Sandstone Reservoirs*, Springer Geology,
DOI 10.1007/978-3-662-53287-4_3

recovery and well spacing density. Similarly, Daqing Oilfield suggested that, “well placing is affected by the size of reservoir sand,” in that the relationship of water drive control extent and well pattern is determined by oil sand map. In the early 1980s, TONG Xianzhang proposed a method to optimize well pattern leading to the realization of maximum production. In the early 1990s, QI Yufeng presented the well pattern system theory. Moreover, LANG Zhaoxin and others initiated the research on the production of the horizontal well pattern. After 2003, LIU Dehua proposed the concept of the vector well pattern and corresponding well spacing methodologies. In 2005, LIU Yuetian from China University of Petroleum studied the water injection methods and well arrangement theories of anisotropic reservoir.

Moreover, with the continuous development of oilfield development theory, cognition of the well pattern is also in progress. Because well pattern is very important in the production of oil and gas fields, and the selection, deployment, and adjustment of well pattern are the determination of the production scale, the life of production, and the economic benefits of oil and gas field. Onshore oil and gas fields are mostly heterogeneous reservoirs. Well pattern optimization is particularly important. Therefore, the establishment of well pattern optimization control theory has an important guiding role in improving the oilfield development.

With the development of oil and gas fields, and the continuous change of the drive modes, the development system becomes increasingly complex. This brings to bear much demand for further and detail research on well pattern or well pattern efficiency. From system perspective, well pattern system which consists of individual well is a subsystem of oil and gas field development system. Consequently, in order to better handle the well pattern challenges, it is ideal to resolve the well pattern holistically through the combined optimization of the individual wells. This involves the combined evaluation of all the major inputs such as drainage radius of single well, multi-well interference and injection-production balance, and the position and function of well pattern in the system of oil and gas field development, thus looking at the problem as a socially complex giant system. For a reasonable well pattern optimization, the approach should involve the principle for minimum number of wells, largest controlled drainage area, higher hydrocarbon recovery rate, satisfactory or acceptable oil and gas production rate, flexibility of the well pattern, lowest managerial cost of ground facilities, and so forth.

With the growth of well pattern research methods, the research direction is establishing a complete mathematical model about well spacing density based on various factors and software implementation. Its choice, deployment, and adjustment should start from the perspective of system and utilize advanced optimization method, with the influence of various factors taken into consideration. So far, the study of the horizontal well pattern forms just focuses on the regular well pattern, rarely on the irregular well pattern. If we can strengthen the research of irregular well pattern, it will be good for combining the production experience and theory. There are few theoretical researches for the non-horizontal directional well, especially for the well with a circular-arc or parabola shape and so on. However, this kind of directional well is useful when the oil sand bodies extend in a curved strip on the plane. Therefore, it is necessary to carry out theoretical research on this type of directional wells. In summary, the complexity of reservoir has determined the difficulty of the well pattern research, but it can be certain that more and more new effective methods will appear constantly.

3.1.2 Types and Characteristics of the Areal Well Pattern Deployment

In sandstone reservoir development, the areal well pattern is very common for water flooding. It is defined as deploying injection wells and production wells at a certain geometric shape with uniform density in the entire development block. The essence of this method of water injection is dividing the reservoir into many smaller units, in which one injection well controls some production wells, and each production well is influenced by many injection wells in several directions.

Usually, the well pattern arrangement can be described by different points of the injection water system. This method refers to the injection-production unit formed by connecting injection wells around the oil well. The total well number of this unit is represented by the *n*-spot system. On the contrary, if the injection well is taken as the center and an injection-production unit formed through connecting several production wells around the injection well with the well number as *n*, it is called the reverse *n*-spot injection system. Because the production well is influenced by different waterflood directions in this injection-production system with sufficient influence of injection water, the production wells have a high oil production rate. Naturally, this flooding mode is adopted in most sandstone reservoirs.

According to the location of the production well and water well, and the shape of the well pattern, the areal well pattern can be divided into the four-spot pattern, five-spot pattern, seven-spot pattern, nine-spot pattern, inverted seven-spot pattern, inverted nine-spot pattern, linear injection, and staggered water injection, as shown in Figs. 3.1, 3.2, 3.3, 3.4, 3.5, and 3.6.

Characteristics of different areal well patterns are shown in Table 3.1.

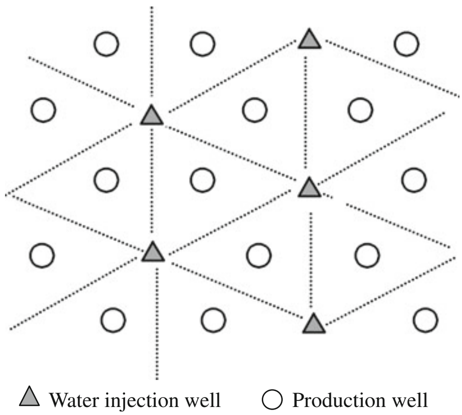


Fig. 3.1 Schematic diagram of the four-spot well pattern

Fig. 3.2 Schematic diagram of the five-spot well pattern

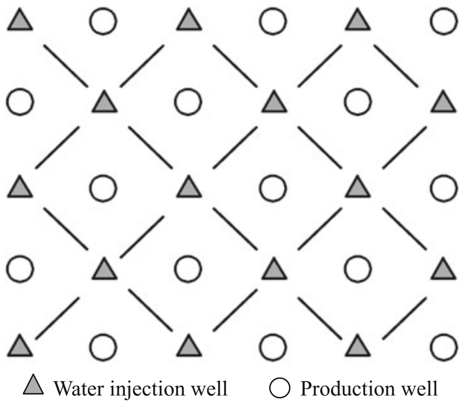


Fig. 3.3 Schematic diagram of the seven-spot well pattern

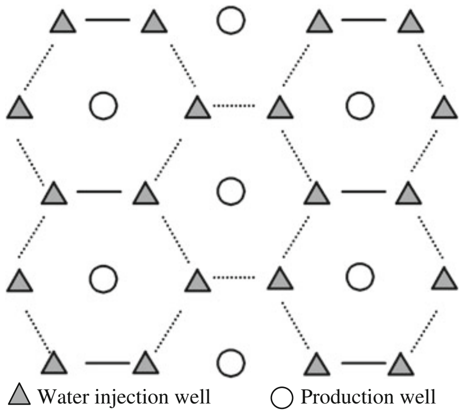
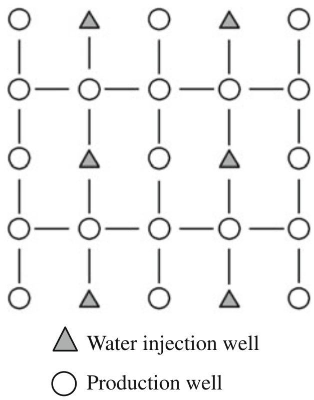


Fig. 3.4 Schematic diagram of the inverted nine-spot well pattern



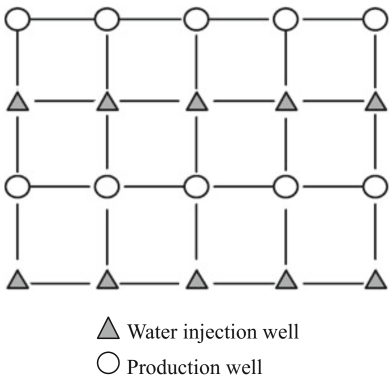


Fig. 3.5 Schematic diagram of the direct-acting-type well pattern

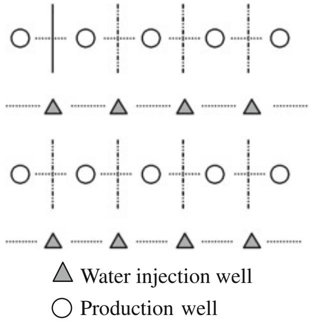


Fig. 3.6 Schematic diagram of the stagger-type rowed well pattern

Table 3.1 Basic characteristics of the areal well pattern

Well pattern	The ratio of injector-to-production well	Requirement for well pattern
Four-spot	1:2	Equilateral triangle
Skewed four-spot	1:2	Square
Five-spot	1:1	Square
Seven-spot	2:1	Equilateral triangle
Inverted seven-spot	1:2	Equilateral triangle
Nine-spot	3:1	Square
Inverted nine-spot	1:3	Square
Linear drive opposite row	1:1	Square
Staggered drive	1:1	Injection-production well stagger

a. The four-spot well pattern

With this water injection method, injection wells are located at the vertex of the regular triangle and the oil well is in the center of the triangle, or several oil wells form a regular hexagon and the injection well is located at the center, as shown in Fig. 3.1. Each oil well is influenced by three injection wells, and each injector controls six oil wells, so the injector-producer ratio is 1:2. The four-spot injection method can also be taken as a special case of line waterflooding; namely, two rows of production wells are located between two rows of injection wells. The well array spacing is the distance between the production well line and injection well line. The well spacing is the distance between two wells on the same well line, and the ratio of the well array spacing to the well spacing is $d/a = 1{:}2\sqrt{3} = 0.289$.

b. The five-spot well pattern

This five-spot well pattern is a square pattern with injection wells connected, and the production well is located at the center of each water injection unit. Each production well is influenced by four injection wells, and each injection well will be influenced by four production wells, as shown in Fig. 3.2. The number of injection wells is equal to production wells in the five-spot well pattern. Due to the large proportion of injection wells, this well pattern is an intensive injection and production system. It may also be regarded as a particular form of line injection which can be treated as a stagger arrangement of the production well array and water injection array, and the ratio of the well array spacing to the well spacing is $d/a = 0.5$, in which d is array spacing and a is well spacing.

With the growth of the water injection time, the water gradually advances to the production wells, but this advance is uneven in different directions. With the effect of drawdown pressure, the injection water directly arriving in the nearest production well reaches it first, forming the fingering phenomenon.

c. The seven-spot well pattern

If the positions of the production wells and injection wells are exchanged or half of the production wells are converted into injection wells in the four-spot well pattern, it can turn into the seven-spot well pattern, as shown in Fig. 3.3. The injector-producer ratio is 2:1 for this kind of well pattern, and the number of the oil wells influenced by one injection well decreases from six to three. Therefore, this is a development pattern with high strength injection, requiring more wells. The ratio of the well array spacing and well spacing is $d/a = 1{:}2\sqrt{3} = 0.289$.

d. The inverted nine-spot well pattern

The injection-production unit is a square pattern which contains one injection well and eight production wells. The injection well is at the center of the injection unit, the four production wells are located in the corners of the square unit (called the corner well), and another four wells are on the touchlines (called the edge well), as shown in Fig. 3.4. The injector-producer ratio is 1:3 for this kind of well pattern, which is utilized very often in practice. The ratio of the well array spacing and well spacing is d/a = 1/1.

e. The direct-facing-type rowed well pattern

The injection wells and production wells are arranged in a straight line with the same well spacing. Each basic unit is a parallelogram. The water well is located at the center, and the production wells are located in the four corners, as shown in Fig. 3.5.

f. The stagger-type rowed well pattern.

Each basic unit is a rectangle. The water injection well is located at the center, and the injection well spacing is equal to production well spacing. Each injection well will be influenced by four production wells, and each production well is also influenced by four injection wells, as shown in Fig. 3.6.

3.1.3 *Comparison of Different Well Patterns*

A comparison is made of the basic features of the areal well pattern in the above text. Next, an analysis will be made of the three kinds of well pattern (the four-spot pattern, five-spot well pattern, and nine-spot well pattern) from the following factors: injection-production in density, water injection sweep efficiency, water flooding control degree, oil production rate, flexibility adjustment of the well pattern system, and so on.

1. The injector-to-producer well number ratio for different well patterns

Injection-production intensity and the injector-producer ratio for different well patterns are showed in Table 3.2.

If the arithmetic product of the injection-production-well ratio and production well spacing density represents the injection-production intensity, obviously, the well pattern capacity of water injection and oil production is increasing as the value of the arithmetic product rises. Injection-production intensity is an important index of well pattern system. From Table 3.2, the five-spot well pattern has the largest injection-production intensity.

2. Waterflood sweep coefficient of different well pattern systems

The plane geometrical relationship of well patterns has a great influence on water sweep efficiency. From the plane, water injection and oil production are conducted at the well point. In a uniform well pattern, the connecting line between the injection wells and production wells is the shortest streamline between two wells. Due to the largest pressure gradient along the line, the injection water will be pushed along the line to the production well on the plane before the injection water gradually spreads to the other parts of the reservoir along the other streamlines.

Table 3.2 Injection-production intensity of different well patterns

Injection water system	Injector to producer ratio (M)	Single oil well control area (km^2/well)	Average control area of oil and water wells (km^2/well)	Oil well spacing density (wells/km^2)	Oil and water well density (wells/km^2)	Injection-production intensity $M\eta_o$
Four-spot	1:2	$\frac{3\sqrt{3}}{4} \times 10^{-6}a^2$	$\frac{\sqrt{3}}{2} \times 10^{-6}a^2$	$\frac{4}{3} \times \frac{10^6}{\sqrt{3}a^2}$	$\frac{2\times10^6}{\sqrt{3}a^2}$	$\frac{0.385\times10^6}{a^2}$
Five-spot	1:1	$2 \times 10^{-6}a^2$	$1 \times 10^{-6}a^2$	$\frac{1\times10^6}{2a^2}$	$\frac{1\times10^6}{a^2}$	$\frac{0.5\times10^6}{a^2}$
Inverted nine-spot	1:3	$\frac{4}{3} \times 10^{-6}a^2$	$1 \times 10^{-6}a^2$	$\frac{3}{4a^2} \times 10^6$	$\frac{1\times10^6}{a^2}$	$\frac{0.25\times10^6}{a^2}$

Annotation: α represents the distance between the production well and injection well; for the inverted nine-spot well pattern, it represents the distance between the edge well and the injection well; η_o represents oil well spacing density

Therefore, the area swept by injection water between the injection wells and production wells is called sweep area after water breakthrough. For homogeneous reservoirs, the water injection sweep efficiency of different well pattern systems can be represented by the following formula:

$$\text{Five-spot well pattern } K_B = 0.718E \tag{3.1}$$

$$\text{Four-spot well pattern } K_B = 0.743E \tag{3.2}$$

$$\text{Inverted nine-spot well pattern } K_B = 0.525E \tag{3.3}$$

$$E = [(1 + \mu_R)/(2\mu_R)]^{0.5} \tag{3.4}$$

$$\mu_R = \frac{\left[K_{\mathrm{w}}(\overline{S}) + K_{\mathrm{o}}(\overline{S})\right]/\mu_w}{[K_{\mathrm{o}}(S_{\mathrm{wr}})]/\mu_{\mathrm{o}}} \tag{3.5}$$

where

μ_R	is water–oil mobility ratio;
$\overline{S}$	is frontal average water saturation;
K_{o}, K_{w}	are oil phase and water phase permeability, respectively, 10^{-3} μm^2; and
S_{wr}	is irreducible water saturation.

It can be concluded that waterflood sweep efficiency of the well pattern system mainly depends on the water–oil mobility ratio. The greater the water–oil mobility ratio, the lower the water sweep area. At a certain value of water–oil mobility ratio, the waterflood sweep coefficient of the five-spot well pattern is similar to that of the four-spot well pattern, and the value of the inverted nine-spot well pattern is the lowest. This is mainly because the edge well spacing and corner well spacing differ by $\sqrt{2}$ times. When the water breakthrough occurs in the edge wells, the waterfront is still far away from the corner well.

For the oil layers with bad planar discontinuity, the water sweep efficiency is significantly influenced by well spacing. The smaller the well spacing, the bigger the waterflood sweep efficiency. Of the three kinds of common areal well pattern, the five-spot well pattern system is the best.

3. Waterflooding control degree in different well patterns

The control degree of water flooding has a direct effect on the water drive recovery. Through statistical analysis of different well pattern systems, the formula of waterflooding is created:

$$\lambda = 1 - \sqrt{\frac{1}{M}}\exp\left(-KC\frac{10^6}{\alpha.a^2}\right) \tag{3.6}$$

where

M is injector-producer ratio;
a is well spacing, m;
α a is conversion ratio between the single well control area and well spacing square (α = 0.866 for the four-spot well pattern, a = 1 for the five-spot well pattern, and nine-spot well pattern);
K is constant;
C is sand area, m^2.

The formula shows that the control degree of waterflooding depends on the water injection system, well spacing, and distribution of sand bodies. The smaller the well spacing and the larger the area of the sand body, the greater the degree of waterflooding control of the well pattern (well spacing is also restricted by the economic indicator). As a result, when the well spacing and sand body distribution area are constant, the five-spot well pattern system has the highest level of waterflooding control degree.

4. Oil production rate of different well patterns

In a well pattern unit, the following formula is deduced under the condition that the injection and production are in balance.

$$V_o = \frac{TI_B \eta_o M}{[B/r + f/(1 - f)]A} \tag{3.7}$$

in which,

V_o is oil production rate, decimals;
I_B is water injection intensity, $m^3/(d\ m)$;
η_o is oil well density, $wells/km^2$;
M is injector-producer ratio;
A is single reserve factor, $10^4/(km^2\ m)$;
B/r is oil volumetric factor;
f is water cut of the oil well, decimals; and
T is the production well's production days per year, d.

The formula shows that the injection-production intensity $\eta_o M$ of the well pattern system is an important factor to oil production rate in a well pattern unit. When the water cut and water injection intensity are the same, the five-spot well pattern has the highest oil production rate, which is followed by the four-spot well pattern system, with the oil production rate of the inverted nine-spot well pattern being the lowest. Therefore, for reservoirs of low permeability and severe heterogeneity, the five-spot well pattern system can get the highest oil production rate.

Applying China's development data of 15 low-permeability reservoirs, we can obtain the relational expression of oil production rate by multivariate analysis.

$$V_o = 2.2755 - 1.476 \times 10^{-2} \cdot N - 9.497 \times 10^{-2} \frac{1}{M} - 4.73 \times 10^{-7} \cdot \eta_o \quad (3.8)$$

in which,

V_o is five-year average oil production rate before development, decimals;
N is the single well-controlled reserves, 10^4 t/well;
M is injector-producer ratio;
η_o is oil well density, wells/km^2;
R is multiple correlation coefficient, $R = 0.87$;
S is residual standard deviation, $S = 0.19$.

The formula shows that oil production rate will improve with the increase of well spacing density and injector-producer ratio.

5. Flexibility of adjustment of the same well pattern system

    a. The inverted nine-spot well pattern system: When injection water advances quickly toward the corner well in the inverted nine-spot well pattern, this shows that directional permeability or fractures are distributed along the direction of the corner well. The inverted nine-spot well pattern should be converted into the five-spot well pattern to focus injection on the corner well. When injection water advances quickly toward the edge well, the inverted nine-spot well pattern should be converted into the linear injection water system to focus on the edge well. This transformation can expand the waterflooding sweep efficiency and improve the effect of water injection development. For fractured reservoirs, the inverted nine-spot well pattern, which is flexible for adjustment, should be used at the beginning of the injection when the fractures are not clear.
    b. The five-spot well pattern system: If the oil wells are water-flooded quickly in the five-spot well pattern, this shows that directional permeability or fractures are distributed between the oil well and water well. Then, the injection wells in the four corners must be shut and the oil well at the center must be converted into an injection well, which can work with the four adjacent production wells to form a new five-spot well pattern. The waterflooding direction of the new well pattern intersects the fracture to form an included angle of 45°. In essence, this transition is to convert a small five-spot pattern into a large five-spot pattern system. If the original well spacing is a, then the new well pattern spacing becomes $\sqrt{2}a$. This transformation can greatly increase the waterflooding sweep efficiency. However, the water flooding control degree may be reduced due to the increase of well spacing for the reservoir with planar discontinuous distribution.

c. The four-spot well pattern system: There are three waterflooding directions for a production well at the same time. No matter which direction is the principal permeability or fractures, it is hard to make a flexible adjustment in accordance with the dynamic water injection because oil and water wells are distributed in the same direction. This is the main drawback of the four-spot well pattern system.

3.1.4 The Choice of the Areal Well Pattern

1. The applicable conditions for the areal well pattern;

   a. The area of an oilfield is large with incomplete structures and complex fault distribution;
   b. Reservoir distribution is irregular, with bad extensibility, and most of them are distributed in the form of lens. If cutting water injection is adopted, it is impossible to control most of the oil layers;
   c. Poor reservoir permeability and low flow coefficient. If cutting water injection is adopted, there will be a small effective impact area and a low oil production speed due to the large flow resistance;
   d. It can be utilized at the late stage of production for enhancing recovery;
   e. It is especially suitable for high-speed production oilfield.
   From the practice of Daqing Oilfield, cutting water injection is suitable for the reservoir with stable distribution and regular geometry of oil sand bodies. On the contrary, the areal well pattern can be suitable for the reservoir with unstable distribution and irregular geometry of oil sand bodies. Therefore, the areal well pattern has a wide adaptability. To sum up, cutting water injection has good adjustment flexibility, while the areal well pattern has a high oil recovery speed.

2. The technical criteria for the areal well pattern

   a. It can adapt to the reservoir distribution, and the injection wells and production wells can control eighty percent to ninety percent of the connected area and reserves. Oil wells can achieve large displacement coefficient and high ultimate recovery after water breakthrough. It can obtain the highest oil recovery with the minimum water production through making full use of the known reservoir parameters, such as permeability, fracture direction, dip angle, and fault and structural form.
   b. With good effect of water injection, the production rate and stable production life can satisfy the requirement and better economic benefits can be achieved. The desired oil production rate and water injection rate can be realized, and the drilled wells can also be made full use of.
   c. It is convenient for the adjustment and management of the development process.

In conclusion, the best mode of water injection should be chosen by comprehensively considering the practical situations of an oilfield, including geological conditions, flow characteristics, and development requirements.

3.2 Well Pattern Optimal Control Theory

The areal well pattern is widely adopted, and geological characteristics and reservoir characteristics have begun to be taken into consideration in the deployment of well patterns. For the irregular well pattern, there are only a few researches on the sedimentary micro-facies, permeability direction, fracture direction, and provenance direction and fewer researches on the well pattern of horizontal wells and multilateral wells. The old concept of well spacing density is not suitable for complex wells, and a new concept is required. Theory of the horizontal well pattern is only focused on the regular well pattern.

At the beginning of the development, the main problems are centered on the following aspects: The existing well patterns are not well applied to deal with reservoir heterogeneity, and a large number of low-production wells are affecting the development benefits. Invalid water injection is serious in the well pattern, and high permeable channels tend to appear, which aggravates areal problems. At the late development stage, the main problems are centered around the following aspects: The recovery degree is high, with only a small number of residual recoverable reserves; there is little potential of liquid extract; the proportion of oil and water wells is big in the high water cut period; interlayer interference is serious, the distribution structure of formation pressure is unreasonable, and the formation pressure of potential layers (sections) is kept at a low level; the conditions of oil and water wells gradually aggravate, and the proportion of low-yield and low-effect production wells is growing; when an oilfield is in the extra-high water cut period, the residual oil has the characteristics of "thin, scattered, little, bad and low."

3.2.1 Problems of the Areal Well Pattern

1. The problems in the development process of the areal well pattern

At present, most oilfields in China and other countries have adopted the areal well pattern system, especially the five-spot well pattern and inverted nine-spot well pattern, and sometimes the cutting water injection. These oil and water wells are evenly located in the oilfield. All kinds of water injection mode can achieve good development effect under the condition of large areas of reservoir distribution, weak heterogeneity, a perfect injection-production system, and plenty of drilling, only through which can the reserves be controlled effectively. In fact, the majority of reservoirs are characterized by serious heterogeneity, instability reservoir distribution, differences in sedimentary micro-facies in different oil layers, and disconnection between different micro-facies transition zones, which cause great difficulty to oilfield development. According to the experience of developed reservoirs, the conventional well pattern cannot achieve the desired effect and the injection-production system is imperfect. Only some oil wells in good reservoirs will achieve high-production efficiency, but most wells have a low production for various reasons.

In the following, an analysis is made of the inadaptability of the areal well pattern for heterogeneous reservoirs, to be specific, fractured sandstone reservoirs. In such reservoirs, almost all well patterns are square inverted nine-spot well patterns commonly used in regular sandstone reservoirs. Because of the disadvantageous influences of fractures on development, the wells are deployed with the well array direction not consistent with the fracture direction, such as Fuyu Oilfield, Chaoyanggou Oilfield, and Toutai Oilfield, with an angle of 0°, 11.5°, 22.5°, and 45°, respectively. Because of the complexity of factor system, some of oil and water wells are located in a fracture system, so there will appear the following phenomena: Early water breakthrough and water cut, even serious water flooding, soon occur in oil wells parallel or nearly parallel to the fracture; due to the non-uniformity of the oil and water movement, especially in the case of serious water flooding, it not only greatly affects the oilfield production stability, but also has serious consequences for oilfield development. Even if linear water injection is adopted instead, it can reduce the water cut and increase oil production to a certain extent, but it cannot fundamentally eliminate the harm caused by the unreasonable well pattern.

Well pattern deployment in Fuyu Oilfield, due to undetermined fracture direction and unreasonable well array, has made east–west production wells flooded after water injection. Because the injection pressure exceeded the fracture pressure, it damaged the casing of oil and water wells, so infill wells or linear water injection had to be utilized to increase oil production.

In Chaoyanggou Oilfield well pattern deployment, people learned the lesson of Fuyu Oilfield and set the angle between the well array and fracture direction as 11.5° or 22.5°. However, because the well array with three other well arrays in between and the well array with another well row in between were located along the fracture direction, and the water well array was nearly parallel to the fracture, there was a big difference of water cut between different oil wells. Even if the linear water injection was used instead, the oil wells' water cut increased rapidly as the injection time increased because of the major reservoir' high permeability, good connectivity, and the interaction between the high water absorption of the matrix and the high conductivity of the fracture. In the main block, for example, the water cut rose from 10.8 % at the end of 1997 to 37.9 % in September 1998, and the monthly water cut rose by 3 %. The daily oil production dropped from 442.3 to 306.7 t, with a monthly decrease of more than 3.4 %. Too much injection water made water cut rise rapidly, the invalid injection water increased, and then oil production declined with it.

In the well deployment of Toutai Oilfield, the well array was arranged with a clockwise rotation of 45°. Because of the poor reservoir physical property, high fracture permeability, and long distance of the well array, it made water circulate between the oil wells and water wells after water injection. On the one hand, it led to serious water flooding in east–west oil wells. For example, from 1994, when water injection began, to 1996, the number of water out wells was fifty five, accounting for 23.8 % of the total oil wells. On the other hand, the formation pressure dropped and the oil production decreased quickly. Turning to the linear waterflooding caused the production decrease and bad development effect because of the poor improvement of formation pressure.

Obviously, for the fractured low-permeability sandstone reservoir, the fracture shows obvious directivity in the process of waterflooding. On the whole, the inverted nine-spot well pattern is difficult to adapt to low-permeability sandstone reservoirs.

2. The problems of the areal well pattern in the late development period

   a. High degree of reservoir recovery of recoverable reserves and low remaining recoverable reserves. At the late stage of oilfield development, oilfield recovery reaches 30–35 % and the recovery of recoverable reserves reaches 70–80 %, some even higher.
   b. At the high water cut stage, the liquid production rate and water injection capacity are close to the reasonable economic limit with high-efficient recovery techniques, which results in small potential for oil production by means of well extract.
   c. The injector-producer ratio is high in the late period of high water cut development, generally up to 1.5–2.0. The oil wells improved by multi-directional injection account for a small proportion. For example, the percentage is only 45.5 % in Shuanghe Oilfield. The adaptability of remaining oil development in thick layers is poor. Therefore, it is hard to meet the requirements of water injection, structural adjustment of liquid production, and tertiary recovery in the thick oil layers at the late development stage.
   d. The interlayer and intralayer interference is serious, and distribution structure of formation pressure is unreasonable with low levels of potential layer and section, and it is difficult to supplement displacement energy. The production of new wells declines rapidly with short stable production life.
   e. The conditions of oil and water wells become worse gradually, the proportion of low-productivity and low-efficient wells is increasing, which seriously restricts the oilfield development.
   f. In the late development period with superhigh water cut, the remaining oil has the characteristics of "thin, scattered, little, bad, and low." The reservoir heterogeneity affects the balance of water flooding, which causes the differences of remaining oil distribution between the high-permeability layer, low-permeability layer, high-permeability zone, and low-permeability zone. For a uniform areal well pattern, the remaining oil is distributed sporadically, as shown in Figs. 3.7, 3.8, and 3.9.

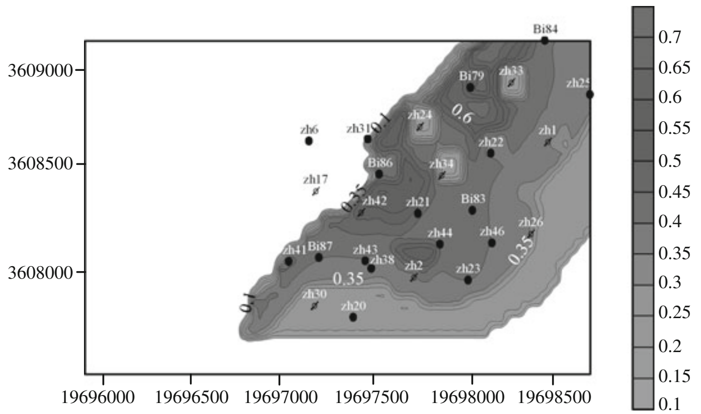


Fig. 3.7 Recovering oil distribution in Zhao'ao IV3$^{1(4)}$ layer

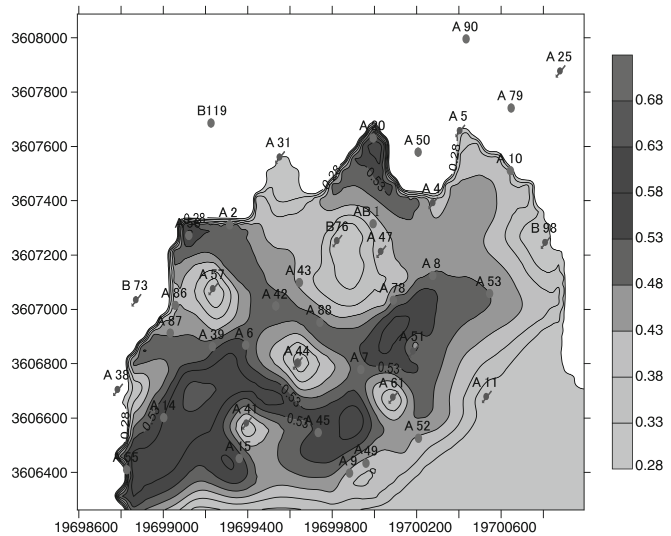


Fig. 3.8 Recovering oil distribution in Anpeng IV$^{2(2)}$ layer

g. The advantageous flow channel is easily formed, and the reservoir is displaced unevenly. Due to long-term water injection development, the reservoir properties change greatly. In the vicinity of the wellbores, there appear large intake volume and little remaining oil after long-term waterflushing of injection water. It is easy for advantageous seepage channels to form between the wells, which affects water flooding efficiency. The formation of advantageous flow channels is one of the serious problems of water drive at the late stage of oilfield development.

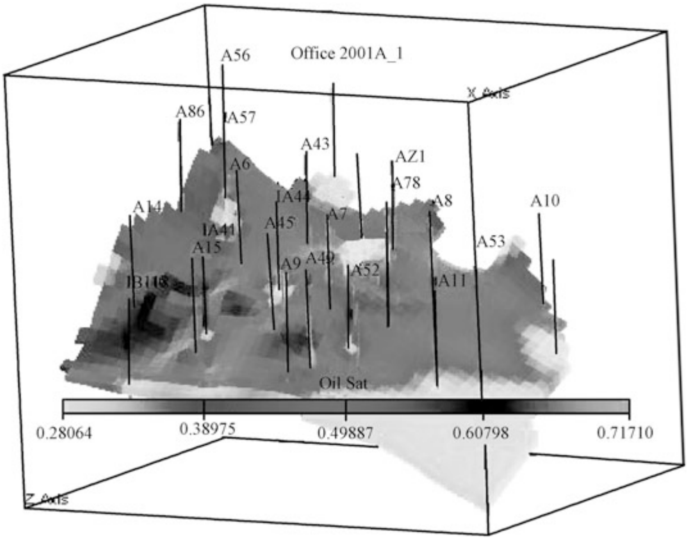


Fig. 3.9 Remaining oil distribution in Anpeng H3IV2$^{1-3}$ layer

h. Microscopic remaining oil is locally concentrated due to the reservoir microscopic heterogeneity. For a reservoir with poor sorting and serious microscopic heterogeneity, the water flooding efficiency is low, with the injection water flowing through big holes and bypassing small holes or throats. Therefore, there exists a large amount of microscopic remaining oil, which cannot be produced in the current well pattern.

3. The problems in the areal well pattern deployment

   a. It leaves reservoir heterogeneity and anisotropy K_x and K_y out of consideration. The areal well pattern has been adopted for a lot of large- or medium-sized sandstone reservoirs in China without reservoir heterogeneity taken into consideration in practical well deployment. No matter how reservoir permeability is, the well patterns are evenly distributed, which causes big differences in the production of oil well and the amount of injection water between reservoirs with different permeability values. Therefore, the corresponding relationship between producers and injectors is unclear, so it cannot ensure that the injection water drives oil evenly. If the same well pattern is used in both high-permeability zones and low-permeability zones, it will result in water breakthrough in high-permeability zones ahead of low-permeability zones and big flow channels, the latter of which are one of main problems for enhancing waterflooding efficiency at the late development stage.

b. It leaves sedimentary characteristics out of consideration in well pattern arrangement. It is the development of modern technology of fine reservoir description that helps people recognize reservoir distribution and reservoir sedimentary characteristics accurately. There are big differences of reservoir properties between different sedimentary micro-facies. For example, permeability varies considerably in channel deposits and natural levees. However, the uniform well pattern is usually used in well deployment without the optimization of well spacing density taken into consideration; i.e., there is no distinction between the blocks which need different well spacing densities, big or small. Meantime, water drive direction has an important effect on waterflooding efficiency, which is proved by actual oilfield development. In fact, however, sedimentary characteristics are not taken into consideration in many well pattern arrangements, which lead to the failure of optimal control of well patterns and of the best waterflooding efficiency.
c. The definition of well spacing density is not suitable for new well types. The current definition refers to the area controlled by a single well or the number of wells per unit area, which is based on the vertical wells. However, many new drilling technologies have emerged, such as the technology for highly deviated well, directional well, horizontal well, multilateral well, and other well types, whose purpose is to increase the openness and the reserve control. Obviously, the previous definition of well spacing density is not appropriate for the new well types. How to define the basic concept of the new well spacing density and design the suitable well pattern or well type combination that controls reserves optimally is an important problem which needs to be considered seriously and to be solved quickly.

3.2.2 Concept of Well Pattern Optimal Control

At present, most oilfields in China and other countries adopt the areal well pattern system, especially the five-spot well pattern and inverted nine-spot well pattern, and sometimes cutting water injection. These oil and water wells are evenly located in the oilfield. To achieve the goal of high water injection uniformity and effective control of reserves, there must be a prerequisite: large areas of reservoir distribution, weak heterogeneity, perfect injection-production system, and plenty of drilling. In fact, however, the majority of actual reservoirs are characterized by serious heterogeneity, instable reservoir distribution, differences between sedimentary micro-facies, and disconnection between different micro-facies transition zones, which bring great difficulties to oilfield development. According to the experience of developed reservoirs, the conventional well pattern cannot achieve the desired effect and the injection-production system is imperfect. Only some oil wells in good reservoirs will achieve high-production efficiency, but most wells have a low production for various reasons. It is quite often the case in many onshore oilfields. The production efficiency in Suizhong 36-1 and Jinzhou 9-3 in the Bohai Sea offshore region and Qinhuangdao Oilfield is not optimistic, either. It is the development of modern technology of fine reservoir description that helps people recognize reservoirs more deeply and accurately. The conventional theory of the areal well pattern cannot catch up the progress of modern oilfield exploitation. The well spacing definition that area controlled by a single well or the number wells per unit area does not apply to advanced and complex wells. Due to the restriction of Shelkachev's formula, the technical and economic limit formula about well spacing density derived from the formula is also limited. Therefore, with reservoir description as the basis, the maximum reserve control as the prerequisite and the improvement of the single well efficiency as the goal, theory of optimal control of modern well patterns is put forward in this book. It will break through the conventional way of well spacing and bring greater benefits to oilfields.

1. The purpose and requirement of well pattern optimization control

The existing problems in the development process of the current well patterns and the new technology of reservoir description and drilling help people have a better understanding of oil reservoirs. High oil production, effective reserve control, and great degree of recovery speed can be realized with fewer wells with the new drilling technology. Therefore, the concept of well pattern optimal control is put forward in this book. This theory is based on reservoir description, reservoir distribution, and remaining oil distribution. With reserve control as the prerequisite, this theory aims to optimize the well pattern arrangement for improving the single well efficiency.

According to theory of well pattern optimal control, the oil and water wells are arranged based on reservoir geological characteristics, such as the distribution of sedimentary micro-facies and permeability. It utilizes modern complex well technology to maximize the control reserves and the economic benefits. Its specific performance is as follows.

a. Maximize the proportion of drilling oil sand bodies and establish a good corresponding relationship between injection and production in oil sand bodies;
b. Maximize the control reserves of a single well and drainage area by using complex well type technology;
c. The reasonable well spacing is determined in accordance with reservoir heterogeneity. Permeability grade and sedimentary micro-facies are mainly used to divide blocks and then arrange the well pattern. For the block with high permeability and weak heterogeneity, like the main channel with good physical properties, the large well spacing pattern is used. Figure 3.10 shows the relation curve between permeability and drainage radius. A conclusion can be drawn that the greater the permeability, the larger the drainage radius.
d. The vector well pattern arrangement. The vector well pattern means that the well pattern is arranged according to the following factors appropriate to it: the sedimentary source direction and river or main permeability direction. Namely,

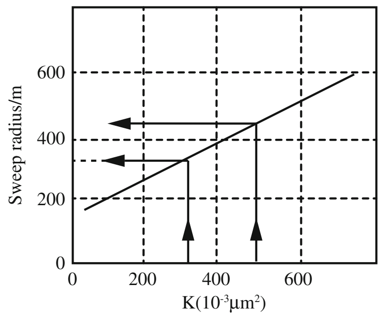


Fig. 3.10 Relationship between drainage radius and reservoir permeability

it is a synthesized well pattern arrangement based on a comprehensive consideration of reservoir distribution, provenance direction, river or main permeability direction, fracture direction, and sedimentary micro-facies.

2. The difference between well pattern optimal control and conventional well pattern

In the production process, the well pattern type is mainly controlled by the geological characteristics of oil and gas fields. According to the geometrical shapes of the well pattern, the actual well pattern types are generally divided into irregular well patterns and regular well patterns. In oilfield development, the regular well pattern generally refers to the areal well pattern. The common areal well pattern consists of the following types: the linear well pattern, staggered linear well pattern, four-spot well pattern, seven-spot well pattern, nine-spot well pattern, inverted nine-spot well, etc. The irregular well pattern is generally the transformation of the regular well pattern.

Cutting water injection is suitable for the following conditions:

a. The reservoir is characterized by a large and stable distribution (the oil layers extend with a certain length). The injection line can form a relatively complete cutting line.
b. There is a good connection between production wells and injection wells in one cutting area.
c. The reservoir has a certain flow coefficient to ensure that the injection water is delivered to the production well array from the injection well array to achieve the required production rate in a certain cutting area and well spacing.

Water injection of the areal well pattern is suitable for the following conditions:

a. Large reservoir areas with incomplete structure and complicated faults.
b. The reservoir is distributed irregularly with poor extensibility, mostly in the form of lens. The cutting water injection is unable to control most of the reservoir.
c. The reservoir flow coefficient is low with poor permeability. The effective area and oil production rate by means of cutting water injection are small due to large flow resistance.

d. It is suitable for enhanced recovery at the late stage of an oilfield.
e. It is especially suitable for high-speed production oilfields. To realize good development effect, these conditions must be ensured: a large reservoir area, weak heterogeneity, a complete injection-production system, and plenty of wells drilled. Only in this way can the goal of good reserve control be achieved.

The idea of well pattern optimal control is directed to the reservoir with strong heterogeneity, unstable distribution, differences between sedimentary micro-facies, and disconnection of transitional zones between different micro-facies. This method breaks through the limitations of conventional well patterns and conforms to the reservoir geology to the greatest degree. The well type selection is based on the actual situation, such as the vertical well, directional well, horizontal well, and mixed well with multiple bottom holes.

3.2.3 Summary of Well Pattern Optimal Control

Well pattern optimal control for complex reservoir characteristics has already been discussed in the above. The target of choosing appropriate well type and reasonable deployment of oil and water wells is to effectively control reserves and achieve the best economic benefits. In this control process, the recognition of reservoir geology and development regularity is the foundation. The following will specifically discuss how to implement the optimal control. These calculation processes of the methods will be reported in other chapters or in other books in detail.

1. Selection and determination of the reasonable well pattern

It is a complicated problem to select and determine the reasonable well pattern, which is one of the important tasks in the design of oilfield development. Currently, there are various well patterns, including cutting water injection, pattern flooding, line flooding, spot flooding, uniform well pattern and other transformed well patterns, etc. These well patterns are summarized from the actual application process. In actual applications, theory of reasonable well pattern optimal control should be applied to choose the right well pattern, without copying the existing results. Therefore, there are several aspects that should be considered in the choice of well patterns.

a. The geological characteristics of the reservoir should be fully recognized, mainly including the characteristics of reservoir distribution, sedimentary micro-facies, and characteristics of reservoir directions. The selection of waterflooding direction and well array directions should match the characteristics of reservoir directions in the same micro-facies and layers to achieve the best effect of water flooding.
b. One series of layer matches one set of well pattern. The selection of well pattern should match reservoir characteristics in the same layer system. For the reservoir with multiple layer system, different well patterns can be selected according to

the production sequence, or advanced wellbore technology can be utilized to improve the well efficiency.

c. Geographical impact should be considered reasonably and the requirement of well pattern depends on the location of the oilfield. In the desert or ocean district, fewer wells should be drilled due to the high cost. In addition, effective well types and well patterns should be chosen to control underground reserves in the urban areas, lakes, and so on, where drilling is restricted.
d. The economic benefits and production scales should be taken into consideration. The reasonable well pattern type is consistent with reasonable well spacing density, and the specific method will be discussed in chapter eight. It shows that the production scale and economic benefits must be obtained after well pattern arrangement. Otherwise, it would be meaningless. The production scale should be ensured in order to guarantee the scale benefits and social benefits even under the condition of undesired economic benefits.
e. Effective utilization of oil resources. Because crude oil is a kind of non-renewable energy, which plays an important role in the development of society and economy, the effective utilization of oil resources should be carefully considered in all reasonable development optimal controls. For each oilfield development, the purpose of optimal control is to maximize economic benefits, considering resource constraints without destructive production at the same time.
f. Attention should be paid to environment protection. As mass industrial production, oilfield development is generally conducted in the natural environment, occupying farmlands and emitting pollution, etc. Therefore, environmental protection is particularly important in the well pattern optimal control.

2. Determination of a reasonable injection-production system

The well pattern is an important means to open the reservoir and produce oil directly. Under a certain condition of the well pattern, it is also a part of well pattern optimal control how to make more crude oil inflow to production wells or how to make injected water drive oil and supplement energy effectively. Even in the best well pattern, it cannot reach the best development effect without reasonable working system and pressure system. Reasonable injection-production system includes the following several aspects.

a. Determination of a reasonable pressure system. A reasonable pressure system is the foundation of the rational flow of reservoir fluid. The pressure system includes reasonable production pressure difference, reasonable bottom-hole flow pressure, reasonable injection-production pressure, and so on. These values can be calculated in accordance with the reservoir characteristics and the corresponding analysis of the well pattern. Of course, the above values are also associated with the technology and reservoir characteristics, especially the development strategy based on the overall exploitation strategy of oilfields.

b. Determination of a reasonable oil production rate. It provides basic guarantee of the best recovery in normal development of oilfields. Due to the restriction of reservoir characteristics, it not only limits the single well production, but also determines oil production rate. Oil production rate is more often determined by the development strategy, but restricted by reservoir capacity. Destructive exploitation for short-term effect is forbidden. The best value of oil production rate can be determined by development test or numerical simulation, and at such a rate, a reservoir can be operated efficiently.
c. Reasonable injection-production ratio. It includes two meanings: One is reasonable injector-producer ratio which the oil production intensity increases with the value; the other is ratio of injected water to produce liquid—the formation pressure increases when the value is greater than 1, and the drainage quantity can also be increased to increase production through enlarging producing pressure difference. No matter which method is adopted, there are two possibilities: to improve the development effect or have no benefits. Therefore, reasonable injection-production parameters have important effects on well pattern optimal control.
d. Reasonable working system. Well pattern optimal control ultimately relies on every well, at which all design parameters must be directed. The well pattern control can be optimized by a reasonable working system, including production wells and injection wells.

3. Determination of the reasonable well type

With the progress of drilling technology, there are various methods to open a reservoir. In order to increase the openness of a reservoir, different well types are developed rapidly, including the vertical well, horizontal well, multilateral well, step horizontal well, and arc horizontal well. Different well types are applied to different reservoirs and reservoir characteristics, and its target is to open the reservoir better and control more reserves to achieve high production. The reasonable well type is one of the important means to get multiple effects.

a. Selection principle for well types. There is no doubt that oil production increases with the openness of a reservoir, which is the purpose of drilling. All methods should conform to two aspects: The control reserves should be reasonable, which is beneficial to the final degree of reserve recovery degree. The drilled and shooted reservoir is the more the better. Meanwhile, the following factors have an impact on well type selection: the development mode, recovery strategy, development technology, investment, and so on. In general, the vertical well is more suitable for a thick reservoir or a reservoir with multiple layers. Because horizontal wells and multilateral wells can greatly increase the reservoir control, these new well types are strongly recommended.
b. The adaptability of different well types. Different well types are suitable to different reservoirs, and its adaptability is also decided by reservoir characteristics. Due to the large number of reservoir types, reasonable well types for different reservoirs will be elaborated in chapter four. Of course, with the

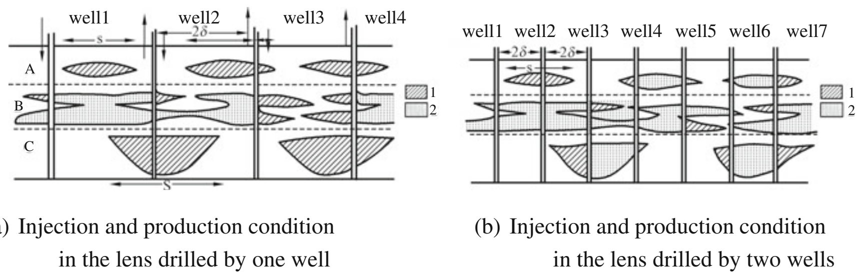
progress of drilling technology, new well types can now meet the needs of almost all kinds of reservoir; e.g., the horizontal well is suitable for all reservoirs. For most of the low-permeability reservoirs, horizontal wells with fracturing process must be utilized.

3.3 Principles and Standards for Well Pattern Optimal Control

3.3.1 Principles for Well Pattern Optimal Control

In fact, well spacing density of production wells and their arrangement have an important effect on the initiative and flexibility of oilfield development. Reasonable well patterns should be determined according to oil layer distribution, with oilfield geology, fluid mechanics, and economic theory taken into account, to analyze the development effect of different well patterns and choose the best scheme.

The more wells are drilled and the well spacing density is the higher. And the higher degree of reservoir control is obtained. It is favorable to high and stable production and to the increase of oil recovery rate for the whole oilfield. The Oil and Gas Institute of the former Soviet Union has studied the relationship between oil reserves loss and well spacing for Romashkino Oilfield. The study shows that the loss of crude oil is 5 % when the well spacing is 1000 m, while the value is up to 10 % when well spacing is 2000 m, and this relation is also proved in Du Mazzy Oilfield. Figure 3.11 describes the underground conditions of this oilfield, which is composed of three layers. Layer A consists of some isolated oil sand bodies, layer B



(a) Injection and production condition in the lens drilled by one well

(b) Injection and production condition in the lens drilled by two wells

(1—unwashed sandstone; 2—washed sandstone)

Fig. 3.11 Reservoir status in Du Mazzy Oilfield

Table 3.3 Relationship between the well pattern and recovery

Oilfield	Oil recovery under different well spacing density (km^2/well)					
	0.02	0.10	0.20	0.30	0.50	1.00
East Texas in the USA (Ude Bein)	0.80	0.78	0.76	0.73	0.70	0.59
Bavly Oilfield in former Soviet Union (a certain layer)	0.74	0.72	0.69	0.67	0.63	0.52
Du Mazzy Oilfield in former Soviet Union (a certain layer)	0.69	0.65	0.60	0.56	0.51	0.33
Romashkino Oilfield in former Soviet Union Abdullah Manrow district (a certain layer)	0.68	0.62	0.55	0.48	0.43	0.21

has a good connectivity, and layer C is composed of thick and poor extension oil sand bodies. If well 1 is a water injection well, the lens in layer A and layer C cannot be influenced by injection water in the process of development. If the formation pressure is lower than the saturation pressure, the well can only rely on dissolved gas to produce a small amount of oil from these lenses. The production will be higher if the well spacing is reduced by half, and the gradual inward shift of oil–water line is adopted; namely, the first well array is turned into injection wells after water breakthrough and the second, and so on. It is clear that the remaining oil area is reduced obviously in the second case. This shows that well spacing density has an important effect on crude oil recovery in a reservoir composed of many lenses, which is different from homogeneous reservoir with stable distribution.

V.N. Shelkachev, a scholar of the former Soviet Union, has analyzed the relationship between ultimate recovery and well spacing density. His research proves that when the well spacing density increases from 1 km^2/well to 0.02 km^2/well, the ultimate recovery increases by 21–47 % in different reservoirs, as shown in Table 3.3.

Martov et al., scholars of the former Soviet Union, have analyzed the actual data of 130 reservoirs at the stage of late development and obtained the relation table between recovery, and well spacing density and flow coefficient, as shown in Table 3.4. The result proves that the oil recovery increases more or less with different well spacing density values. The smaller the flow coefficient, the greater the impact of well spacing density. This is because the smaller the water well spacing and the better the layer continuity, the higher the water out coefficient and oil recovery.

It should also be pointed out that there is no obvious increase of control reserves when the well spacing density increases to a certain extent. On the contrary, it will aggravate the interwell interference, which reduces the single well production and economic effect. What's more, the management and workover of oil and water wells will increase significantly.

The principle for well pattern optimal control includes mainly the following aspects:

Table 3.4 Relationship between well spacing density and recovery with different flow coefficients

Reservoir groups	Flow coefficient 100×10^{-3} μm² m/mPa s	Reservoir number	Correlation coefficient	Dependent equation	Reservoir characteristics
1	>50	23	0.863	$\eta = 0.785 - 0.005f + 0.00005f^2$	Stable distribution High permeability
2	10–50	45	0.880	$\eta = 0.73 - 0.0065f + 0.00003f^2$	Stable distribution High permeability
3	5–10	24	0.841	$\eta = 0.645 - 0.007f + 0.00035f^2$	Unstable distribution
4	1–5	24	0.858	$\eta = 0.563 - 0.005f + 0.000016f^2$	Unstable distribution
5	<1	14	0.929	$\eta = 0.423 - 0.0088f + 0.000073f^2$	Carbonate reservoir

Annotation: f is well spacing density, km²/well

a. The well pattern should adapt to the reservoir distribution as much as possible to control more reserves;
b. The well pattern arrangement should achieve the following goals: sufficient injection water effect in the main layers, the prescribed production rate, and long-term stable production life;
c. The well pattern should have high sweep efficiency and reach the balance between injection and production;
d. The well pattern will be helpful for the development adjustment in the future, and each set of well patterns should also be in coordination for the case of comprehensive utilization at the late stage;
e. Different oil sand bodies and properties need different reasonable well spacing density. Their density should be determined by the characteristics of different regions and blocks, and the wells should be arranged vectorially;
f. Based on the above requirements, good economic and investment effects with low costs should be achieved; and
g. The well pattern should be determined with advanced production technology in a practical way.

The above points are technical aspects of well pattern optimal control. To achieve the goal of optimal development of the overall reservoir, effective utilization of resources and environmental protection should be ensured in the implementation of well pattern optimal control.

3.3.2 Standards for Well Pattern Optimal Control

The indexes reflecting the quality of well pattern include the following aspects, such as the drilling ratio of sand bodies, reserve control degree, waterflooding control degree, and oil production rate. They are directly related to the effect of well pattern arrangement. Of course, there are also many technical indexes about well pattern itself, such as well spacing density, producer-injector ratio, and control reserves of a single well. These values should be determined as reasonably as possible for a specific oilfield. Therefore, before well pattern deployment, all kinds of studies of the reservoir, especially reservoir fine description, need to be conducted, through which we can fully understand the planar and vertical distribution of oil layers and oil sand bodies, analyze the extend directions of sand bodies, and calculate their length and area. All these lay a solid foundation for well pattern deployment, on the basis of which the standard for well pattern deployment can be worked out according to the requirements for high-effective development of actual reservoirs at different development stages (the initial stage, the middle stage, and the high water cut stage).

a. The initial development stage

The drilling ratio of sand bodies ≥80 %,
The reserve control degree ≥85 %,
The control degree of waterflooding ≥80 %, and
Oil production rate ≥2 %.

b. The middle development stage

The drilling ratio of sand bodies ≥90 %,
The reserve control degree ≥90 %,
The control degree of waterflooding ≥85 %, and
The oil production rate ≥2 %.

c. The high water cut development stage

The drilling ratio of sand bodies ≥95 %,
The reserve control degree ≥95 %,
The control degree of waterflooding ≥90 %, and
The oil production rate ≥1 %.

Due to different heterogeneity of reservoirs and different cognition degree, combined with different physical properties of the reservoir and fluid, the standards for well pattern deployment should also be different.

3.3.3 Implementation of Well Pattern Optimal Control

In the process of oilfield development, the well pattern optimal control is a systematic project. In addition to the well pattern itself, it also involves geologic knowledge, coordination of the injection-production system, the single well working system, etc. Because there are so many influencing factors, we should consider the main problems in concrete implementation, together with the specific characteristics of reservoir geology and performance characteristics of development. And then, we can optimize the well pattern, well type, injection-production system, and single well working system to realize the overall well pattern optimal control consequently.

For the reservoirs developed or to be developed, the implementation ideas vary a little difference, which are discussed step by step in the following. For the reservoir to be developed, the main steps of well pattern optimal control are as follows.

a. Fine understanding of reservoirs

Geological information, which is directly related to well pattern deployment, includes structure features, reservoir type, reservoir characteristics, sedimentary micro-facies, reservoir distribution characteristics, and oil and water distribution. The most important information is the directional characteristics of the overall and local reservoir, which have been detailed in the above. All the information is the geological basis of well pattern optimal control.

b. Selection of reasonable well patterns and well types according to reservoir characteristics

The reasonable well spacing density and productivity can be calculated by reservoir engineering method. Based on the reservoir characteristics, suitable well types and well pattern deployment modes can be determined according to the method detailed in other chapters. The well pattern deployment should meet the technical standards and principle for well pattern control. The directional features of the reservoir should be consistent with well pattern characteristics. Of course, the determination of well patterns and well types is the key to the process of the optimal control.

c. Technical policy limits based on the reasonable development of well pattern arrangement

Reservoir engineering and numerical simulation method should be utilized to choose reasonable technical policy limits after the determination of the well pattern and well type to ensure that the selected well pattern can reach the best control degree of waterflooding and its effect.

d. Simulated development

Simulated development can be conducted by numerical simulation method to make a judgment of well pattern and development technical policy limits. If the result does not lead to the desired development effect, then corresponding parameters need to be modified; otherwise, the next step can be carried out.

e. Modification of the optimal control parameters

There are a lot of control parameters about well pattern optimization, as dwelt on in the above. The main parameters include systematical well pattern parameters, production parameters (the injection-production ratio, injection pressure, etc.), and the single well working system. Well pattern control can be optimized through adjusting the system parameters; otherwise, a reasonable well pattern must be reselected according to the reservoir.

The specific control process is shown in Fig. 3.12.

For an old oilfield, the main steps of well pattern optimal control are as follows.

a. Fine understanding of reservoirs

For a developed oilfield, there is too much information about geological reservoir obtained from old wells, on which the well pattern adjustment is based. Geological information, which is directly related to well pattern deployment, includes structure features, reservoir types, reservoir characteristics, sedimentary micro-facies, reservoir distribution characteristics, and oil and water distribution. The most important information is the directional characteristics of the overall and

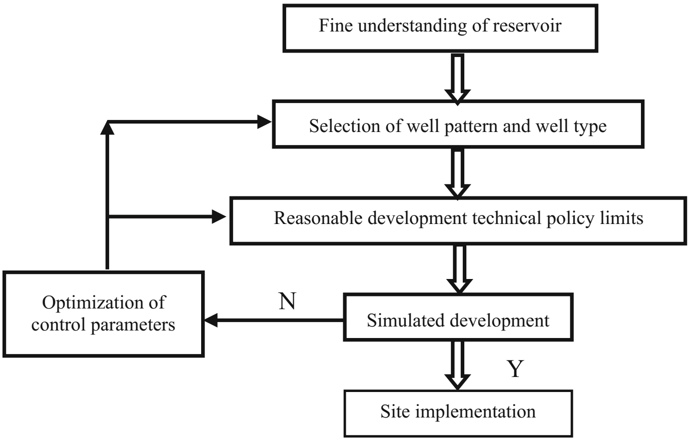


Fig. 3.12 Flowchart of well pattern optimal control for a new oilfield

local reservoir, which have been detailed in the above. All the information constitutes the geological basis of well pattern optimal control.

b. Adaptability evaluation of the current well pattern

A question should be asked about the current well pattern that has already been deployed for a developed reservoir: Whether or not it meets the requirements and standards for well pattern optimal control, whether or not it matches the reservoir characteristics and reaches the desired development effect, and so on. About these aspects, a systematical evaluation and analysis of well pattern adaptability are needed. If there are no problems, what is needed is only to improve and perfect the well pattern in the late-stage adjustment gradually. Otherwise, overall adjustment and deployment should be carried out from the perspective of well pattern optimization. This process needs to be combined with the well pattern control of newly developed reservoirs.

c. The distribution law of remaining oil

The purpose of the well pattern optimal adjustment in late development is increasing production. How and from where to realize this expectation is an important issue. It is necessary to recognize the law of remaining oil distribution, enrichment mode, and control factors at the current phase, on the basis of which the mode, target, and specific control parameters of well pattern optimal control can be determined.

d. Selection of well pattern optimal control mode

After evaluating the well pattern adaptability and recognizing the characteristics of remaining oil distribution, it is necessary to determine the corresponding mode of well pattern optimal control, mainly including:

- Infill new wells in the existing well pattern and lay down the reasonable technical policy limits and the single well working system and so on, which is the simplest mode;
- The following work can be done according to the characteristics of reservoir and remaining oil distribution, and the standards and requirements of well pattern optimal control: a partial change of the local well pattern, drilling some adjustment wells, mutual transformation of the production well and injection well, and altering the direction of waterflooding, etc.; and
- Utilize the existing well pattern as much as possible to change the overall control mode, including drilling new wells, selecting a new well type, changing waterflooding method, and adopting different well pattern control modes for different kinds of remaining oil distribution, that is, comprehensively changing the well pattern mode in accordance with the standards and requirements of well pattern optimal control. Moreover, it is necessary to calculate the reasonable well spacing density through the reservoir engineering method, choose an appropriate well type from the perspective of the reservoir characteristics, and determine the well pattern deployment mode and well type according to the methods detailed in other chapters.

e. Technical policy limits based on the reasonable development of well pattern arrangement

Reservoir engineering and numerical simulation method should be utilized to choose reasonable technical policy limits after the determination of the well pattern and well type to ensure that the selected well pattern can reach the best control degree of waterflooding and its effect.

f. Simulated development

Simulated development can be conducted by numerical simulation method to make a judgment of the current well pattern and development technical policy limits. If the result does not lead to the desired development effect, then corresponding parameters need to be modified; otherwise, the next step can be carried out.

g. Modify the optimal control parameters

There are a lot of control parameters about well pattern optimization, as dwelt on in the above. The main parameters include systematical well pattern parameters, production parameters (the injection-production ratio, injection pressure, etc.), and the single well working system. Well pattern control can be optimized through adjusting the system parameters; otherwise, a reasonable well pattern must be reselected according to the reservoir.

The specific control process is shown in Fig. 3.13.

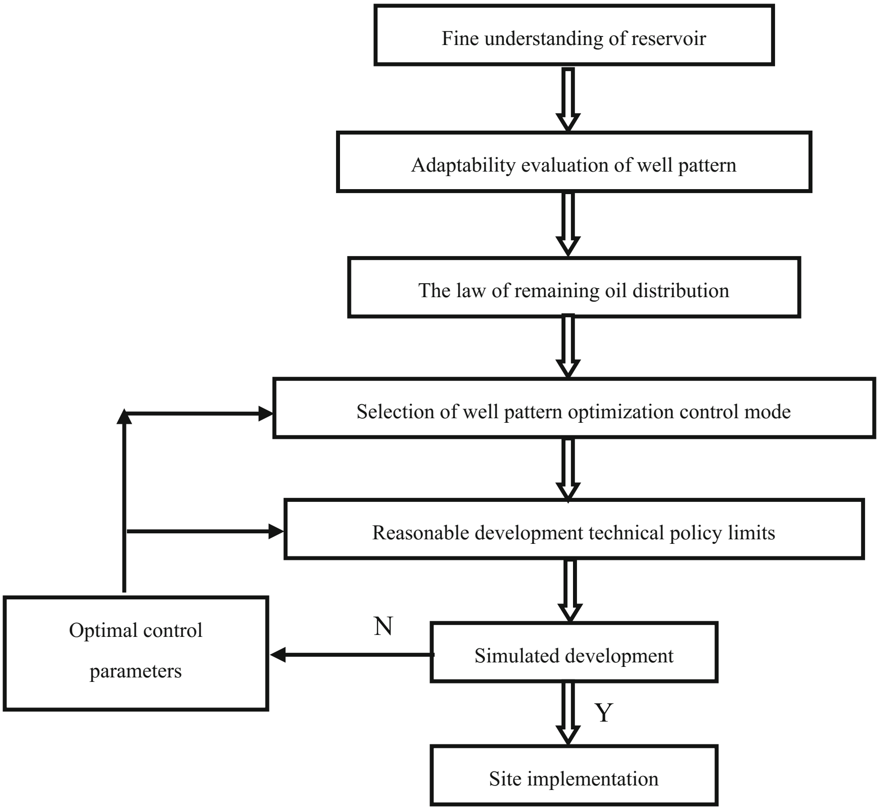


Fig. 3.13 Flowchart of well pattern optimal control for an old well

3.4 Influence Factor Analysis of Well Pattern Optimal Control

Well spacing density, which is influenced by reservoir properties, oil properties, and production technology, is one of the important factors that influence technical and economic indicators in oilfield development. The well spacing density changes with different stages of oilfield development. For well pattern optimal control, the geological factors of reservoirs, which mainly include the characteristics of reservoir distribution, structural features, heterogeneity, physical properties of crude oil, development strategy, geographical environment, etc., must also be taken into consideration. In the following, an analysis is made of the main factors that influence well pattern control, including the following aspects.

3.4.1 Reservoir Distribution Characteristics

The distribution characteristics of oil reservoir have a direct influence on the well pattern deployment. If the reservoir is composed of many sets of oil layers in vertical, it has a certain quantity of reserves, which can form the industrial oil flow. In this case, each well pattern should be optimized separately. For this kind reservoir with multiple layers, we can adopt different strategies according to their respective characteristics: to produce oil in different layer groups by the upward layer-by-layer method with one set of well patterns and to adopt the method of separate production and commingled injection.

Figure 3.14 shows the diagrammatic cross section of typical oil sand bodies, which look like lens with a flattop and convex bottom and two asymmetric sides. Semiconnection is the dominant way in their internal structure, and point contact is the dominant way between them. In most cases, there is no connection between the sand bodies. The control of sand bodies must be considered in well pattern deployment. A coherent injection-production system or the single well control should be adopted on the basis of the sand bodies; otherwise, it will cause loss of reserves where the sand bodies are not drilled. In the process of waterflooding, injection and production should correspond to each other. If there is no production or injection, a desirable water flooding control cannot be achieved. Therefore, the sand body size and connection must be considered in well pattern deployment.

The distribution and size of oil sand bodies are the basis for designing well spacing, and it should be based on the size of main sand bodies. When the length and width of sand bodies are 300 and 200 m, respectively, the well spacing should be less than 300 m. The well spacing design in actual well pattern arrangement should be based on the calculation and analysis of the sand body distribution and the control degree of water flooding with different well spacing patterns. The control degree of water flooding must be greater than 70 % after the deployment. Figure 3.15 shows the oil sand body distribution in an oilfield. Various sizes of oil sand bodies are represented by deep colors. As a kind of reservoir, the oil sand bodies are distributed discontinuously on the plane. In the design of well spacing, overall consideration is required. The first-class reservoir is the key object of well pattern control and the second-class reservoir, etc., should be dealt with in different

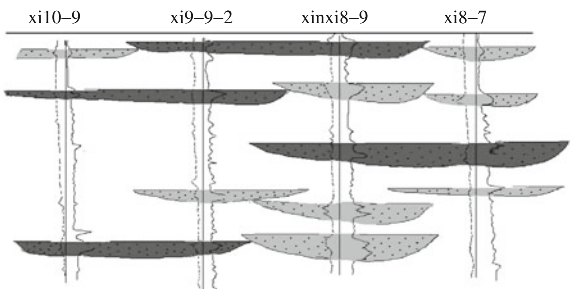


Fig. 3.14 Diagrammatic cross section of typical oil sand bodies

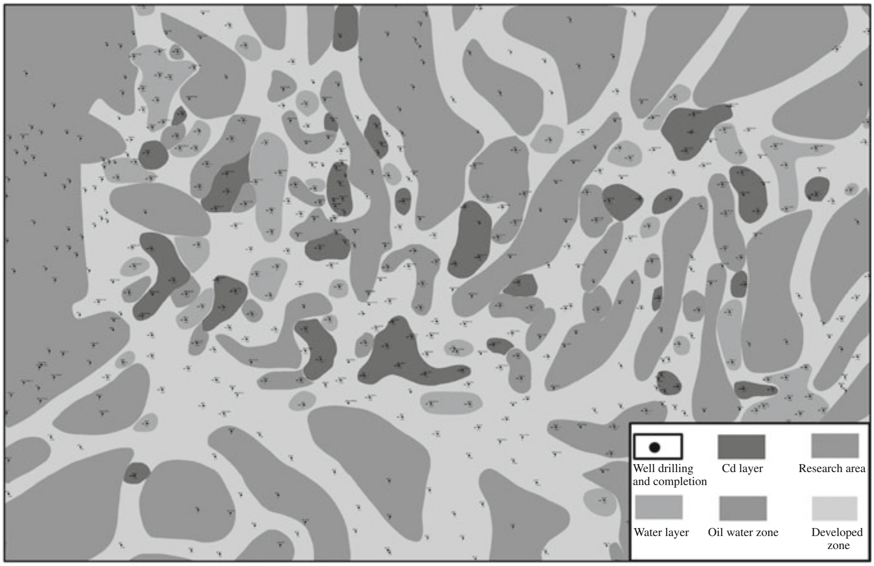


Fig. 3.15 Oil sand body distribution in an oilfield

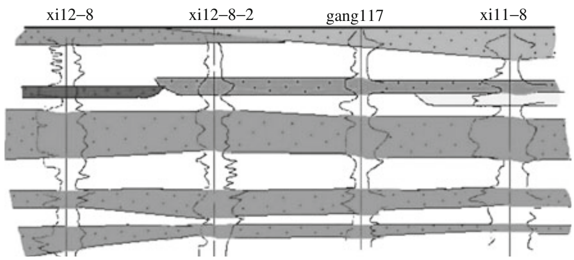


Fig. 3.16 Cross section of a reservoir

ways. Different control strategies should be adopted for production in different types of oil reservoir with overall consideration.

Figure 3.16 represents another type of sand body distribution. The sand body profile, like a strip on the plane, is relatively flat at the top and bottom. The sand bodies are connected mainly in the mode of "extensive connected bodies," typical of the braided river. This kind of sand body, with good continuity, wide distribution, and fine vertical superposition, is suitable for the large and uniform areal well pattern. With all the advantages, the directional characteristics of the reservoir should be considered seriously in the selection of the well array and waterflooding direction, so should the plane heterogeneity of the reservoir in the choice of well spacing density.

3.4.2 Sedimentary Characteristics of the Reservoir

Sedimentary characteristics of the reservoir refer to the characteristics of different sedimentary micro-facies formed due to different sedimentary models in the sedimentary process. As stated earlier, continental sedimentation can be divided into many micro-facies with different physical properties, whose permeability values differ by several times or dozens of times, the river sedimentary facies being the best. The differences will appear in the development process due to different physical properties of sedimentary micro-facies. So the property differences must be considered in well pattern deployment.

Permeability, porosity, and directional characteristics in sedimentary micro-facies, including the disconnection between different micro-facies, all these influence the well pattern control and waterflooding effect, as shown in Fig. 3.17.

The main micro-facies are composed of river channels and floodplains in Fig. 3.17. Due to the direction of sand bodies of river channels different from floodplain obviously, waterflooding control should be considered separately. Owing to disconnection between different micro-facies, there is not obvious corresponding injection-production relation between different micro-facies, which has been proved by actual developed oilfields. The reasonable direction of waterflooding and well spacing should be determined according to the main seepage direction for the sake of equilibrium displacement. In well pattern deployment, the corresponding relation between injection and production should be improved to achieve a good waterflooding effect according to different characteristics of micro-facies.

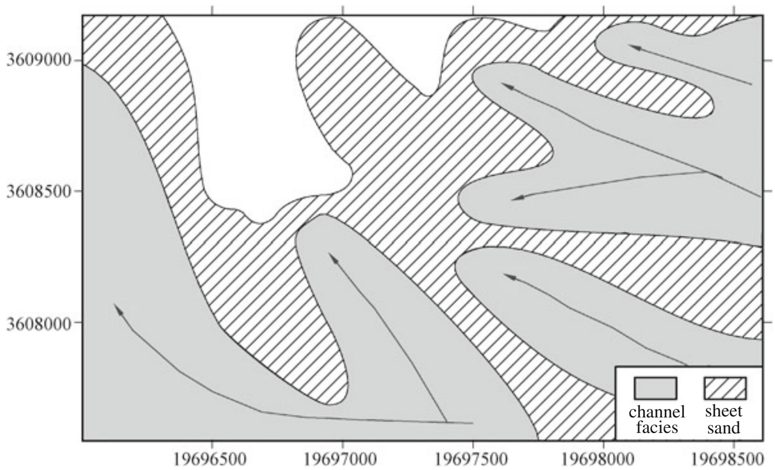


Fig. 3.17 Sedimentary micro-facies of a reservoir

3.4.3 Characteristics of Reservoir Heterogeneity

The heterogeneity of the reservoir mainly includes the heterogeneity of reservoir fluid and the heterogeneity of the reservoir. Fluid heterogeneity refers to the difference of viscosity on different planes and in different spaces. The flow resistance increases with the viscosity of crude oil, and the corresponding well spacing density should be reduced. For water drive reservoirs, there is a big difference between oil and water flow characteristics and efficiency due to the difference of oil–water mobility. In high viscosity reservoir, the water flow or water breakthrough is faster than the crude oil flow, which will lead to water fingering and produce water alone at a certain extent. According to a study of 65 reservoirs by Ivanovo, a scholar of the former Soviet Union, the number of production wells has a great influence on water cut of crude oil. The smaller the well spacing density, the lower the water cut under the condition of the same oil production of recoverable reserves. The relationship between well spacing density and water cut of crude oil is obvious when the oil viscosity is high, but its effect on low viscosity crude oil is small. For high viscosity reservoirs, dense well spacing should be adopted. If it is practical technically, a small number of wells are enough for the low viscosity reservoir, but it is not suitable for unstable (discontinuous) reservoirs.

The main factors of reservoir heterogeneity refer to the variation of reservoir permeability, especially the anisotropy, which controls the flow direction of injection fluid. As to reservoirs with good physical properties, production wells have large oil production for the single well due to its high permeability and large drainage area, and big well spacing density should be adopted appropriately in this case. According to statistics, high production can be achieved in a reservoir with a certain thickness of fractured limestone, biogenic limestone, porous limestone with good physical properties, fractured sandstone, and porous sandstone with good physical properties. The well spacing can be set as 1–3 km. For sandstone with good physical properties, the well spacing is generally set as 0.5–1.5 km; otherwise, the well spacing should generally be set as less than 1 km.

3.4.4 Development Strategies and Modes

When an industrial oil or gas field is discovered, it is very important to conduct reasonable and effective development. In answer to the national economy's requirement and the market demand for oil production, an appropriate development method and reasonable well pattern with reasonable division and combination of formations should be adopted according to the underground conditions.

The process of oilfield development must be based on development policies and strategies, which are directly related to its economic effects and technical success in the future. Correct development policies and strategies should be developed in accordance with the country's requirement of the petroleum industry and the experience from its long-term development. The development program should abide by the development policy and strategy.

In the optimization of well pattern control, the development strategies in the process of oilfield development must be taken into consideration. They include the following:

a. The rate of oil production rate.
b. The utilization and supplement of underground energy.
c. The ultimate recovery rate.
d. The years of stable production.
e. The economic effects of oilfield development.
f. The technology level.
g. The environmental impact.

The above factors tend to be dependent on and contradictory to each other, so comprehensive consideration is needed in the reasonable control of the well pattern.

Advanced production technology should be adopted in oilfield development. The development mode and well pattern deployment must also adapt to the reservoir characteristics. A series of production technologies should be determined according to different reservoirs. For the reservoir that needs artificial supplementary energy, an evaluation and study of energy supplemental mode and the conditions for it should be made. Well pattern deployment should effectively ensure the effective increase of oil production and the maximum economic recovery of an oilfield.

In order to ensure the stable growth of crude oil production in China and meet the requirement of national economy development, the stable production life is regulated for different oilfield scales macroscopically, and the specific classification is as follows:

a. For an oilfield whose recoverable reserves are more than 10^8 t, the stable production life should be more than 10 years;
b. For an oilfield whose recoverable reserves range from 5000×10^4 to 1×10^8 t, the stable production life should be in 8–10 years;
c. For an oilfield whose recoverable reserves range from 1000×10^4 to 5000×10^4 t, the stable production life should be in 6–8 years;
d. For an oilfield whose recoverable reserves range from 500×10^4 to 1000×10^4 t, the stable production life should be more than 5 years; and
e. For an oilfield whose recoverable reserves are less than 500×10^4 t, the stable production life should be more than 3 years.

Of course, for many oilfields mainly focused on economic benefits, quick return of the investment should be put in the first place and the stable production life is secondary. The purpose of investment is to recoup the investment as soon as possible, as many foreign oil companies do. At present, China's oil companies also adopt this strategy in overseas oilfield development.

Oilfield development strategy involves many development methods and various aspects in the process of development. To accelerate, the investment recovery is beneficial for improving oil production rate, which is often realized through more wells, horizontal wells, and multilateral wells with intensive injection and production. For the reservoir with intensive injection and production, the well spacing can be appropriately big. However, the well spacing should be smaller with natural energy.

3.4.5 Development Technologies and Measures

The performance of an effective and reasonable well pattern in the production process is also relevant to the working system of oil and water wells. Reservoir reconstruction and protection measures in the development process have a direct effect on the well pattern control efficiency. For example, the production pressure difference decides the supply radius, and the injection-production pressure difference controls the production capacity and the distance between oil and water wells. The production pressure systems and the corresponding well spacing should be appropriately determined according to the surface pressure and underground pressure in the process of actual production. On the one hand, formation energy should be made use of effectively; on the other hand, reasonable pressure and energy supplement should be guaranteed.

Reservoir reconstruction mainly includes physical and chemical methods such as fracturing and acid stimulation. Its main purpose is to reduce the percolating resistance and strengthen flowability or to expand reservoir supply radius, etc. For low-permeability reservoirs, if the supply radius is 100 m under certain pressure gradient and the fracture half-length is 80 m, the well spacing is usually 180 m. After fracturing, if the injection well is fractured to the same half-length of 80 m, the well spacing can increase to over 250 m with the same fracture half-length, which can greatly improve both the well pattern control and the economic benefits.

3.4.6 Geographical Environment and Economic Factors

Geographical environment and economic factors are important factors that influence the well pattern, which must be considered in the actual production. Reservoirs are buried deep under the ground and the surface conditions differ in thousands of ways, such as fields, cities, rivers, lakes, deserts, or oceans. Different surface conditions determine the differences of well patterns and the principles and requirements of its implementation.

For the oil regions with good ground conditions, such as Tuha Oilfield and Karamay Oilfield, there is no need to consider the surface conditions and the underground reservoir conditions are taken into consideration mainly. If oil regions are located in the areas of fertile lands, cities, or rivers, appropriate well sites with practicable and low cost should be chosen in the well pattern deployment.

For the oilfields located on oceans or deserts, due to the severe geographical conditions and the offshore platform and so on, huge construction and operation investments are needed, so the surface and underground characteristics of an oilfield should be considered comprehensively in the process of well pattern control so as to control more underground reserves with less investment as far as possible with efficient utilization of surface facilities, and so on. For example, Tarim Oilfield is located in the Taklamakan Desert of Xinjiang. Therefore, not only the production degree of reservoir reserves but also the return of investment should be considered in the selection of well types and well patterns due to the severe geographical conditions, deep burial, and big drilling investment.

At present, China's offshore oilfields are developing vigorously and marching to the deep sea areas. Offshore oilfields are characterized by even greater investments and risks. The offshore platform is indispensable, and one offshore platform costs hundreds of to millions of dollars. According to the law of economics, as few platforms as possible should be used, which raises higher requirements for well pattern control in offshore oilfield development.

Figure 3.18 shows a fault block in an offshore reservoir, which is composed of many small fault block reservoirs of different sizes formed due to the faulting process. For onshore reservoirs, production well groups can be deployed according to the characteristics of different oilfields. But for offshore oilfields, one platform or as few platforms as possible should be used for the well deployment to control reserves effectively.

Figure 3.19 shows several adjacent offshore oilfields. The middle oilfield is the first to have been brought into development at the initial stage, and the other oilfields are developed one after another. In order to save the investment of platform construction, the development of adjacent offshore oilfields should be taken into consideration in the initial selection and deployment of the well pattern. Only in this way can the economic and reasonable well pattern control be achieved.

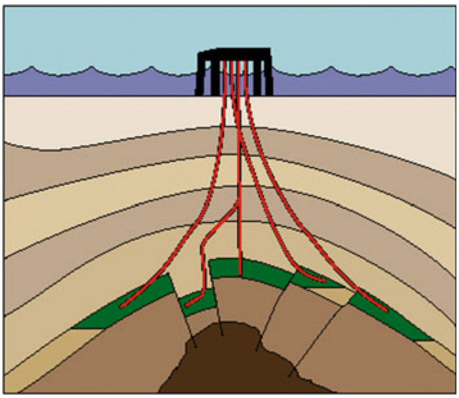


Fig. 3.18 The well pattern in an offshore reservoir

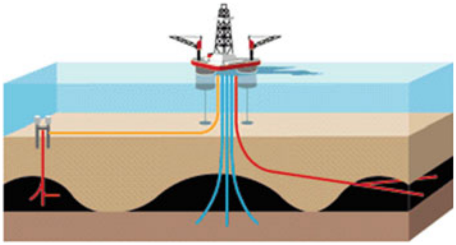


Fig. 3.19 The well pattern in an offshore reservoir

The economic factor is also an important element that must be considered in the choice of well pattern control. For any oilfields, the first consideration is economic benefits of the investment, namely the return of investment. Because the well pattern deployment is a major investment in oilfield development, well types, well spacing density, etc., should be considered together with economic factors comprehensively. Under the condition of high oil price and good economic performance, oil companies will invest more money to drill more wells because the oil production brings them economic benefits; otherwise, they would reduce drilling.

There are many other factors that influence the well pattern deployment and control, such as the buried depth. From the perspective of economics, the dense well pattern can be used in shallow reservoirs; otherwise, the sparse well pattern is adopted. This is decided by economic factors. Other factors, including geological characteristics (fractures and their directions, formation fracture pressure, and beddings) and the required oil production, also play a certain role in the well pattern deployment and control. Of them, fractures, permeability directions, and beddings have the main influence on oil recovery. Other factors also influence the oil production rate and the current economic benefits.

In addition, well spacing density is also relevant to the drilling ratio of a reservoir and the injection-production control volume in the process of oilfield development.

Chapter 4
Principles and Adjustment Methods for the Vector Well Pattern

Due to the poor adaptability of the traditional areal well pattern to the reservoir with directional characteristics and problems such as low degree of reserve recovery and unsatisfactory water flooding effect, the author has put forward a new theory of well pattern, the vector well pattern and established a new series of deployment methods of well patterns to enrich and improve the reservoir engineering theory, based on oilfield development practices and fine modern reservoir description technology.

4.1 Concept and Physical Meaning of the Vector Well Pattern

4.1.1 Concept of the Vector Well Pattern

For a long time, the well patterns designed and deployed in oilfield development are regular and common in that they all fail to consider the reservoir heterogeneity and in that the regular water injection lines of different shapes formed by injection wells inject in all directions in the reservoir. For instance, the shape of the water injection line in the four-spot well pattern is a regular diamond, while that in the seven-spot well pattern is a dual-structure regular diamond. Due to the objective existence of reservoir heterogeneity and the non-directional (isotropic) water flooding in regular well pattern, the remaining oil distribution is scattered and anisotropic, which is vectoring in mathematics. Currently, the reservoir heterogeneity is believed to be the main factor; however, the isotropic water drives also have a very important influence as a matter of fact. Therefore, in order to improve the scattered distribution of the remaining oil, there should be a new well pattern deployment concept adapted to the reservoir heterogeneity.

D. Liu and J. Sun, *The Control Theory and Application for Well Pattern Optimization of Heterogeneous Sandstone Reservoirs*, Springer Geology,
DOI 10.1007/978-3-662-53287-4_4

In order to reduce the negative impact of geological vector and reservoir heterogeneity on the development effectiveness, the concept of the vector well pattern is put forward. The vector well pattern is a comprehensive well pattern arranged and adapted on the basis of the reserve distribution, sedimentary source direction, river's direction or the principal permeability direction, fracture direction, sedimentary micro-facies, etc. The concept of the vector well pattern is mainly introduced to form clear water flooding directions, so as to achieve a better water flooding effect, which is distinguished from the traditional concept of regular well pattern. The best the vector well pattern should be determined on a detailed study of the geological vector in the oilfield development design in order to have the biggest benefit.

4.1.2 Physical Meaning of the Vector Well Pattern

The physical meaning of the vector well pattern mainly includes the following aspects:

a. The vectoring of the deployed well pattern is the same as the mathematical vectoring, referring to the direction. In a well pattern, it includes the main infiltrating fluid direction of oil flow, the direction of water flooding, and the direction of well lines.
b. It admits the directional characteristics of the reservoir, which are analyzed in detail in Chap. 2.
c. It requires the organic coupling of the well pattern deployment direction and the directional characteristics of the reservoir, for instance, the consistency of the water flooding direction with the main seepage direction yields good water flooding effects. The consistency of the oil flow direction with the main permeability direction results in higher flow efficiency and higher oil production.
d. The well pattern matches with the reservoir characteristics. For example, regarding heterogeneity, the area of weak heterogeneity within the same reservoir can be deployed with a relatively sparse well pattern and the region of strong heterogeneity can have different well densities and different well patterns, i.e., there might be diversity of well pattern deployment within the same reservoir.

Mainly illustrated here is the difference between the vector well pattern and conventional well pattern. The traditional uniform areal well pattern deployment should be improved with full understanding of the directional characteristics of the reservoir, and the well pattern should be arranged based on the traditional well pattern regarding reservoir characteristics. The aim is to optimize the control of reservoir to achieve the best water flooding effect.

4.1.3 A Case Study of the Vector Well Pattern

The key to the vector well pattern is that the reasonable well pattern is adapted to the reservoir characteristics, which is likely to be an uneven well pattern or a combination of different well patterns. The general purpose is to have the best oilfield development effect. The deployment of well patterns in actual development varies and should be considered in light of reservoir characteristics. Several instances of the vector well pattern are illustrated as follows.

4.1.4 Theoretical Basis for the Vector Well Pattern

1. Seepage characteristics of heterogeneous reservoir

The definition and types of heterogeneous reservoirs were analyzed in the previous chapters. Due to the heterogeneity of reservoirs and reservoir fluids, the movement of reservoir fluids becomes complicated. In general, theories of fluid mechanics in porous medium are mainly seepage laws based on homogeneous reservoirs, while anisotropy should be considered in the heterogeneous reservoir. As analyzed above, various types of heterogeneity can be described quantitatively

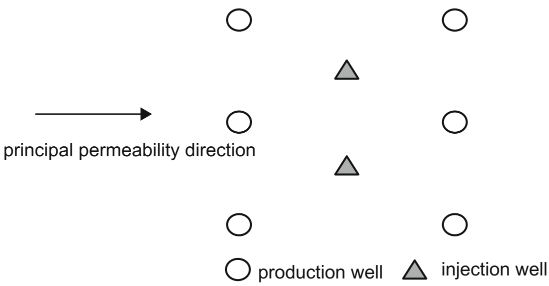


Fig. 4.1 The vector well pattern with main permeability direction

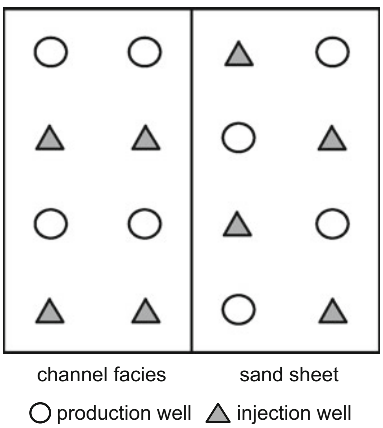


Fig. 4.2 The vector well pattern with different sedimentary micro-facies

by the anisotropy of permeability. The discussion of reservoir heterogeneity is actually the discussion of anisotropy in permeability. Introduced below is the flow mechanism of the fluid in reservoirs of permeability anisotropy. The analysis of the seepage characteristics of anisotropic reservoir can help to understand the fluid flow characteristics of such reservoirs, on which the deployment of corresponding well pattern is based. It plays an important role in improving the waterflooding effect and the degree of water flooding control (Figs. 4.1 and 4.2).

In order to simplify the problem, the underground fluid is considered to be of a single phase and equal reservoir thickness, and in the horizontal direction of the reservoir, the direction of the maximum principal permeability is perpendicular to the direction of the minimum principal permeability with an injection and production balance during the reservoir development. Under such conditions, we have developed the motion equations, the state equation and the continuity equation of the fluid, and have finally obtained the basic differential equation:

$$K_x \cdot \frac{\partial^2 p}{\partial x^2} + K_y \cdot \frac{\partial^2 p}{\partial y^2} + K_z \cdot \frac{\partial^2 p}{\partial z^2} = \varphi \mu . C_t \cdot \frac{\partial p}{\partial t} \tag{4.1}$$

where

P	is the pressure, Pa;
K_x, K_y, K_z	are the permeability values along the x-, y- and z-directions, μm^2;
μ	is the stratum oil viscosity, mPa s;
ϕ	is the effective porosity, decimal;
C_t	is the composite compressibility, Pa^{-1};
t	is the time, s

In order to get the solution, assuming

$$\begin{aligned} K_e &= \sqrt{\frac{K_x}{K_y}} \\ \bar{x} &= x\sqrt{\frac{K_e}{K_x}} \\ \bar{y} &= y\sqrt{\frac{K_e}{K_y}} \\ K_z &= 0 \end{aligned} \tag{4.2}$$

The differential equation in the new coordinate system is:

$$\frac{\partial^2 p}{\partial \bar{x}^2} + \frac{\partial^2 p}{\partial \bar{y}^2} = \frac{\varphi \mu C_t}{K_e} \frac{\partial p}{\partial t} \tag{4.3}$$

Underproduction quotas of unbounded strata, the solution of the equation is:

$$p(\bar{x},\bar{y},t) = p_i - \frac{q.\mu}{4\pi.K_e.h}\int_u^\infty \frac{e^{-u}}{u}\mathrm{d}u \tag{4.4}$$

$$u = \frac{\bar{x}^2+\bar{y}^2}{4.\eta.t},\ \eta = \frac{K_e}{\varphi\mu.C_t} \tag{4.5}$$

where

- P_i is the original formation pressure, Pa;
- q is the filtration velocity or Darcy flux, m^3/s;
- K is the permeability, μm^2;
- K_e is the average permeability, μm^2;
- η is the pilot pressure coefficient, m^2/s;
- h is the reservoir thickness, m

If multiple wells are in production at the same time, each well will have an impact on the formation pressure at any point. According to the principle for superposition, any pressure of those points in the formation can be obtained when multiple wells are in operation:

$$p(\bar{x},\bar{y},t) = p_i - \frac{\mu}{4\pi.K_e.h}\sum_{i=1}^{n}\pm q_i\int_u^\infty \frac{e^{-u}}{u}\mathrm{d}u \tag{4.6}$$

The energy expended per unit length along the $\bar{x}$-direction at any point in the formation is the pressure gradient along the $\bar{x}$-direction. Its expression is:

$$\frac{\partial p}{\partial \bar{x}} = \frac{\mu}{2\pi.K_e.h}\cdot\sum_{i=1}^{n}\pm q_i\cdot\frac{\bar{x}-\bar{x_i}}{(\bar{x}-\bar{x_i})^2-(\bar{y}-\bar{y_i})^2}\times\exp\left[-\frac{(\bar{x}-\bar{x_i})^2+(\bar{y}-\bar{y_i})^2}{4.\eta.t}\right] \tag{4.7}$$

Similarly, the pressure gradient along the $\bar{y}$-direction is obtained:

$$\frac{\partial p}{\partial \bar{y}} = \frac{\mu}{2\pi.K_e.h}\cdot\sum_{i=1}^{n}\pm q_i\cdot\frac{\bar{y}-\bar{y_i}}{(\bar{x}-\bar{x_i})^2+(\bar{y}-\bar{y_i})^2}\times\exp\left[-\frac{(\bar{x}-\bar{x_i})^2+(\bar{y}-\bar{y_i})^2}{4.\eta.t}\right] \tag{4.8}$$

As the oilfield development time is long, the exponential terms in the two formulas above can be approximated to 1.

In the study of fluid flow law, the potential function (Φ) generally represents the formation energy, while a stream function (Ψ) shows the flow velocity and flow lines. The potential function is expressed as:

$$\Phi = \frac{K}{\mu}.p \tag{4.9}$$

The relation between the potential function and the stream function is:

$$\begin{cases} \frac{\partial \Phi}{\partial x} = \frac{\partial \Psi}{\partial y} \\ \frac{\partial \Phi}{\partial y} = -\frac{\partial \Psi}{\partial x} \end{cases} \tag{4.10}$$

The function expression of the middle stream in the formation can be obtained from the above four equations. After coordinate transformation, the expression becomes:

$$\Psi = \frac{1}{2\pi.h}\sum_{i=1}^{n} \pm q_i.\mathrm{arctg}\sqrt{\frac{K_y}{K_x}} \times \frac{y - y_i}{\frac{K_y}{K_x}(x - x_i)^2 + (y - y_i)^2} \tag{4.11}$$

Where Φ, and Ψ are the potential function and the stream function, [m^2/(Pa s)] Pa.

In the seepage field, the stream function is a line linking points of a constant, namely the stream line; the required time of a fluid flowing from the injection well to the production well is called the breakthrough time of the injected fluid. According to Darcy's law, the flow rate of fluid in the x-direction can be obtained:

$$v_x = \frac{-K_x}{\mu}\frac{\partial p}{\partial x} = \frac{(x_i + \Delta x) - x_i}{\Delta t_i} \tag{4.12}$$

The time of the injected fluid flowing into the production well is:

$$t = \sum_{i=1}^{n} \Delta t_i \tag{4.13}$$

The reservoir volumetric sweep efficiency of the injected fluid flowing into the production well is:

$$E = \frac{q_i t}{Ah\phi(1 - S_{\mathrm{or}} - S_{\mathrm{wr}})} \tag{4.14}$$

where

A is the oil supply area, m^2;
E is the sweep coefficient, dimensionless;
S_{wr} is the bounded water saturation, dimensionless;
S_{or} is the remaining oil saturation, dimensionless.

To research into the best well pattern in reservoirs with heterogeneous permeability, the streamline distribution and its parameters are calculated and the difference in the fluid flowing law in reservoirs of heterogeneous permeability and homogeneous reservoirs in the five-spot and nine-spot areal well patterns are studied, as shown in Figs. 2.17, 2.18, 2.19 and 2.20 (YAN Baozhen et al.).

The streamline and its front of the five-spot well pattern in the homogeneous reservoir are shown in Fig. 2.17. It can be seen that the fluid flows evenly from the injection well, and the streamlines are evenly distributed near the injection well and the fluid appear at the same time in the four oil wells. While variations in permeability with directions exist, the ratio of the maximum horizontal permeability and the minimum horizontal permeability is 3; when the parameters of other reservoirs and fluid are the same as those of the homogeneous reservoirs, and the angle of injection well lines and the maximum principal permeability direction is 0°, 22.5°, and 45°, the streamlines and the curves of the front are shown in Fig. 2.18. As obviously seen in Fig. 2.18, the streamlines in the reservoir of permeability anisotropy are different from those in the homogeneous reservoir, and the time of the injected fluid flowing into the oil well and the sweep efficiency are all less than those in the homogeneous reservoirs. Similarly from Figs. 2.19 and 2.20, we can see that in the reservoir with anisotropic permeability, the fluid cumulates along the direction of the maximum principle permeability into the production wells, the oil wells near the direction of the maximum principle permeability are the first production wells witnessing injection effects, and the time of the injected fluid flowing into the oil well and the sweep efficiency are all less than those in the homogeneous reservoirs.

In the injection-production system of the five-spot and nine-spot well patterns, the water drive effect analysis with different angles of the water drive direction and principle permeability, and the streamlines and front curves, when the injection lines and the maximum principal permeability direction are at an angle of 0°, 22.5°, and 45°, respectively, are shown in Fig. 2.18. According to the streamline analysis and calculations, in the five-spot well pattern, the water flooding in the same direction with the maximum principal permeability has a high sweep efficiency and late water breakthrough. In the nine-spot well pattern, the linking line of the injection wells and side wells form an angle of 45° with the maximum principal permeability, the water flooding is in the same direction with the maximum principal permeability, with a high sweep efficiency and a late water breakthrough.

2. Influence of permeability direction on well pattern deployment

As permeability direction exists in a reservoir, different angles between the well pattern deployment and the permeability direction have different development efficiency in well pattern deployment. The optimal angles of different well patterns are determined by numerical simulation.

a. Well pattern arrangement

Take the inverted five-spot well pattern as an example, as shown in Fig. 4.3, the linking line of the injection wells and production wells form an angle α with the principle permeability and the different water flooding effects of different α are discussed below.

Case 1: homogeneous isotropic model with the inverted five-spot well pattern $(k_x/k_y = 1, k_x = 100 \times 10^3\ \mu\text{m}^2)$
Case 2: inverted five-spot well pattern when $k_x/k_y = 2$, $(k_x/k_y = 2, k_x = 100 \times 10^3\ \mu\text{m}^2)$.
Case 3: inverted five-spot well pattern when α = 14 and $k_x/k_y = 2, (k_x = 100 \times 10^3\ \mu\text{m}^2)$
Case 4: inverted five-spot well pattern when α = 26 and $k_x/k_y = 2, (k_x = 100 \times 10^3\ \mu\text{m}^2)$
Case 5: inverted five-spot well pattern when α = 34 and $k_x/k_y = 2, (k_x = 100 \times 10^3\ \mu\text{m}^2)$

where K_x and K_y are the principal values of permeability along the x- and y-directions, $10^{-3}\ \mu\text{m}^2$, P_1, P_2, P_3, and P_4 are the different production wells.

b. Comparison of water breakthrough time

As for the above five well patterns, the development effect of 300 days is predicted, respectively, and the difference of water breakthrough time in the production well with different well patterns is found to be obvious. The homogeneous inverted five-spot well pattern, without considering the permeability anisotropy, is arranged along the x- and y-directions with the same well spacing (250 m), so the water breakthrough times of the production wells along the x- and y-directions are the

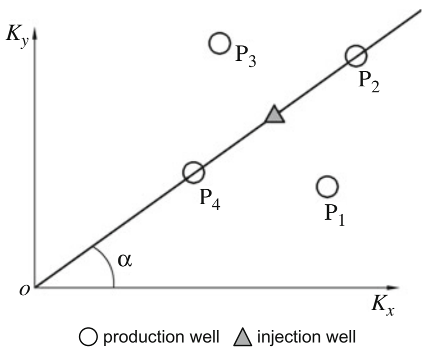


Fig. 4.3 Diagram of the inverted five-spot well pattern

same. The vector well patterns have fully considered the permeability anisotropy, and the water breakthrough times of the production wells along the x- and y-directions are nearly the same, reflecting an equilibrium displacement in the reservoir development. The water breakthrough time is specified in Table 4.1.

c. Comparison of water flooding conditions

The waterflooding conditions of the five-spot well patterns in 300 days are shown in Figs. 4.4, 4.5, 4.6, 4.7, and 4.8. As shown in the figures, after 300 days' production, the homogeneous five-spot well patterns have a water cut of 51 % in production wells along the x-direction and the y-direction. It shows that in the development, the water cuts in the production wells with the homogeneous five-spot well pattern are nearly the same, showing that the injected water has a uniform displacement in each direction.

After 300 days' production with the vector well patterns, the water cuts of the production wells along the x-direction in Case 2 and Case 3 are 47 and 49 %, respectively, and those along the y-direction are 49 and 59 %, respectively. It shows that the water cuts in the production wells along the two directions do not have a big difference, which shows that the injection has an equilibrium displacement. The water cuts of the two production wells P_2 and P_4, which are at an angle of 26° with the principal permeability direction in Case 4, are 58.37 and 48.31 %, respectively, while those of the production wells P_1 and P_3 are 50 and 50 %, respectively, which shows that in the development process, the injected water onrushes more quickly along the high permeability layer, causing non-equilibrium displacement. The water

Table 4.1 Comparison of the water breakthrough time values in the production wells with different well patterns

	P_1	P_2	P_3	P_4
Case 1	80 days	80 days	80 days	80 days
Case 2	120 days	60 days	120 days	60 days
Case 3	120 days	70 days	120 days	70 days
Case 4	120 days	70 days	120 days	80 days
Case 5	110 days	90 days	110 days	90 days

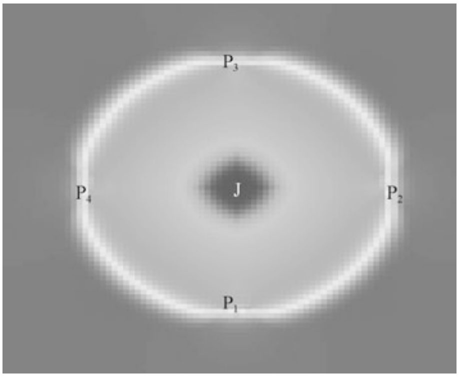


Fig. 4.4 Oil saturation after development in Case 1

Fig. 4.5 Oil saturation after development in Case 2

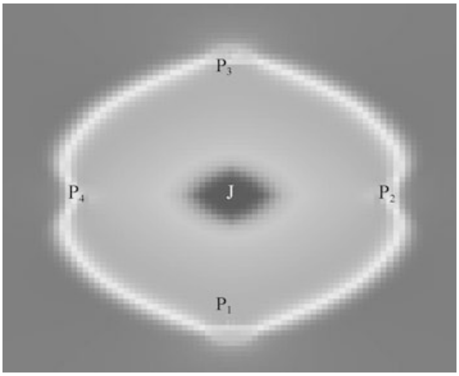


Fig. 4.6 Oil saturation after development in Case 3

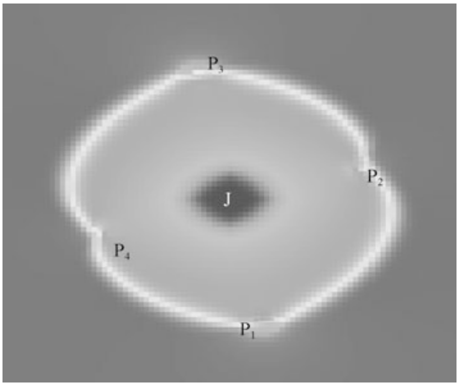
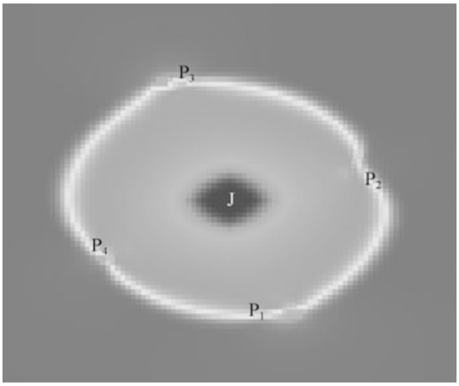


Fig. 4.7 Oil saturation after development in Case 4



cuts of two production well P_2 and P_4, which are at an angle of 34° with the principal permeability direction in Case 5, are 56.65 and 52.50 %, respectively, while those of the production wells P_1 and P_3 are 57.86 and 55.80 %, respectively, which shows in the development process, the injected water onrushes more quickly

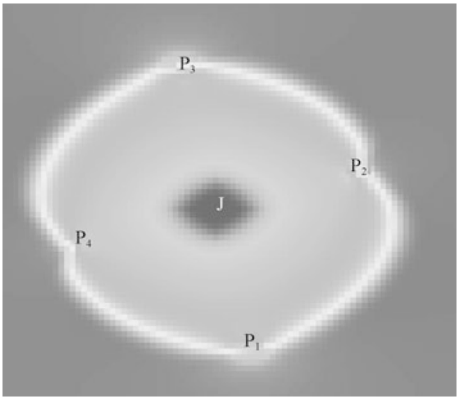


Fig. 4.8 Oil saturation after development in Case 5

Table 4.2 Comparison of water cuts in production wells with different well patterns

	Case 1	Case 2	Case 3	Case 4	Case 5
P_1 (%)	51	47	49	50	57.86
P_3 (%)	51	47	49	50	55.79
P_2 (%)	51	56	59	58.37	57.65
P_4 (%)	51	56	59	48.31	52.50

along the high permeability layer, causing non-equilibrium displacement. The comparison of water cuts in production with different well patterns is shown in Table 4.2.

d. Comparison of the degrees of reserve recovery

The degrees of reserve recovery with the five-spot well patterns are of little difference. Comparison of the recovery after 300 days' development with the five-spot well patterns regarding the production time is shown in Fig. 4.9. What can be seen in the figure is that after 300 days' production, the recovery with the homogeneous five-spot well pattern from Case 1 to Case 5 are 4.52, 4.52, 4.58, and 4.71 %, respectively. The development effects in Case 4 and Case 5 are better than the homogeneous five-spot well pattern, as shown in Fig. 4.9.

3. Study of the direction of permeability on water flooding effect

The rock core experiment is applied in studying the influence of different directions of permeability on water flooding effects. The actual oilfield development and numerical simulation results are compared in order to choose the best water flooding direction and to improve water flooding efficiency.

a. Experimental model and experimental method

The experimental model is a heterogeneous plan model with three zones of different permeability values, 50000×10^{-3}, 2000×10^{-3}, and 500×10^{-3} μm^2, respectively, in symmetrical distribution with an injection and production well spacing of 10 cm. After adjustment, the well spacing L_x along the x-direction is

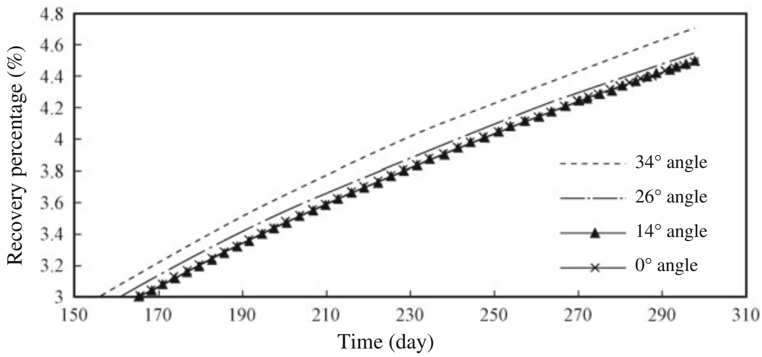


Fig. 4.9 Comparison of recovery in different plans

12 cm, while the well spacing L_y along the y-direction is 8.5 cm, which are calculated with formula (4.15).

$$L_x/L_y = \sqrt{k_x/k_y} \tag{4.15}$$

The experimental model is shown in Fig. 4.10. On the left is a conventional five-spot well pattern model, and on the right is the experimental model after well spacing adjustment.

b. Experimental results and analysis

Figure 4.11 is an early picture of the water flooding. Figure 4.11a shows that in the development with the equidistant five-spot well pattern, the injected water initially outrushes along the high permeability direction and the oil–water interface is oval shaped. Figure 4.11b shows that with the vector well pattern, in the initial injection period, the oil–water interface along the x- and y-directions advances almost at the same distance forming a round shape. The results show that the injected water

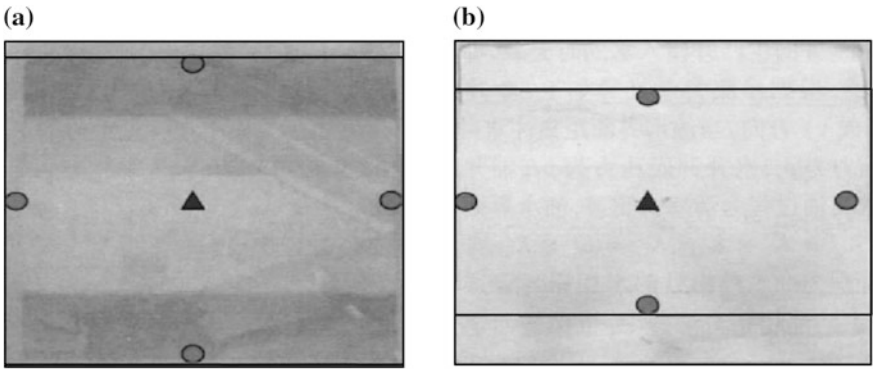


Fig. 4.10 Experimental model and well distribution

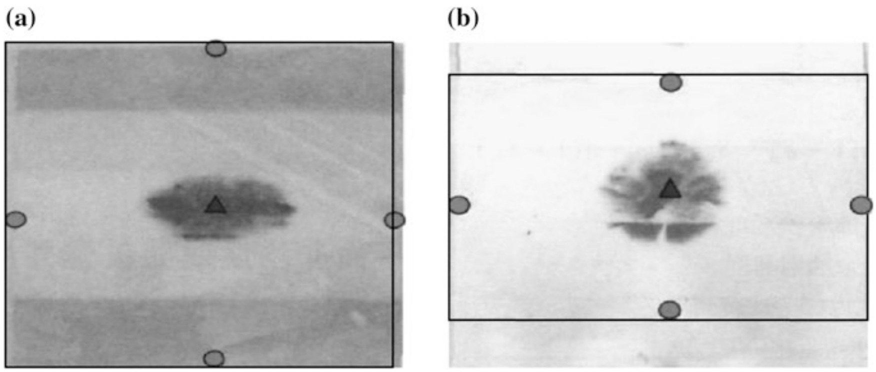


Fig. 4.11 Oil–water interface in the initial injection period with equidistant five-spot well pattern and the vector well pattern

advances evenly in all directions, inhibiting the water breakthrough in one direction only because of the plane heterogeneity. Figure 4.12 is the oil–water interface of water breakthrough in production wells. Figure 4.12a is the result of conventional five-spot well pattern development, showing that the production wells along the *x*-direction breakthrough first, and the oil–water interface in the breakthrough time of production wells along the *y*-direction is situated in the zone with the permeability of $2000 \times 10^{-3}\ \mu m^2$. Figure 4.12b clearly shows that four production wells have water breakthrough almost at the same time, which reflects that the area controlled by the well pattern has an equilibrium displacement in the reservoir, thus having reduced the influence of the low water flooding control in the horizontal heterogeneous reservoir.

Figure 4.13 is the water cut curves of the five-spot well pattern and the vector well pattern, $x1$ refers to the production well to the right of the injection well, and the counterclockwise production wells are $y1$, $x2$ and $y2$. In conventional five-spot well pattern development mode, when the comprehensive water cut of the

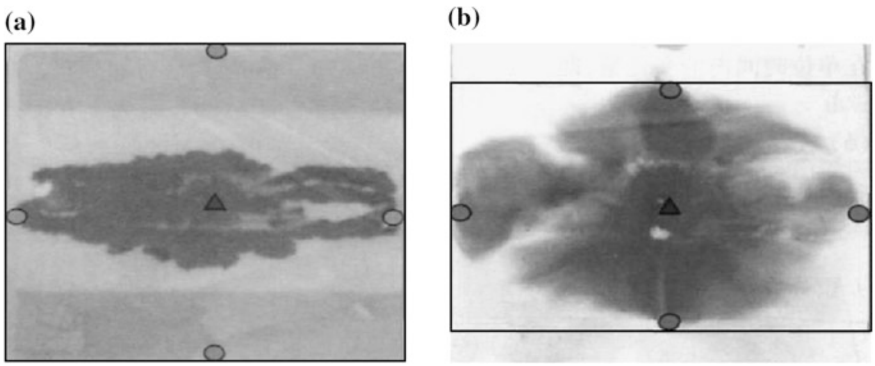


Fig. 4.12 Oil–water interface after water breakthrough with equidistant five-spot well pattern and the vector well pattern

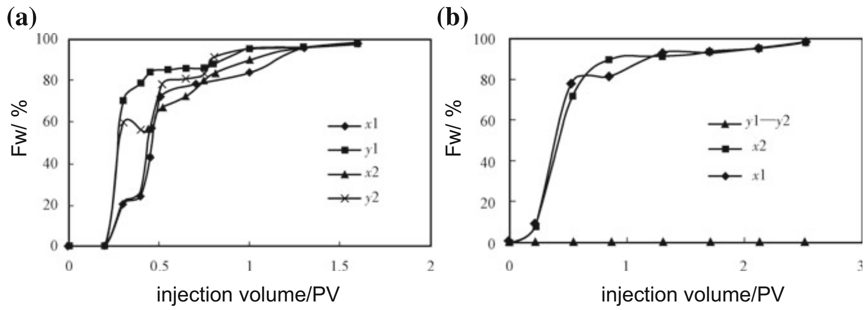


Fig. 4.13 The water cut of the conventional five-spot well pattern and the vector well pattern with the water injection volume: **a** the vector well pattern and **b** equidistance five-spot well pattern

production wells along the *y*-direction reaches 98 %, there is no water breakthrough. In the vector well pattern development mode, the water cut changing trends of the four production wells of different directions are similar. We can see that there are similarities in the water breakthrough time, the water cut rising trend, and the time to extreme water cut, which reflects the advantages of the vector well pattern development in horizontal heterogeneous reservoirs.

Table 4.3 shows the comprehensive data with the conventional five-spot well pattern and the vector well pattern. The first column shows that the water breakthrough time of the vector well pattern is later than that of the conventional five-spot well pattern, which demonstrates that the vector well pattern has delayed the water breakthrough time and extended water-free production period. The water-free recovery of the vector well pattern is two times as big as that of the conventional five-spot well pattern. Generally speaking, the bigger the water-free recovery is, the better the water flooding development of the oilfield is. When the water-free recovery of the vector well pattern is 50 %, it is in the main oil recovery stage. When the comprehensive water cut of the well group is 98 %, the ultimate recovery of the conventional five-spot well pattern is 44.1 % of the controlled reserve in well pattern, while that of the vector well pattern is 74 %. The areal sweep coefficient of the vector well pattern is 87.3 %, which is 33.9 % higher than that of the conventional five-spot well pattern, which indicates that the vector well pattern has greatly improved the sweep efficiency, so as to increase the recovery. At the end of the development, the cumulative water injection of the conventional five-spot well pattern is 2.5 PV, 96.9 % of which enters into the high permeability reservoir, causing high water cut in the production wells along the *x*-direction in a long time, which reduces the effectiveness of the water injection. The cumulative water injection of the vector well pattern is 1.6 PV, 0.9 PV less than that of the five-spot well pattern. Owing to the similar changing of water cuts and little ineffective water injection, the vector well pattern has increased the utilization rate of injected water and greatly increased the economic benefits. In conventional five-spot well pattern, the water absorbing capacity of production wells along the *x*-direction is 30.8 times as high as that along the *y*-direction, while the water

Table 4.3 Experimental data from the equidistant five-spot well pattern and the vector well pattern

Model	T breakthrough (min)	R_0 breakthrough (%)	Ipv (breakthrough) (PV)	Sweep efficiency (breakthrough) (%)	Final R_0 (%)	Final Ipv (PV)	$\frac{\sum Q_x}{\sum (Q_x + Q_y)}$	$\frac{\sum Q_x}{\sum Q_y}$
Five-spot well pattern	15	25	0.2	43.4	44.1	2.5	96.9	30.8
Vector well pattern	23	50	0.3	87.3	74.0	1.6	59.5	1.5

absorbing capacity along the x-direction in the vector well pattern is 1.5 times as high as that along the y-direction. Thus, the non-equilibrium displacement phenomenon is greatly improved.

4.1.5 The Actual Development Effect with the Vector Well Pattern

The reservoirs in the Kexia formation of the Liuzhong block are conglomerate reservoir located to the north of Kewularge fault, with an oil area of 10.3 km^2, geological reserves 2084 × 10^4 t, demarcation recovery 32 %, and recoverable reserves 657.8 × 10^4 t. It has a high crude oil viscosity and serious heterogeneity.

Reservoir characteristics:

a. Composed of foothill sedimentary conglomerate of pluvial facies
b. High shale content and great variation
c. Good reservoir connectivity with contiguous distribution of the main reservoirs $S^2{}_7$–$S^4{}_7$
d. Poor barrier characteristics with undeveloped barriers between small layers with cracks
e. High permeability with poorly graded difference of tens to hundreds of times permeability in plane and a dozen to tens of times in cross-sectional permeability
f. High crude oil viscosity with great variation in plane, the viscosity of underground crude oil is 80 mPa s, low in the East and high in the West. The surface crude oil viscosity (20 °C) in the west is up to 5000 mPa s, which is 13 times as high as that of the East. The directional characteristics of the reservoir are shown in Fig. 4.14.

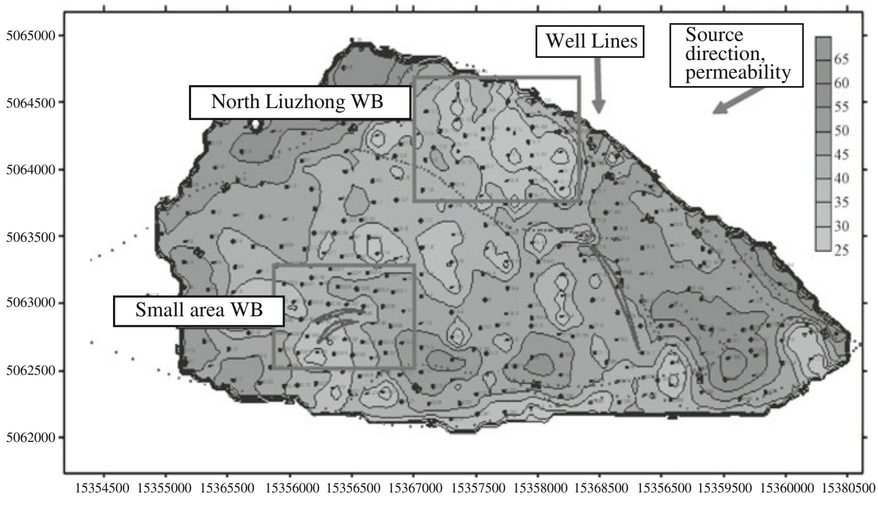


Fig. 4.14 Diagram of the water flooding effect in different well blocks

The reservoir first had industrial oil flow in Well 59 in June 1957, and in September 1974, it was put into development. In December the same year, it began an all-around water-flooding development and has been developing for 26 years. In October 2003, the whole region had 120 oil and water wells (total 294 well-times), among which there were 68 oil wells (total 189 well-times), 7 flowing wells (total 39 well-times), 61 pumping wells (total 150 well-times), and 52 injection wells (total 105 well-times). In the current block, the daily production fluid is 988 t, the daily oil production is 202 t (103 t verified), the comprehensive water cut is 79.5 %, the daily water injection is 1624 m^3, the monthly injection-production ratio is 1.55, the cumulative fluid production is 1922.70×10^4 t, the cumulative oil production is 612.06×10^4 t, the cumulative water injection is 2688.56×10^4 m^3, the cumulative deficit is -614.5×10^4 m^3, the recovery is 29.37 %, the fluid production rate is 1.73 %, the oil production rate is 0.35 %, the formation pressure is 5.41 MPa, the pressure maintenance degree is 71.37 %, and the reservoir is in the development stage of middle to high water cut.

Since its development, the reservoir has gone through three stages, namely the trial injection and production stage (Jan. 1968–Aug. 1974), the high and stable production stage (Sep. 1974–Dec. 1978) and the declining stage (Jan. 1979–the present). Because the block is composed of foothill sedimentary conglomerate of pluvial facies with serious reservoir heterogeneity, and relatively great difference in permeability and crude oil physical properties in different regions, in order to better develop the reservoir, it has been adjusted several times and different well pattern development experiments have been carried out. The reservoir is divided into seven development units, namely North Liuzhong well unit, middle Liuzhong well unit, East Liuzhong well unit, J151 North Liuzhong well unit, the large area well pattern unit, and the small area well pattern unit.

Two units of better development are evaluated. In the small area well pattern units, the five-spot water injection well pattern is used with a well spacing of 150 m; the recovery is only 34 %, and the water cut is 89 %. In North Liuzhong well unit, cross-row water flooding is used with a well spacing of 300 m; the recovery is 41 %, and the water cut is 85 %. With numerical simulation analysis, we can see that the water flooding effect of the North Liuzhong well unit is obviously better than that of the small area well pattern unit, as shown in Fig. 4.14.

In the actual oilfield development experiment, the row well pattern is used in the North Liuzhong well block. The water flooding is basically in the same direction with the sediment, source, and corresponding permeability, so that the water flooding effect is greatly improved, which conforms to the deployment principles and optimization control strategies of the vector well pattern. As for the small area well pattern unit, although it has a high well density, the water flooding effect is not ideal, due to the fact that the water flooding direction does not match the permeability direction.

Zhuang 106 block in Shengli Oilfield located on the gentle slope of the northern Chengdong uplift. It belongs to structural lithologic reservoir. Due to the control of river facies, reservoir has obvious orientation characteristic. For example, in Zhuang 106-20-x16 well group, Fig. 4.15, the production layer is 32 layers of the upper section of the Pavilion. The average permeability along the main channel direction and the vertical direction of the main channel are about 3000×10^{-3} and 2500×10^{-3} μm^2. The angle of production well row and main channel direction is about 40°. That is very close to 47.60° of the theoretical calculation value of vector well pattern design method. Thus, Zhuang 106 block has achieved good development effect. As shown in Table 4.4, the water injection wells began to be flooding in January 1999. The water-free production period (i.e., the water breakthrough time) is basically the same in the 4 production wells around. It realized a balanced displacement.

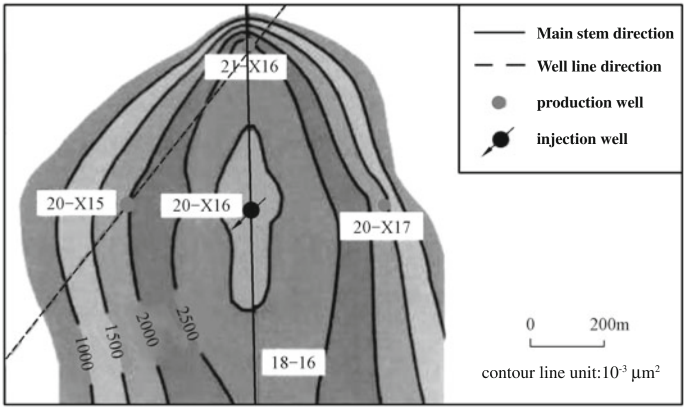


Fig. 4.15 Permeability isogram of well group Zhuang 106-20-x16

Table 4.4 Water breakthrough time of well group Zhuang 106-20-x16

Well number	Injection-production well spacing (m)	Starting date (year. month)	Breakthrough time (year. month)	Water-free production period (month)
18-16	290	1998.08	1999.07	12
21-X16	300	1998.08	1999.06	11
20-X15	250	1998.08	1999.05	10
20-X17	245	1999.05	2000.04	12

4.2 Vector Well Pattern Arrangement Principles

4.2.1 *Methods for the Vector Well Pattern Arrangement*

The vector well pattern arrangement methods are optimized methods on the basis of fine reservoir description and a clear understanding of the distribution of reserves or remaining oil. The deployment methods of the vector well pattern are as follows:

a. The water drive direction should be the same as the provenance direction, river's direction, or the principal permeability direction. For the reservoir with a clear principal permeability direction, line drive water injection is generally used. If the injection well array is perpendicular to the permeability direction, it can have a good water drive effect, but the main permeability direction and other permeability directions should be in proportion. That is, the well spacing perpendicular to the main permeability direction should be less than that parallel to the main permeability direction; this is the basic requirement of the vector well pattern deployment, which is reflected in the coupling of the reservoir and the well pattern in terms of the directional characteristics.
b. For fractured reservoir, the water drive direction should be perpendicular to the fracture direction and the injection well array should be parallel to the fracture direction; this is the basic requirements for the well pattern deployment in fractured low permeability reservoir. If the injection wells are deployed parallel to the fracture direction, the injected water will quickly go into the production wells through the fractures, resulting in sudden water flooding, and both water wells and the corresponding injection wells will be useless, costing great development effects and benefits.
c. Due to the differences of reservoir properties in different sedimentary micro-facies, different well patterns should be deployed in the development process; due to the differences in the sedimentary micro-facies, the seepage features of reservoir are quite different. To take better control of the reservoir and to develop the oilfield with investment as little as possible, rational well patterns should be deployed in accordance with the seepage features of the reservoir in different sedimentary micro-facies, including rational well spacing, injection to production well ratio, and rational recovery technology limit. Such purposeful development will lead to better effect.
d. To ensure better water drive control, the injection and production correspondence in the well deployment should be considered in terms of flow units; the reservoir fluid flow is controlled by the reservoir heterogeneity and also by the change of formation pressure. Ideal water drive effect needs good injection and production correspondence in the flow units. Generally, fluid flows do not happen between different flow units, especially not between different oil sand bodies. All deployment of well pattern must seriously consider the distribution features of flow units and oil sand bodies, taking into account as much as possible both the injection and production.

e. The determination of rational well types according to the reservoir characteristics and distribution is to be discussed in the next section.
f. The most important principle for determining the well pattern and well types is the degree of reservoir development; when the oil well is completed, all measures can only be supplementary to the improvement of the oilfield development effect. If good drainage areas can be ensured, more reserves can be controlled with a reduced workload.

4.2.2 Problems in the Vector Well Pattern Deployment

1. Well pattern deployment according to the reservoir distribution characteristics

The reservoir distribution characteristics are an important factor in the well pattern deployment. As discussed in Chap. 2, the reservoir directional characteristics are real and unchangeable, while the direction of well lines, the water drive direction, and the distribution of fracturing fractures can be manually designed and controlled in well pattern deployment. The reservoir directional characteristic, especially the principal permeability directional characteristics, should have an organic coupling with the manually controllable direction to achieve the best water flooding effects and reserve controlled.

The influencing factors in well pattern control are discussed in the fourth section of Chap. 3. In practical well pattern deployment, all factors mentioned before should be taken into consideration in light of the reservoir characteristics.

2. Well pattern deployment according to the characteristics of sedimentary micro-facies

It must be specially pointed out that there are non-seepage zones or barriers between different micro-facies, so that the injection and production correspondence would be different between different micro-facies. Similarly, high permeability zone and low permeability zone should be separately taken into consideration in the injection-production well pattern deployment. Figure 4.16 shows the plot of micro-facies of an oilfield. Flow exists in the same micro-facies when sand bodies are connected, but if there are other micro-facies between the same micro-facies, they are not connected even though the micro-facies are the same. Figure 4.17 shows the sedimentary micro-facies of a reservoir. At the edge of the micro-facies, usually an impermeable boundary exists; thus, the injection and production correspondence in the same micro-facies should be taken into consideration in the well pattern deployment.

Figure 4.18 shows the sedimentary micro-facies of a layer in a reservoir, mainly including river channels and sheet sands. Because of the great differences in the reservoir properties originated from the different micro-facies, the well spacing of the river channel should be larger than that of the sheet sand area.

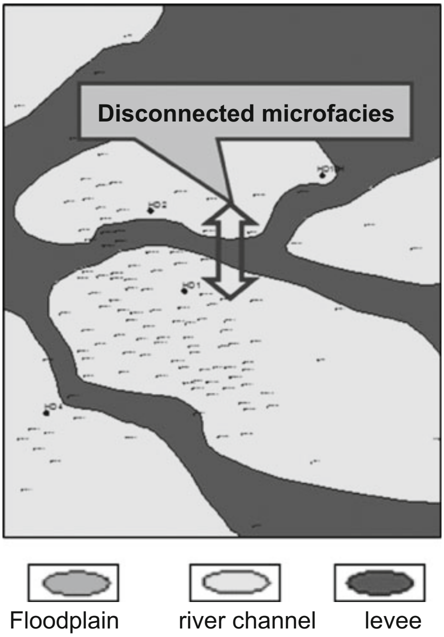


Fig. 4.16 Sand body sedimentary micro-facies of the thin sand layer 3 of an oilfield

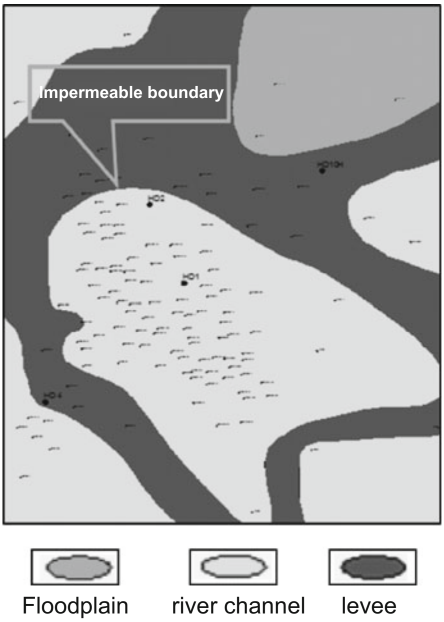


Fig. 4.17 Sand body sedimentary micro-facies of the thin sand layer 2 of an oilfield

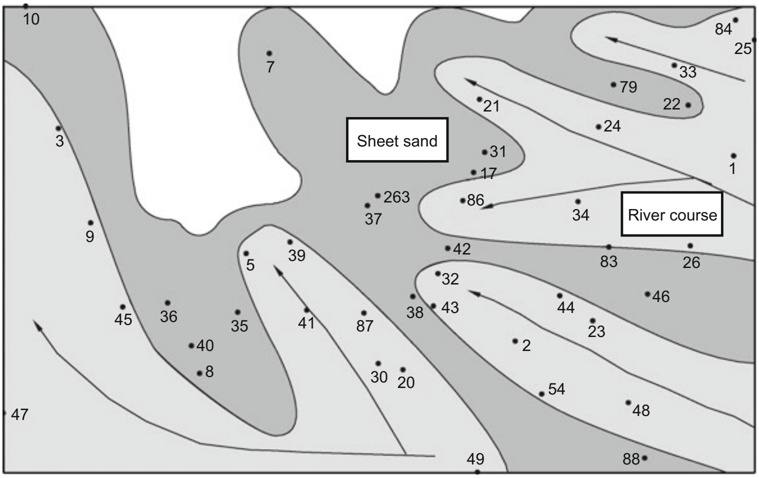


Fig. 4.18 Sand body sedimentary micro-facies of a layer in an oilfield

3. Choosing suitable well types

Modern drilling technology development makes possible a variety of well types for reservoir development from vertical wells, directional wells, and horizontal wells to multi-branch wells. Different well types have different characteristics and advantages, so in combination with the reservoir formation and characteristics and different development periods, suitable well types can be chosen with a full understanding of the reservoir, reserve distribution, and remaining oil distribution. The matching between well types and reservoir types will be discussed in the next section.

4. Well pattern deployment according to the directional characteristics of the reservoir

The directional characteristics of the reservoir, including all directions of the reservoir, are an important factor in controlling the well pattern. It has been discussed in detail in the previous chapter. Each direction controls the types and deployment of the well pattern. The principal permeability direction, faults, structural formation, edge, and bottom water burst mode should all be seriously considered.

In Fig. 4.19, only two micro-facies exit in reservoir, so different well patterns should be deployed for different micro-facies. In the underwater diversion channel micro-facies, the reservoir has directional characteristics, thus the principal permeability direction should be the same as the river direction. In the micro-facies, the deployment of well pattern should consider the consistency of the reservoir directional characteristics with the well pattern direction to achieve better water drive effect.

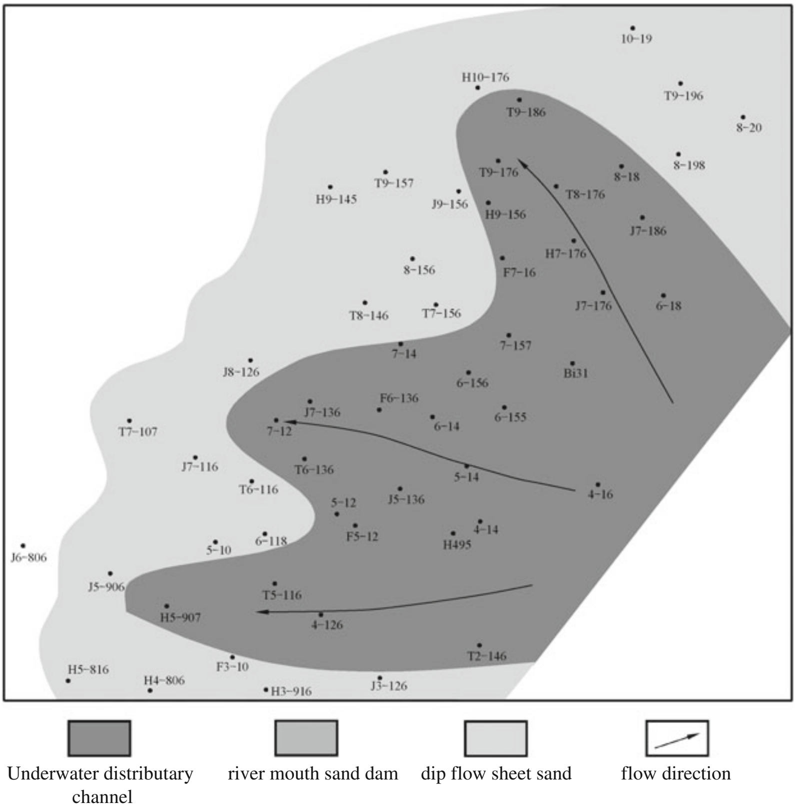


Fig. 4.19 Sand body sedimentary micro-facies in an oilfield

5. Well pattern deployment requirements in different development stages and reservoir types

Due to the fact that oilfields are deeply buried underground, human's understanding is gradually progressing. In the early development stage, there exits much uncertainty about the reservoir distribution characteristics, oil–water distribution characteristics, reservoir heterogeneity, etc.; thus, the well pattern is designed and deployed in the order of increasing difficulty. Favorable regions and better-studied regions are usually deployed first, and favorable regions are selected to drill a series of information wells to gradually study the reservoir. The development process is also a gradual understanding of the reservoir, reservoir fluid, underground oil–water distribution, etc. In different development stages, the understanding will be continuously deepened and the well pattern deployment and well type selection will be continuously optimized.

4.2.3 Choose the Right Well Types for Different Reservoirs

On the basis of full understanding of the reservoir, how to establish rational strategies on well types to better control the reserves, reduce drilling investment, and be adapted for oilfield development is an issue that must be considered in the overall optimization of development. At the same time, it must conform to the oilfield development process. According to the experience in oilfield development in China and other countries, the summarized development strategies for different reservoirs are shown in Fig. 4.20. It shows the strategies of choosing well types and rational measures for production increase in different reservoirs, which can provide excellent guide for oilfield development.

4.3 Vector Well Pattern Design

The deployment methods of the vector well pattern are optimized methods based on the fine reservoir description, under the precondition that the distribution radius of the reservoir and the distribution of the reserve or the remaining oil are clearly defined. In previous chapters, the anisotropy and expression methods of permeability are studied, but in the conventional areal well pattern of the oilfield, the permeability anisotropy is not considered. The following section will discuss how the well pattern should be deployed in heterogeneous reservoirs with anisotropic permeability. In the process of oilfield development, the vector well pattern includes many kinds of information, such as the well pattern direction and well spacing. It is not a simple mathematical vector expression.

4.3.1 Design of Well Spacing in the Vector Well Pattern

The fundamental purpose of the development of oil and gas fields is to maximize the production of underground oil and gas and improve the development benefits. The design of the well pattern and the development of the well spacing must serve this purpose. For the oilfield developed with water injection, only when the well pattern and well spacing can reach an equilibrium displacement, it can achieve a high recovery. The equilibrium placement refers to the phenomenon that the flooding agents injected from the injection wells have the same displacement degree in all directions and reach each surrounding well at the same time.

The displacement degree is expressed by the dimensionless displacement distance L_D, which is the ratio of the flooding agent's displacement distance L_d in a certain direction in a particular moment and the physical distance in this direction.

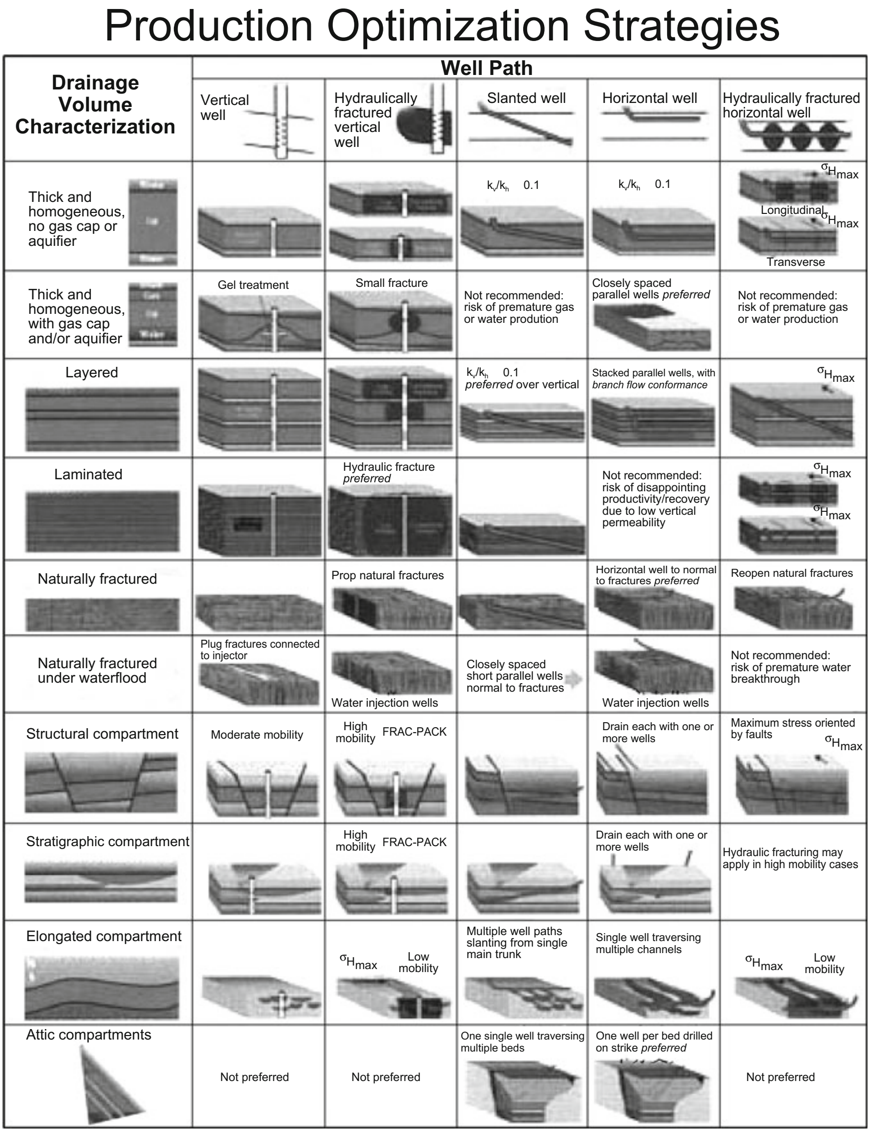


Fig. 4.20 Optimization strategies of oilfield production

$$L_D = L_d/L \tag{4.16}$$

From Fig. 4.21, it can be seen that the displacement degree on the line linking the injection and production wells is the highest, while that on the diagonal line of the area is the lowest. Therefore, it is not possible for a specific well pattern to achieve complete displacement. However, the deployment of well pattern must pursue relatively high displacement degree as much as possible. Although the well pattern in Fig. 4.21 cannot achieve complete equilibrium displacement, appropriate adjustment in well spacing can achieve that.

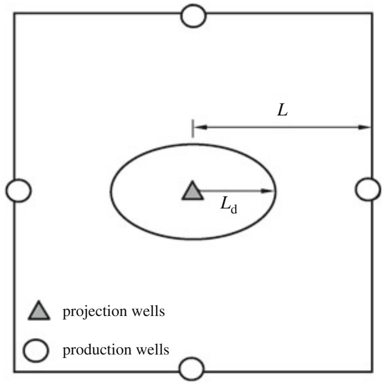


Fig. 4.21 A sketch of stratum displacement

The permeability of the planar anisotropic formation can be expressed as:

$$K = \begin{bmatrix} K_x & 0 \\ 0 & K_y \end{bmatrix} \tag{4.17}$$

where

K is the permeability tensor;
K_x, K_y are the main values of permeability along the x- and y-direction, 10^{-3} μm^2

When $K_y = K_x$, the strata are isotropic.

For isotropic formation, because the permeability is equal in every direction, the equidistance well pattern can be used to achieve an equilibrium displacement in the direction of the injection and production wells. If the distance between the injection and production wells along the x-direction is represented by d_x, while that in the y-direction is represented by d_y, the well spacing of the isotropic formation is designed in accordance with the following equation:

$$d_x = d_y \tag{4.18}$$

For anisotropic formation, the permeability is different in different directions. As a result, displacement appears first in the direction of high permeability, leading to first breakthroughs of injected fluid into the oil wells in the corresponding direction. In order to overcome the phenomenon of non-equilibrium displacement, in the direction of the relatively high permeability, well spacing must be enlarged and in the direction of relatively smaller permeability, the well spacing must be reduced. If $K_x > K_y$, the well spacing should be what is shown in Fig. 4.22, i.e., $d_x > d_y$.

There are two ways to determine the numerical relation between d_x, d_y and K_x, K_y:

1. Coordinate transformation method

According to the relevant theories of percolation mechanism, it is easy to establish the seepage differential equation of fluid in the anisotropic formation:

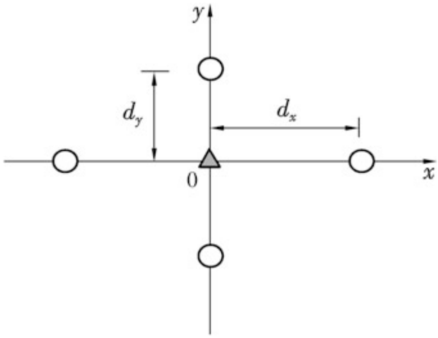


Fig. 4.22 Uneven well spacing in anisotropic formation

$$K_x \frac{\partial^2 p}{\partial x^2} + K_y \frac{\partial^2 p}{\partial y^2} = \mu \Phi \, C_t \frac{\partial p}{\partial t} \tag{4.19}$$

The symbols in the formula are the same as those in formula (4.1). It can be seen from Eq. (4.19) that the flow of underground fluid in different directions is not in equilibrium if the coordinates in Fig. 4.24 are coordinately transformed according to Eq. (4.19).

$$\begin{cases} x = X\sqrt{\frac{K_x}{K}} \\ y = Y\sqrt{\frac{K_y}{K}} \end{cases} \tag{4.20}$$

In which K is the average permeability in anisotropic formation, using the following formula to calculate:

$$K = \sqrt{K_x K_y} \tag{4.21}$$

The physical plane (x–y) in Fig. 4.22 becomes the calculating plane (x–y) in Fig. 4.23. In coordinate system (x–y), Eq. (4.19) becomes

$$\frac{\partial^2 p}{\partial X^2} + \frac{\partial^2 p}{\partial Y^2} = \frac{\mu \Phi C_t}{K} \frac{\partial p}{\partial t} \tag{4.22}$$

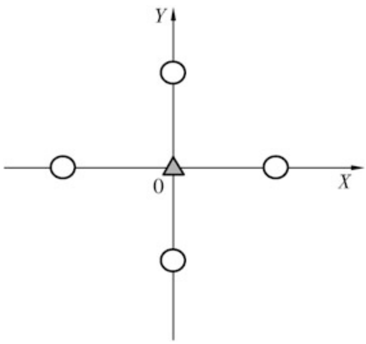


Fig. 4.23 Uniform well spacing in isotropic formation (X–Y)

From Eq. (4.22), it can be seen that after coordinate transformation of Eq. (4.20), the anisotropic (x–y) plane is transformed into an isotropic (x–y) plane. The permeability of the formation becomes the average permeability K. In the isotropic formation (x–y) plane, the equidistant well pattern should be deployed (Fig. 4.23). If in Fig. 4.23 the well spacing along the x-direction is d_X and that along the y-direction is d_Y, then the well spacing satisfies:

$$d_X = d_Y \tag{4.23}$$

Inversely transform (x–y) plane, and transform the well spacing x, d_Y of the (x–y) plane to d_X, d_Y of the (x–y) plane, substitute d_X, d_Y to Eq. (4.20).

$$\begin{cases} d_x = \sqrt{\frac{K_x}{K}} d_X \\ d_y = \sqrt{\frac{K_y}{K}} . d_Y \end{cases} \tag{4.24}$$

Therefore,

$$\frac{d_x}{d_y} = \sqrt{\frac{K_x}{K_y}} \tag{4.25}$$

Equation (4.25) shows the relation between the ratio of well spacing in different directions and the ratio of permeability in the same direction, i.e., the ratio of well spacing in different directions is equal to the square root of the ratio of permeability in the same direction.

2. Stream-tube method

When fluid flows in a straight formation, the required time t_{bt} from the inlet to the outlet is calculated by the following formula:

$$t_{bt} = \frac{\Phi \mu L^2}{K(p_1 - p_2)} \tag{4.26}$$

where

t_{bt}	is the time needed from the inlet to the outlet, ks;
Φ	is the rock porosity;
μ	is the fluid viscosity, mPa s;
L	is the distance from the inlet to the outlet;
K	is the permeability, μm^2;
P_1, P_2	are the inlet and outlet pressures, MPa

In the well pattern of the anisotropic formation as shown in Fig. 4.23, the time of breakthrough into the oil wells along the x-direction can be calculated by (4.27):

$$t_{btx} = \frac{\Phi \mu d_x^2}{K_x(p_{wi} - p_{wp})} \tag{4.27}$$

The breakthrough time into the oil wells along the *y*-direction is

$$t_{bty} = \frac{\Phi \mu d_y^2}{K_y(p_{wi} - p_{wp})} \tag{4.28}$$

where

t_{btx} is the breakthrough time along the *x*-direction, ks;
t_{bty} is the breakthrough time along the *y*-direction, ks;
d_x is the well spacing in the *x*-direction, m;
d_y is the well spacing in the *y*-direction, m;
P_{wi} is the bottom pressure in the injection well, MPa;
P_{wp} is the bottom pressure in the production well, MPa;
K_x is the permeability along the *x*-direction, μm^2;
K_y is the permeability along the *y*-direction, μm^2

The rest of the symbols are the same as before.

Only when $t_{btx} = t_{bty}$ can the displacement in the direction of the injection and production wells be in equilibrium. Therefore, the combination of (4.27) and (4.28) can lead to Eq. (4.25).

For the dual anisotropic formation, the permeability in the K_y-direction and the K_x-direction are different; at the same time, the permeability of K_x in both positive and negative directions are also different. The permeability in the positive direction K_{x+} is not equal to that in the negative direction K_{x-}, i.e., $K_{x+} \neq K_{x-}$. Therefore, in the design of injection-production well pattern, it is necessary to adjust the well spacing of the positive and negative *x*-directions to achieve equilibrium displacement. According to the previous method, theoretical formula is derived:

$$\frac{d_{x^+}}{d_{x-}} = \sqrt{\frac{K_{x^+}}{K_{x^-}}} \tag{4.29}$$

where

d_{x+} is the well spacing in the positive direction, m;
d_{x-} is the well spacing in the negative direction, m;
K_{x+} is the permeability in the positive direction, μm^2;
K_{x-} is the permeability in the negative direction, μm^2

If $d_{x+} > d_{x-}$, the adjusted well spacing is shown in Fig. 4.24. The situation in the y-direction is similar to that in the *x*-direction.

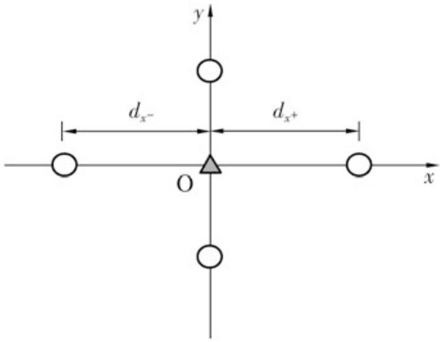


Fig. 4.24 Dual anisotropic formation of uneven well spacing

4.3.2 Direction Design of the Vector Well Pattern

From the design of well spacing above, it can be seen that to realize the equilibrium displacement of fluid in an anisotropic reservoir, the ratio of different directional well spacing in the vector well pattern should be equal to the square root of the ratio of permeability in the corresponding direction. The direction of the vector well pattern is the angle θ of the direction of the injection water (oil production) well line and the maximum permeability direction.

$$\theta = \arctan \frac{d_y}{d_x} \tag{4.30}$$

From previous studies:

$$\theta = \arctan \sqrt{\frac{K_y}{K_x}} \tag{4.31}$$

Equation (4.31) shows that the direction of the vector well pattern in the anisotropic formation is no longer special angles of 0°, 22.5°, and 45°. The angles should be selected in accordance with the specific conditions of permeability in the anisotropic formation. It can be seen from Fig. 4.25 that the direction of the vector well pattern and the ratio of the main values of the formation permeability (K_y/K_x) are non-linear. When $K_y/K_x = 1.0$, the reservoir is an isotropic and the well pattern direction is 45°; When $K_y/K_x = 0.5$, the well pattern direction is 35°; When $K_y/K_x = 0.25$, the well pattern direction is about 26°. In this view, the rational well pattern direction should be adjusted according to the anisotropy of the reservoir.

It can be seen from the design methods of the vector well pattern above that the overall conductivity in all directions of anisotropic reservoirs is equivalent to that of the isotropic reservoir with the permeability of $K = \sqrt{K_x K_y}$. The development effect of the permeability anisotropic reservoir can be replaced by the equivalent development effect of the isotropic reservoir, while the well pattern design (areal

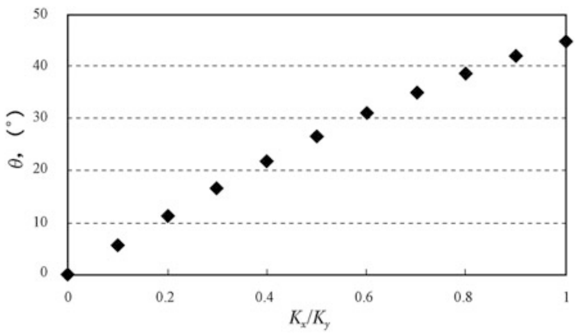


Fig. 4.25 Relation curve reflecting the ratio of the direction of the vector well pattern to the main value of formation permeability

well pattern) and its development effect analysis techniques have already been mature. If the well spacing of the equivalent isotropic reservoir is a' and the well array spacing is d', then the well spacing and row spacing of the anisotropic reservoir well pattern are respectively designed as a and d. In other words, if the well spacing and row spacing of the well pattern in anisotropic reservoirs are designed as a and d, the development effect of this well pattern is equivalent to that of the isotropic reservoir when the well spacing is a' and the row spacing is d'. The relation between a', d' and a, d, is determined by (4.32).

$$\begin{cases} a = a'\sqrt{\frac{K_x}{K}} \\ d = d'\sqrt{\frac{K_y}{K}} \\ K = \sqrt{K_x K_y} \end{cases} \tag{4.32}$$

According to the above deployment methods of the vector well pattern, the relation between the well pattern in anisotropic reservoir and the equivalent isotropic reservoir is made, as shown in Figs. 4.26 and 4.27.

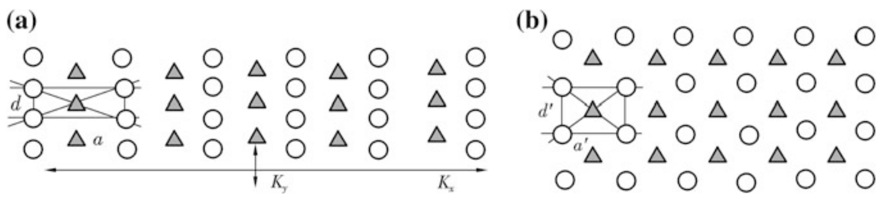


Fig. 4.26 Variation of five-spot well pattern in anisotropic reservoir and equivalent isotropic reservoir

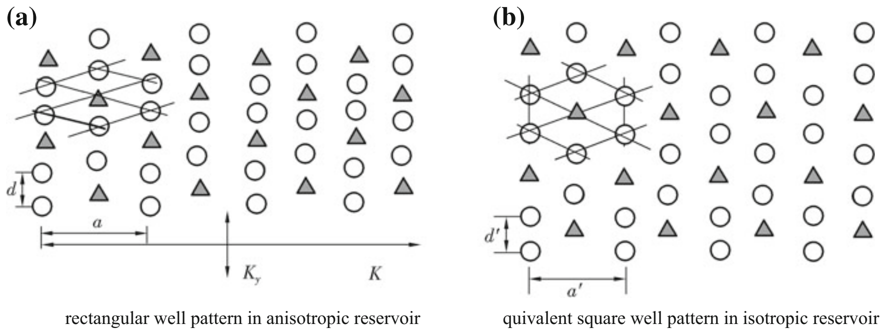


Fig. 4.27 Variation of seven-spot well pattern in anisotropic reservoir and equivalent. **a** Rectangular well pattern in anisotropic reservoir. **b** Equivalent square well pattern in isotropic reservoir

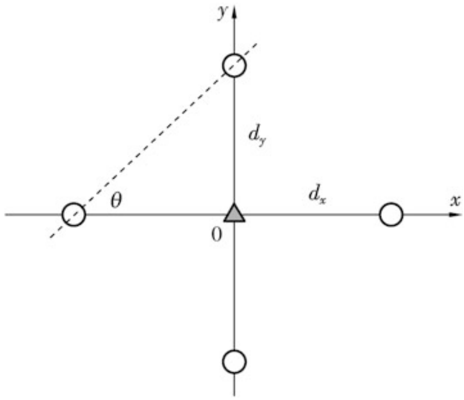
4.3.3 Case Studies of the Vector Well Pattern Design

In a heterogeneous reservoir, the permeability in the *x*-direction is 9 times as high as that in the *y*-direction. According to the previous research, the equivalent homogeneous model of the heterogeneous model can be established. Because the well pattern design in the homogeneous model has already been mature, the rational well pattern for the homogeneous reservoir is established first, and then the well pattern is converted to a heterogeneous reservoir according to the theory of the vector well pattern. In this way, the rational well pattern in heterogeneous reservoir can be obtained.

1. Well pattern design of equivalent homogeneous reservoir

The permeability in the x, y is $K_x = 900 \times 10^{-3}$ and $K_y = 900 \times 10^{-3}$ μm^2, respectively, for heterogeneous reservoir. The heterogeneous reservoir can be changed into the equivalent homogeneous reservoir with the permeability in the x- and y-directions of $K = \sqrt{K_x K_y} = \sqrt{900 \times 100} = 300$ (10^{-3} μm^2). With the five-spot well pattern and based on the rational well pattern deployment methods for homogeneous reservoir, the homogeneous model has a well spacing density of 12.5 well/km^2, the corresponding well spacing $d_x = d_y = 282$ m, and the row direction $\theta = 45°$, as shown in Fig. 4.28.

Fig. 4.28 Five-spot pattern design of the equivalent homogeneous reservoir



2. Well pattern design of the heterogeneous reservoir

According to the transformation relation of the well pattern in the homogeneous reservoir and that in the heterogeneous reservoir, we can get

$$\frac{d_y}{d_x} = \sqrt{\frac{K_y}{K_x}} = \sqrt{\frac{100}{900}} = \frac{1}{3}$$

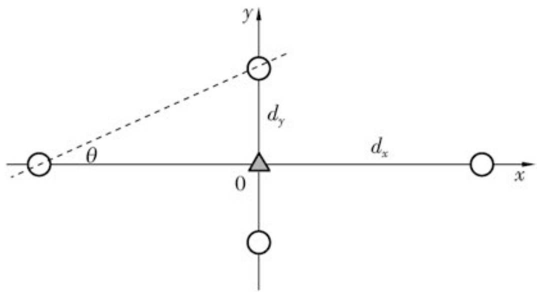
If d_y = 282 m, then

d_x = 846 m, $\theta = \arctan\frac{d_y}{d_x} = \arctan\sqrt{\frac{K_y}{K_x}} = \arctan(0.33) = 18^{\circ}$

$$\theta = \arctan\frac{d_y}{d_x} = \arctan\sqrt{\frac{K_y}{K_x}} = \arctan(0.33) = 18^{\circ}$$

The well pattern is shown in Fig. 4.29.

Fig. 4.29 Five-spot well pattern design of the heterogeneous reservoir



4.4 Adjustment Methods Based on the Vector Well Pattern

Previously discussed are the general deployment strategies of the vector well pattern, which are mainly used in the well pattern design in oilfield early development stage and in the adjustment of existent well patterns relying on the definition and deployment requirements of the vector well pattern. The vectoring adjustment of well patterns include such comprehensive measures as transformation of well pattern, drilling infill wells, closing (stopping) wells and converting production wells to water wells, aiming at adapting the well pattern to the main permeability direction, the sedimentary source direction, the river's direction, the reservoir distribution, the fracture direction, and the sedimentary micro-facies. The premise of such adjustments is the fine description of the reservoir and a clear understanding of the distribution of the remaining oil. At present, some of the adjustment theories are still in the research and exploration stage. Research institutes in Shengli Oilfield and Zhongyuan Oilfield as well as higher learning institutions like Yangtze University and China Petroleum University have worked on this field and presented some research findings, which are specified as follows.

4.4.1 Adjustment Strategies for the Permeability Anisotropic Reservoir

At present, well pattern is generally deployed in consideration that the oilfield is composed of homogeneous strata, without considering the permeability anisotropy. However, the existence of the permeability anisotropy, i.e., vectoring, has a certain negative impact on the development effectiveness of the reservoir, especially in the reservoir of fluvial facies. The major problems include the advanced flow of the injected fluid along the direction of relatively high permeability, causing difference in the water breakthrough time in production wells in different directions, resulting in non-equilibrium waterflooding and displacement, thus affecting the development effects. In order to reduce the negative effects of the permeability anisotropy, the following methods are put forward to promote the equilibrium displacement of fluid in the reservoir.

1. Wells pacing control

In general, two production wells deployed in different directions of a water injection well have different permeability values in different directions. To achieve equilibrium displacement, based on the percolation theory, the two production wells should meet the following formula:

$$\frac{l_x^2 \phi_x}{k_x dp_x} = \frac{l_y^2 \phi_y}{k_y dp_y} \tag{4.33}$$

where

l_x, l_y are the respective distances of the injection well to the x-direction and the y-direction, m;
φ_x, φ_y are the porosities along the x-direction and y-direction, decimal;
k_x, k_y are the permeability of the injection well to the x-direction and y-direction, μm^2;
p_x, p_y are the pressure differences of the injection well to the x-direction and the y-direction, MPa

Rearranging formula (4.33), the model of well spacing control can be established.

$$\frac{l_x}{l_y} = \sqrt{\frac{k_x dp_x \varphi_y}{k_y dp_y \varphi_x}} \tag{4.34}$$

2. Injection-production differential pressure control

Rearranging formula (4.34), we can get the model:

$$\frac{dp_x}{dp_y} = \frac{l_x^2 \varphi_x k_y}{l_y^2 \varphi_y k_x} \tag{4.35}$$

For drilled production wells, the well spacing has been fixed and the physical parameters of the reservoir are also very difficult to change (reservoir reconstruction measures can only partially transform the reservoir properties in most cases); therefore, it is very effective and convenient to control the injection and production differential pressure to achieve equilibrium displacement; meanwhile, it provides theoretical basis for later oilfield development stage of “stable oil production and controlled water cut.”

3. Design of well spacing in different directions according to the vector anisotropy of permeability

The directionality of rock permeability depends on the orientation of sands and the orientation and filling mode of the sands’ structural particles. The permeability in the direction parallel to the sands’ transportation increases obviously; in the alluvial sandstones, the direction of the maximum permeability is consistent with that of the river channel axis, while in the upper shore surface sandstones and beach sandstones, the direction of the maximum permeability is parallel to the direction of the tide. The direction of maximum permeability in well test analysis and rock core measurement is the same as that of the ancient water flow; thus, the rock permeability shows a vector characteristic, which is called vector. ZHOU Yongqi from Shengli Oilfield has established a calculation model of vector permeability based on the equivalent displacement principle. The calculation formula is:

$$K_n = K_x \cos^2 \alpha + K_y \sin^2 \alpha \tag{4.36}$$

The model can be used to calculate the vector of the corresponding rock permeability (K_n) in any direction n (the azimuth angle is α) in the plane. When the permeability in different directions is known, the well spacing design can be carried out according to the following equation:

$$\frac{d_x}{d_y} = \sqrt{\frac{k_x}{k_y}} \tag{4.37}$$

where

k_x, k_y is the permeability in the x-direction and y-direction, μm^2;
d_x, d_y is the well spacing in the x-direction and y-direction, m

4.4.2 Adjustment Strategies in Terms of Reservoir Characteristics

1. Waterflooding in the thick oil layer and production in the thin oil layer

The distribution of sand body in continental sedimentary reservoir is not stable, with uneven thickness. With heterogeneous single pipes and plane models, researchers in Daqing Oilfield reached the conclusion that when the quantity of injection wells and production wells are the same; if the injection wells are deployed in the thin oil layer while the oil wells are in the thick oil layer, the early production of oil wells is high, but it becomes low in the period of middle and high water cut. On the contrary, if the oil wells and injection wells are exchanged, the oil wells still have a relatively high production in the period of middle to high water cut. The experimental results show that the water flooding in thick oil area increases the water flooding volume by 7.9–12.5 % and the recovery by 12.8 %.

2. Flooding in the high permeability zone and producing oil in the low one

Zhongyuan Oilfield, in light of plane heterogeneity of the reservoir, adopted the measure of waterflooding in the river channel's high permeability zone and producing in the shoreside low permeability zone, and achieved good development effects in the development practice. Strata 6-8 of Hu-7-South-S3 had an experiment of flooding in the channel and producing oil in the edge area in 1994. In the river channel, there were six closed oil wells of high water cut and two converted injection wells, and the well spacing became larger from 150 to 220 m. However, the daily oil production of strata 6-8 increased from 46 to 64 t, the comprehensive water cut declined from 87.6 to 85.3 %, the average producing liquid level rose from 1263 to 1148 m underground, and the storage capacity rate increased from 39.5 to 52.9 %. Of the 10 edge oil wells, seven were effective, with an efficiency rate of 70 %.

3. Waterflooding in the edge (outer region) and producing oil in the inside

For the small oil-bearing reservoir which is cut and enclosed by multiple faults or shielded at three sides by faults while leaving one side open, due to the poor natural energy, it needs supplementary energy and it is suitable to flood in the edge and produce oil in the inside, which can avoid the loss of partial crude oil flowing to the oil-free area at the edge caused by water injection in the center. Similarly, as shown in Fig. 4.30, the production wells are deployed in the angle between the faults, and the injection wells are deployed at the opening of the faults, transmitting all the water injection energy to the oil well with the shields formed by the faults, achieving good development effects. The block Qing-23 in Qingzuji Oilfield has such a typical example. In a single small block with a reserve of merely 60,000 t, the current oil production is 28,000 t, with a recovery of 46.7 %.

4. Flooding with high well spacing density at the top but low at the edge

The fault tendency of the ridge type reservoir is contrary to the formation tendency. Near the top of the main fault, there are many thick and concentrated oil-bearing layers. According to the statistics, the top of fault block in general has 60 % of the reserves, while its oil-bearing area has only 20–30 %. The well pattern of "waterflooding with high well spacing density at the top but low at the edge" has been proven to benefit the effective control of reserves and to significantly improve the development effect.

5. Well spacing adjustment according to the paleocurrent direction

The directions of paleosource and paleocurrent result in the orientation arrangement of the reservoir rock particles. Along the particle orientation, the seepage resistance is the least. Similarly in the river channel, the permeability along the paleocurrent direction is higher than that in the upstream flow direction, which should be considered in well pattern deployment. As shown in Fig. 4.31, with the same injection and production well spacing, water injection and injection pressure, the injected water from water well B flows earlier into well C, while the injected water from well A is very difficult to reach the oil well. It shows that the injection effect in the direction of well A is poor. This mainly lies in the significant increase of water

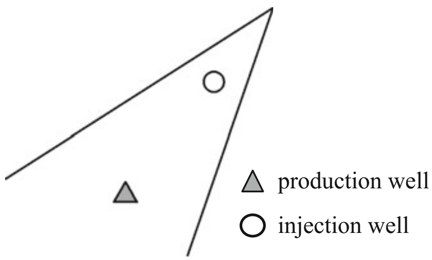


Fig. 4.30 Water injection in the edge or outer region

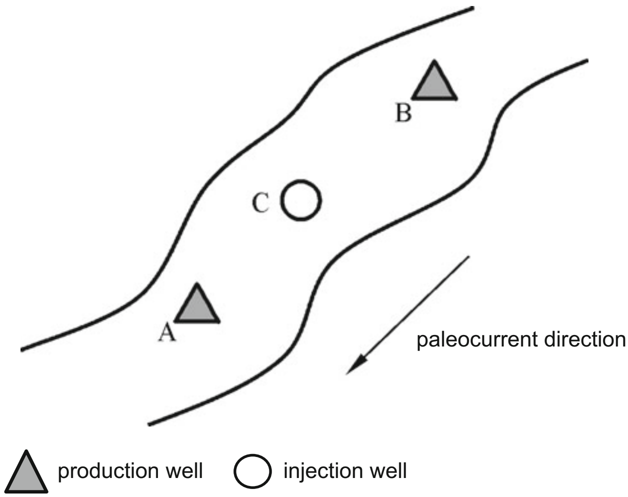


Fig. 4.31 Diagram of injection in the paleocurrent direction

phase permeability after the water breakthrough in the oil well, which has limited the oil seepage in the direction of well A. Therefore, we should be especially cautious in the injection well and production well management, trying as much as possible to enable the waterlines in different directions to reach the oil well simultaneously.

6. Vertical to fracture in displacement direction

Whether natural or artificial, fractures have great influence on the waterflooding effect. If the oil and water wells are deployed along the fracture direction, the injected water will rapidly leak along the fractures, resulting in sudden water flooding in oil wells and poor oil displacement effect. However, if the oil wells with water leakage along the fractures are converted into injection wells, the injection along the fractures will have better water flooding effect. The experiment on the fractures and water flooding effects in North Wen-13 shows that the efficiency of water flooding is the highest when the direction of the fracture and the water injection direction are at an angle of 90°, and the lowest when the direction of the fracture is parallel to the water injection direction. The experiment also shows that the injection well spacing in general should be larger than the oil well spacing and larger than the row distance between the injection wells and oil wells.

4.4.3 Adjustment Strategies in Terms of Sedimentary Micro-facies Characteristics

Generally speaking, the oilfield in the late development stage has been studied with fine reservoir description and the sedimentary micro-facies in the main strata have been clearly recognized. Areas of different micro-facies have different permeability

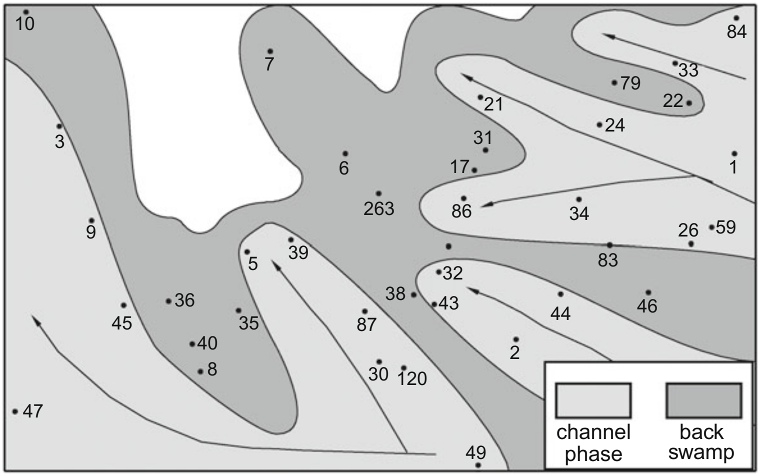


Fig. 4.32 Sedimentary micro-facies of a reservoir

values, which impose obvious directionality on the fluvial facies deposition, especially on the channel permeability. Moreover, due to the great difference in permeability and poor connectivity between different micro-facies, the well pattern adjustment should be considered in the same micro-facies. In other words, we should consider the corresponding injection and production relation in the same micro-facies and flow unit, and the injection displacement direction. During the well pattern adjustment, the characteristics of reservoir orientation should be fully recognized to realize the organic coupling between the adjusted well pattern and the reservoir orientation. Figure 4.32 describes the sedimentary micro-facies of a reservoir, which include the channel micro-facies and the front sheet sand micro-facies. In the adjustment process, the injection and production correspondence should be studied in combination with performance analysis, to adjust as much as possible the injector-producer connection in the same micro-facies and to form an optimal well pattern.

Chapter 5
Well Pattern Models for Different Reservoir Characteristics

Reservoir development practice shows that in addition to the reservoir characteristics and fluid properties, reservoir development effect also depends on the modes of well pattern deployment, i.e., the geometry between injection and production wells. The actual reservoir is heterogeneous. The permeability along certain direction is higher than that along other directions. Development effect will be seriously affected if the well pattern is designed according to the assumption of uniform permeability, because the oil wells arranged in the maximum principal direction of the permeability will be flooded ahead of others and the oil wells arranged in other directions will hardly be affected by waterflood effect. Because of the different reservoir physical properties in different sedimentary micro-facies, corresponding well spacing density needs to be determined according to the different micro-facies. In this chapter, a comparison analysis of different well patterns is made by means of advanced numerical simulation software of Eclipse. The results can provide theoretical basis for designing the optimal well pattern in heterogeneous oil reservoirs.

In this chapter, the geological models for the numerical simulation and well pattern optimization are selected from appropriate areas according to the requirement in actual geological models unless otherwise stated. Porosity, permeability, and saturation of the reservoir belong to middle-high permeability sandstone reservoir. The average permeability is 420×10^{-3} μm^2, the average porosity is 0.24, the oil saturation is 0.70, and the porosity is about 25 %.

D. Liu and J. Sun, *The Control Theory and Application for Well Pattern Optimization of Heterogeneous Sandstone Reservoirs*, Springer Geology,
DOI 10.1007/978-3-662-53287-4_5

5.1 Well Pattern Optimization for Channel Deposit Sedimentary Micro-facies

In this section, the research is focused on the deployment mode of well pattern optimization in the reservoir mainly with river channel sedimentary micro-facies. In general, channel deposit is the best part in terms of reservoir physical properties and connectivity. The reservoir has obvious directivity. Its maximum principal permeability direction is along the direction of the river channel, which is decided by the deposition process. In the development process, this kind of reservoir characteristics needs to be made full use of it to select the reasonable well pattern mode, the well type, and the waterflooding direction for the optimal waterflooding effect. A high production is likely to be obtained in such areas. However, serious heterogeneity causes disconnection between the interlayer and sand bodies, which affects the development effect.

5.1.1 Development Effects of Different Well Patterns

Different modes of well pattern deployment are designed according to the characteristics of a reservoir. According to the principle for well pattern optimization control and the requirements of the vector well pattern deployment, two major well arrangement schemes, the five-spot pattern and the line well pattern, are designed. In fact, these two kinds of well pattern are similar. The five-spot pattern, in essence, is a kind of staggered line well pattern. The two well patterns meet the requirements of well pattern controlling theory. On this basis, the well pattern controlling parameters are optimized, including injection-production ratio and well spacing. For this purpose, the optimal well spacing and injection-production ratio of the two well patterns are calculated and analyzed with the same oil recovery factor of 2 %.

1. The five-spot well pattern
   The five-spot well pattern is the most common pattern used in the process of actual oilfield development. It is not only a form of uniform areal well pattern with strong injection and production method, but also a line flooding pattern with homogeneous interlaced distribution of oil wells and injection wells. Therefore, five-spot well pattern has much room for adjustment.

   (a) Set the injection-production ratio and determine the optimal well spacing
   The injection-production ratio set as 1:1, four well patterns with various well spacings, i.e., 200, 250, 300, and 350 m, are simulated and calculated. The recovery degree in unit time taken as the selection criteria, the results are as follows in Fig. 5.1.
   Figure 5.1 shows that the optimal well spacing for the five-spot well pattern is d = 300 m.

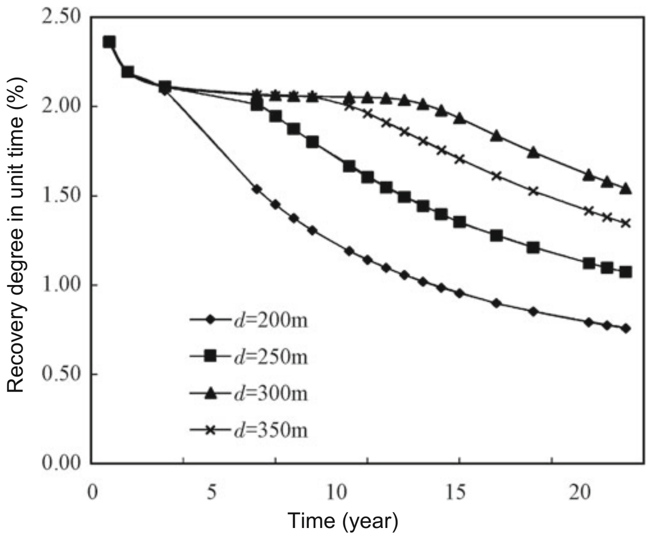


Fig. 5.1 Relation curve of the recovery degree in unit time (1)

(b) Set the well spacing and determine the optimal injection-production ratio
The optimal well spacing set as $d = 300$ m, six cases with various injection-production ratios, i.e., 0.7, 0.8, 0.85, 0.9, 1.0, and 1.1, are simulated and calculated. The results are as follows in Table 5.1.
The results show that the scheme with the injection-production ratio as 0.8 is superior to the other schemes. Therefore, for the five-spot well pattern, the optimal well spacing is 300 m and the optimal injection-production ratio is set as 0.8.

2. Line water flooding pattern

   (a) Set the injection-production ratio and determine the optimal well spacing

Table 5.1 Simulation results under different injection-production ratio conditions (1)

Scheme	Injection-production ratio	Present recovery degree (%)	Water cut 85 %		
			Recovery degree (%)	Produced water per ton produced oil (m^3)	Injected water per ton produced oil (m^3)
1	0.70	18.26	40.02	2.08	3.07
2	0.80	18.47	40.26	2.20	3.20
3	0.85	18.41	40.21	2.31	3.32
4	0.90	18.36	40.13	2.35	3.35
5	1.00	18.09	40.06	2.35	3.35
6	1.10	18.01	40.01	2.35	3.35

The injection-production ratio set as 1:1, five well patterns with various well spacings, i.e., 200, 250, 300, 350, and 400 m, are simulated and calculated. The recovery degree in unit time taken as the selection criteria, the results are as follows in Fig. 5.2.

The results show that the optimal well spacing for the line well pattern is 350 m.

(b) Set the well spacing and determine the optimal injection-production ratio

The optimal well spacing set as 350 m, six well schemes with various injection-production ratios, i.e., 0.75, 0.8, 0.9, 0.95, 1.0, and 1.5, are simulated and calculated. The results are as follows in Table 5.2.

The results show that the scheme with the injection-production ratio as 0.9 is superior to the other schemes. Therefore, for the line well pattern, the optimal well spacing is 350 m and the optimal injection-production ratio is set as 0.9.

3. Comparative study of development effects between different well patterns
A comparison is made between the five-spot well pattern and the line well pattern under the condition of the optimal well spacing and optimal injection-production ratio, respectively. The simulation results are shown in Table 5.3.

The results show that the development effects of line well pattern are obviously better than the five-spot areal well pattern. Therefore, a conclusion can be made that for the channel main sedimentary micro-facies, the optimal water flooding mode is line well pattern with a well spacing d = 350 m and injection-production ratio I = 0.9.

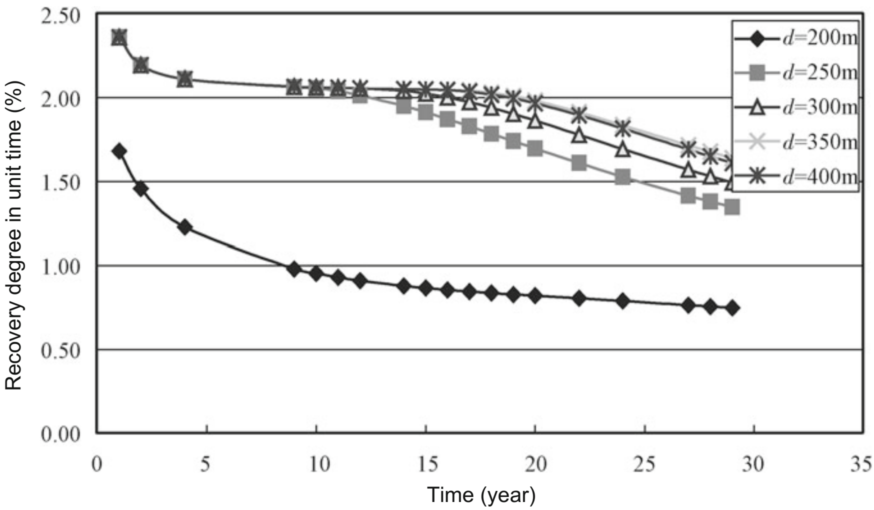


Fig. 5.2 Relation curve of the recovery degree in unit time (2)

Table 5.2 Different injection-production ratio values through analog computation (2)

Scheme	Injection-production ratio	Present recovery degree (%)	Water cut 80 %		
			Recovery degree (%)	Produced water per ton produced oil (m^3)	Injected water per ton produced oil (m^3)
1	0.75	18.09	54.11	1.92	2.85
2	0.80	18.11	54.03	1.99	3.06
3	0.90	18.59	53.27	1.90	2.87
4	0.95	18.41	53.20	1.93	2.91
5	1.00	18.12	53.12	1.95	2.96
6	1.50	18.01	53.08	1.97	2.99

Table 5.3 Comparative study of development effects between the five-spot well pattern and the line well pattern

Water injection mode	Well spacing	Injection-production ratio	Present recovery degree (%)	Water cut 85 %		
				Recovery degree (%)	Produced water per ton produced oil (m^3)	Injected water per ton produced oil (m^3)
Five-spot well pattern	300	0.80	18.47	40.26	2.20	3.20
Line well pattern	350	0.90	18.59	53.27	1.90	2.87

5.1.2 *Water Flooding Direction Optimization*

On the basis of the above study, the influence degree of different angles between water flooding direction and principal permeability on development effects is studied to determine the optimal vector well pattern for the line well pattern with the principal permeability direction taken into consideration.

Two schemes are designed as shown in Fig. 5.3. They are both line well patterns with a well spacing $d = 350$ m and an injection-production ratio $I = 0.9$. In the model, the maximum permeability direction is parallel to the x-axis. The simulation results are shown in Figs. 5.4 and 5.5.

Scheme 1: The injection well row is vertical to the maximum permeability direction.
Scheme 2: The angle between the injection well row and the maximum permeability direction is 45°.

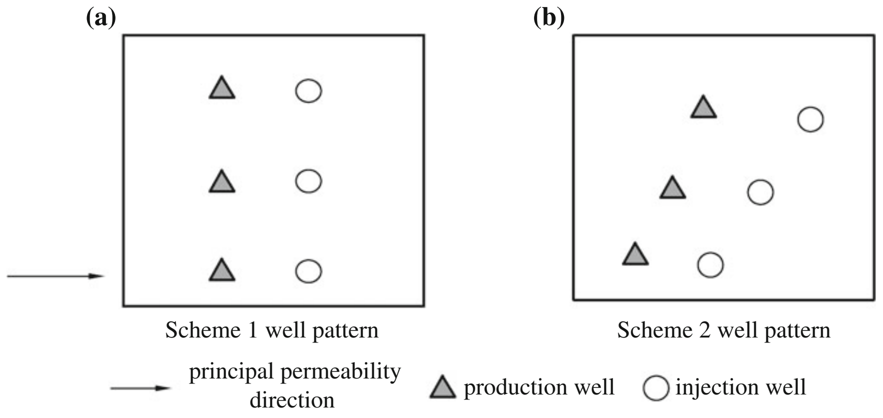


Fig. 5.3 Schemes of well pattern deployment 1, Scheme 1 well pattern, Scheme 2 well pattern

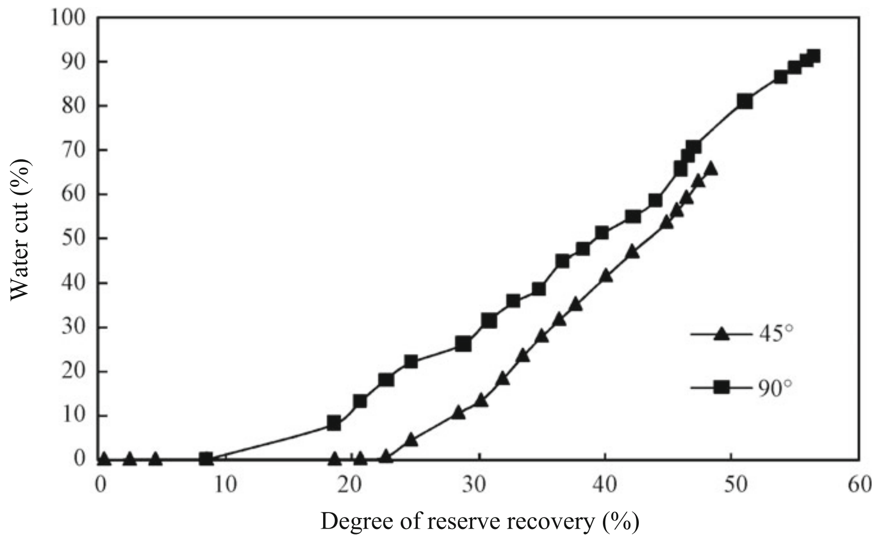


Fig. 5.4 Relation curve of recovery degree and water cut

Obviously, the primary permeability direction has a great influence on the development effect for river sedimentary micro-facies waterflooding with line well pattern.

When the angle between the injection well row and the maximum permeability direction is 90°, that is, when the main permeability direction is consistent with the waterline movement direction, the water breakthrough of production wells occurs earlier, the daily oil production is higher, and the development effect is much better than the case with an angle of 45° between the injection well row and the maximum permeability direction.

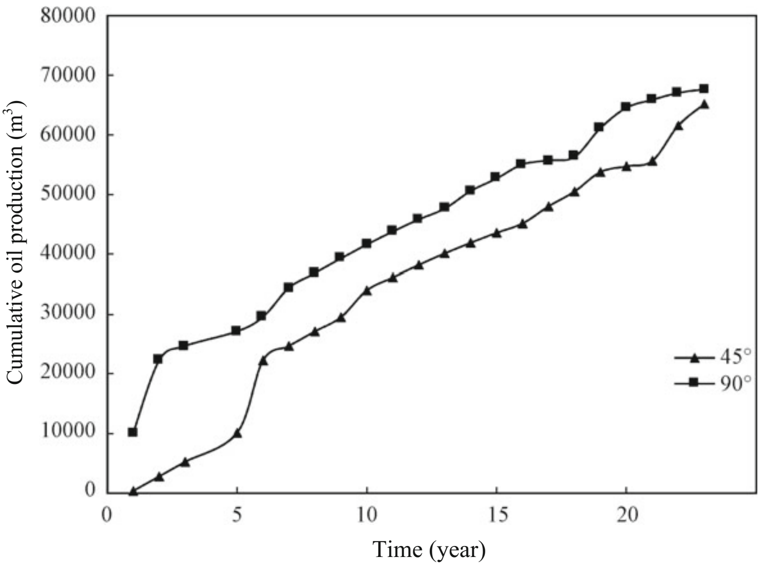


Fig. 5.5 Cumulative oil production curve

These suggest that the physical properties of sand bodies in channel sedimentary micro-facies are very good. Influenced by the source direction, the permeability distribution is regular, and the waterflooding effect is the best when the main permeability direction is consistent with the water advance direction.

5.2 Well Pattern Optimization for Sheet Sand Sedimentary Micro-facies

The oil group H_3VI in an oilfield in Henan is chosen as the prototype reservoir. The reservoir depth is 1893 m, the average effective thickness is 8.6 m, the oil–water interface depth is 1990 m, the initial formation pressure is 19.1 MPa, the gas–oil ratio is 32 m^3/t, the oil volume factor is 1.15, and the oil and water density is 0.8508×10^3 and 1.000×10^3 kg/m^3, respectively. The length and width of the actual geological model are 750 and 10 m, respectively. The Cartesian coordinates are adopted. The plane grids of model are 15 × 15 grids, and there is one layer in the longitudinal direction. The average permeability is 38×10^{-3} μm^2, the average porosity is 0.18, and the oil saturation is 0.60.

5.2.1 Development Effects of Different Well Patterns

Based on theory of well pattern optimization control, three schemes of well pattern deployment are designed according to the characteristics of sheet sand sedimentary micro-facies and well pattern deployment research. Under the condition of the same production rate of 2 %, the optimal well spacing and injection-production ratio of the inverted nine-spot flooding pattern, the five-spot flooding pattern, and the line flooding pattern are calculated and analyzed to optimize the well pattern.

1. The inverted nine-spot well pattern

(a) Set the injection-production ratio and determine the optimal well spacing

The injection-production ratio set as 1:1, four well patterns with various well spacings, i.e., 150, 200, 250, and 300 m, are simulated and calculated. The recovery degree in unit time taken as the selection criteria, the results are as follows in Fig. 5.6.

Figure 5.6 shows that the optimal well spacing for the nine-spot well pattern is $d = 250$ m.

(b) Set the well spacing and determine the optimal injection-production ratio

The optimal well spacing set as $d = 250$ m, five schemes with various injection-production ratios, i.e., 0.7, 0.75, 0.8, 0.85, and 0.9, are simulated and calculated. The results are as follows in Table 5.4.

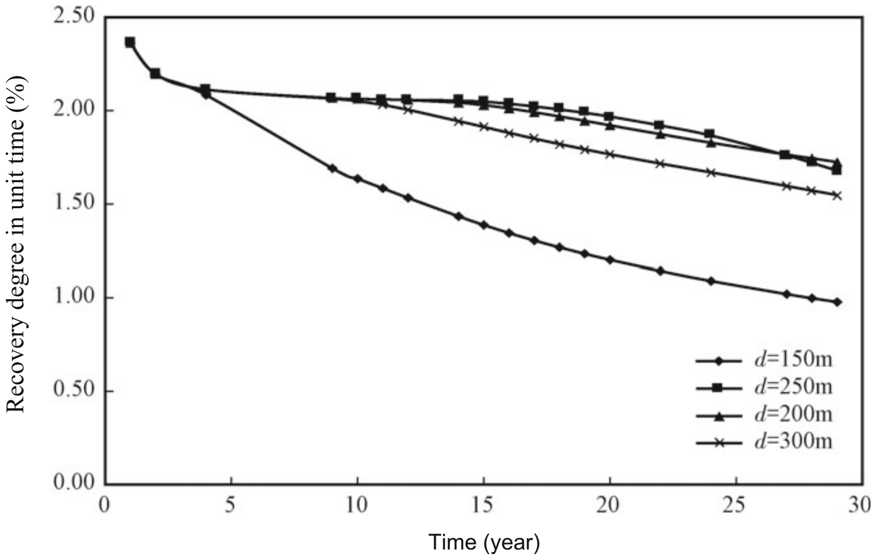


Fig. 5.6 Relation curve of the recovery degree in unit time (3)

Table 5.4 Simulation results under different injection-production ratio conditions (3)

Scheme	Injection-production ratio	Present recovery degree (%)	Water cut 85 %		
			Recovery degree (%)	Produced water per ton produced oil (m^3)	Injected water per ton produced oil (m^3)
1	0.70	18.65	54.50	1.93	2.36
2	0.75	18.64	54.92	1.89	2.56
3	0.80	18.69	54.97	1.64	2.40
4	0.85	18.70	54.81	1.98	2.65
5	0.90	18.92	54.03	1.86	2.51

The results show that the scheme with the injection-production ratio as 0.8 is superior to the other schemes. Therefore, for the nine-spot well pattern, the optimal well spacing is 250 m and the optimal injection-production ratio is set as 0.8.

2. The five-spot well pattern

(a) Well spacing optimization fixing injection-production ratio

The injection-production ratio set as 1:1, four well patterns with various well spacings, i.e., 150, 200, 250, and 300 m, are simulated and calculated. The recovery degree in unit time taken as selection criteria, the results are as follows in Fig. 5.7.

Figure 5.7 shows that the optimal well spacing for the five-spot well pattern is d = 250 m.

(b) Injection-production ratio optimization fixing well spacing

The optimal well spacing set as 250 m, six well schemes with various injection-production ratios, i.e., 0.8, 0.85, 0.9, 0.95, 1.0, and 1.5, are simulated and calculated. The results are as follows in Table 5.5.

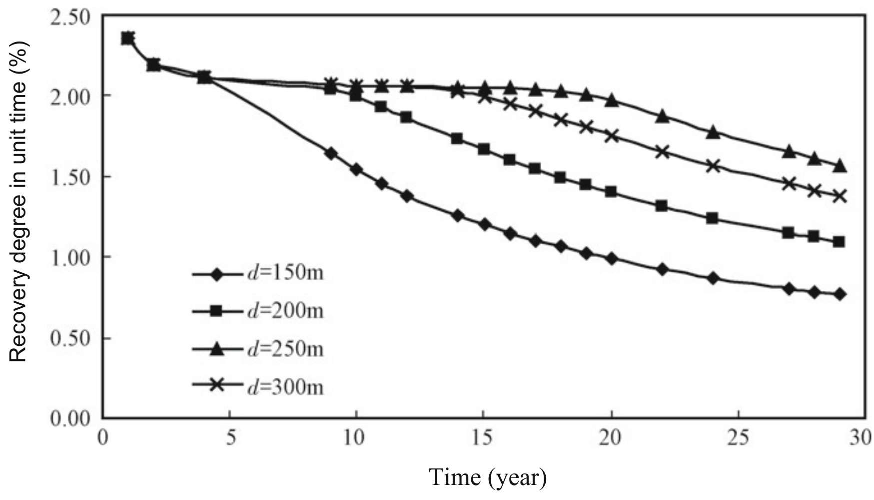


Fig. 5.7 Relation curve of the recovery degree in unit time (4)

Table 5.5 Simulation results under different injection-production ratio conditions (4)

Scheme	Injection-production ratio	Present recovery degree (%)	Water cut 85 %		
			Recovery degree (%)	Produced water per ton produced oil (m^3)	Injected water per ton produced oil (m^3)
1	0.80	18.42	45.67	2.07	3.23
2	0.85	18.59	45.71	2.10	3.54
3	0.90	18.59	45.73	2.12	3.13
4	0.95	18.45	45.71	2.14	3.61
5	1.00	18.36	45.67	2.16	3.68
6	1.50	17.85	45.35	2.18	3.72

The results show that the scheme with the injection-production ratio as 0.9 is superior to the other schemes. Therefore, for the five-spot well pattern, the optimal well spacing is 250 m and the optimal injection-production ratio is set as 0.9.

3. Line water flooding pattern

(a) Well spacing optimization fixing injection-production ratio

The injection-production ratio set as 1:1, five well patterns with various well spacings, i.e., 150, 200, 250, 300, and 350 m, are simulated and calculated. The recovery degree in unit time taken as selection criteria, the results are as follows in Fig. 5.8.

The results show that the optimal well spacing for the line well pattern is 300 m.

(b) Injection-production ratio optimization fixing well spacing

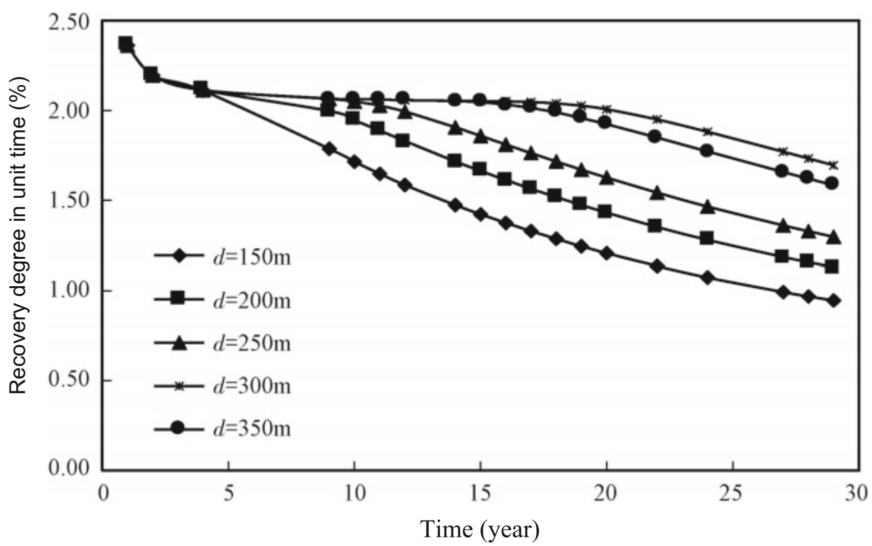


Fig. 5.8 Relation curve of the recovery degree in unit time (5)

Table 5.6 Simulation results under different injection-production ratio conditions (5)

Scheme	Injection-production ratio	Present recovery degree (%)	Water cut 85 %		
			Recovery degree (%)	Produced water per ton produced oil (m^3)	Injected water per ton produced oil (m^3)
1	0.75	17.85	48.91	2.24	3.22
2	0.80	17.91	48.73	2.35	3.35
3	0.85	18.59	48.05	2.14	3.11
4	0.90	18.61	48.16	2.41	3.48
5	1.00	18.61	47.25	2.31	3.41
6	1.50	18.40	47.31	3.01	3.62

The optimal well spacing set as 350 m, six well schemes with various injection-production ratios, i.e., 0.75, 0.8, 0.85, 0.9, 1.0, and 1.5, are simulated and calculated. The results are as follows in Table 5.6.

The results show that the scheme with the injection-production ratio as 0.85 is superior to the other schemes. Therefore, for the line well pattern, the optimal well spacing is 300 m and the optimal injection-production ratio is set as 0.85.

5.2.2 *Comparative Study on the Development Effects of Different Well Patterns*

A comparison is made between the five-spot well pattern, the inverted nine-spot well pattern, and the line well pattern under the condition of the optimal well spacing and optimal injection-production ratio, respectively. The simulation results are shown in Table 5.7.

Table 5.7 A comparative study of the development effects between five-spot well pattern, inverted nine-spot well pattern and line well pattern

Water injection mode	Well spacing	Injection-production ratio	Present recovery degree (%)	Water cut 85 %		
				Recovery degree (%)	Produced water per ton produced oil (m^3)	Injected water per ton produced oil (m^3)
Inverted nine-spot well pattern	250	0.8	18.69	54.97	1.64	2.40
Five-spot well pattern	250	0.9	18.59	45.73	2.12	3.13
Line well pattern	300	0.85	18.59	48.05	2.14	3.11

The results show that the development effect of inverted nine-spot well pattern is obviously better than the five-spot areal well pattern and the line well pattern. Therefore, a conclusion can be made that for the sheet sand sedimentary micro-facies, the optimal water flooding mode is inverted nine-spot well pattern with a well spacing $d = 250$ m and an injection-production ratio $I = 0.8$.

5.2.3 Vector Well Pattern Optimization

On the basis of the above study, the influence degree of different angles between water flooding direction and principal permeability on development effects is studied to determine the optimal vector well pattern for the inverted nine-spot well pattern when the principal permeability direction is taken into consideration.

Three schemes are designed as shown in Fig. 5.9. They are all inverted nine-spot well patterns with a well spacing $d = 250$ m and an injection-production ratio $I = 0.8$. In the model, the maximum permeability direction is parallel to the x-axis. The simulation results are shown in Fig. 5.10.

Scheme 1: The line connecting the injection well and the edge well is parallel to the maximum permeability direction.
Scheme 2: The angle between the line connecting the injection well and the edge well, and the maximum permeability direction is 22.5°.
Scheme 3: The angle between the line connecting the injection well and the edge well, and the maximum permeability direction is 45°.

Obviously, the primary permeability direction has a great influence on the development effect for sheet sand sedimentary micro-facies with inverted nine-spot well pattern.

When the angle between the line connecting the injection well and the edge well is 45°, the development effects are significantly better than those when the angles are 0° or 22.5°. When the angle between the line connecting the injection well and the edge well is 0°, water breakthrough in production wells occurs earlier than that in those with angles of 45° and 22.5°. However, when the water cut is over 35 %, the water cut in the case of the angle of 22.5° increases fastest, and the

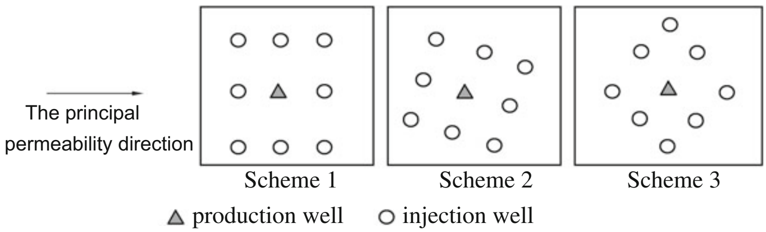


Fig. 5.9 Schemes of well pattern deployment 2

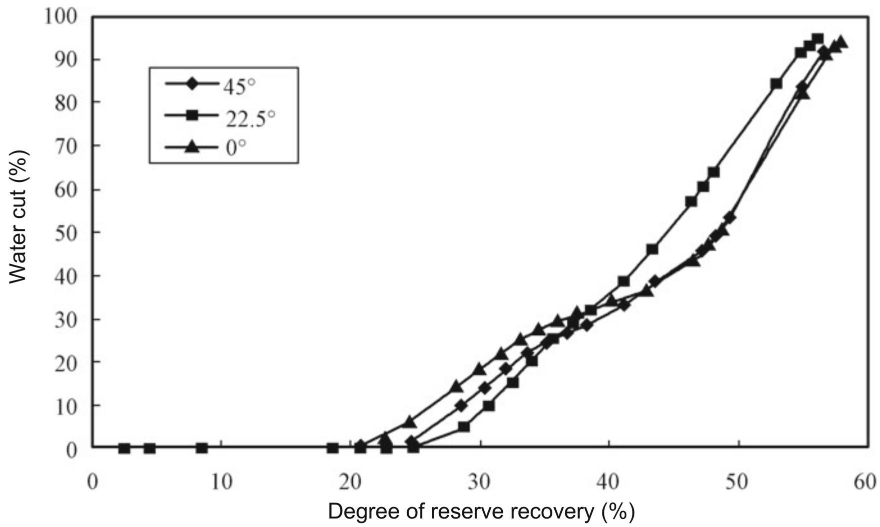


Fig. 5.10 Relation curve of recovery degree and water cut

corresponding recovery degree is the smallest under the condition of the same water cut. The curve of 45° angle almost coincides with the curve of 0° angle.

These suggest that the influence of the source direction on the sheet sand sedimentary micro-facies is smaller than the river channel sedimentary micro-facies, and the permeability distribution regularity is weak.

This also helps to prove YAN Baozhen's opinion that in the inverted nine-spot well pattern, the water flooding effects are different when the angles between the water flooding direction and the main permeability direction are different, and that the sweep efficiency is big and injectant breakthrough occurs late when the angle between the line connecting the injection well and the edge well is 45°.

5.3 Development Effects Analysis on Well Patterns of Different Micro-facies Combinations

The oil group H_3IV3^1 of a oilfield is chosen for the analysis. Its depth is 2200 m, the effective thickness is 10 m, the OWC depth is 2250 m, the original formation pressure is 23.84 MPa, the gas–oil ratio is 21.3 m^3/t, the oil volume factor is 1.56, and the density of oil and water is 0.847×10^3 and 1.0×10^3 kg/m^3, respectively. The length, width, and height of the geologic model are 1100, 1100, and 10 m, respectively. The Cartesian coordinates are used to build the model, which is divided into 22×22 subgrids horizontally with only one layer vertically. Horizontally, this model is made up of two different sedimentary micro-facies. The left part of the model, which consists of *X* range from 1 to 11 subgrids and Y range from 1 to 22 subgrids, falls into the scope of river channel sedimentary micro-facies, with an average permeability of 400×10^{-3} μm^2, an average porosity of 0.23, and an oil saturation of 0.75. The right part of the model falls into the scope of sheet sand sedimentary micro-facies, with an average permeability of 40×10^{-3} μm^2, an average porosity of 0.18, and an oil saturation of 0.64. The primary permeability direction and source direction are parallel to the y-direction.

5.3.1 *Influence of Different Well Patterns on the Development Effect*

Based on the geologic model mentioned above, three schemes (Fig. 5.11), i.e., the five-spot well pattern, the line well pattern, and the combination of the two well patterns are designed according to the requirements of the research.

The left area is characterized by the river sedimentary micro-facies and the right area is the sheet sand sedimentary micro-facies. The development effects of the three well patterns are studied under the same oil recovery factor of 3 %.

Through numerical simulation, the development indexes of different schemes are shown in Tables 5.8, 5.9, 5.10 and Fig. 5.12.

The following analyses can be made based on Fig. 5.12. The development effect of Scheme 1 of the horizontally uniform five-spot well pattern is the worst. Its cumulative oil production is 1.44×10^4 m^3 lower than that of Scheme 3. In Scheme 1, the angle between the primary permeability direction in river sedimentary micro-facies and injection well array is 45°. The development indexes show that Scheme 2 performs better than Scheme 1, because the primary permeability direction of the river channel sedimentary micro-facies is perpendicular to the injection well array, which will enhance the water drive performance. Different well patterns are designed for different sedimentary micro-facies in Scheme 3. The line injection well pattern is used for the river sedimentary micro-facies, and the five-spot well pattern is used for the sheet sand sedimentary micro-facies.

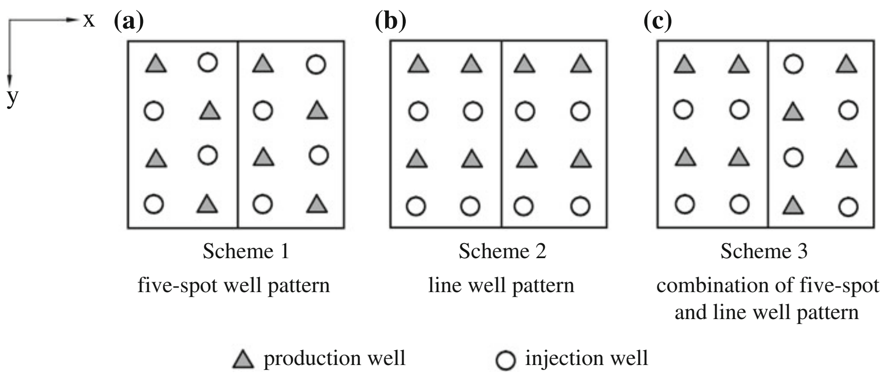


Fig. 5.11 Well patterns for different combinations of sedimentary micro-facies (1)

Table 5.8 Scheme 1: Development index prediction for 20 years

Index time	Cumulative oil production (m^3)	Recovery degree (%)	Formation pressure (MPa)	Water cut (%)
0	0	0	23.96	0
2	75823.11	6.60	23.48	0.12
4	151670.50	13.19	23.18	0.09
6	227488.70	19.79	22.86	0.25
8	301845.50	26.25	22.48	6.30
10	368317.30	32.04	22.07	14.00
12	429386.00	37.35	21.47	27.00
14	475624.30	41.37	21.04	45.00
16	516357.30	44.91	20.81	65.00
18	537405.40	46.74	20.75	79.00
20	553565.90	48.15	20.67	86.00

Table 5.9 Scheme 2: Development index prediction for 20 years

Index time	Cumulative oil production (m^3)	Recovery degree (%)	Formation pressure (MPa)	Water cut (%)
0	0	0	23.96	0
2	75823.4	6.59	23.48	0.11
4	151672.9	13.19	23.19	0.08
6	227507	19.79	22.86	0.23
8	301921.7	26.26	22.50	4.54
10	372364.2	32.39	22.07	10.18
12	436040.8	37.93	21.56	22.65
14	488043.3	42.45	21.19	40.88
16	525957.3	45.75	21.00	59.80
18	548663.6	47.72	21.01	77.50
20	562595.9	48.94	21.15	84.40

So, the Scheme 3 can achieve the best development effect. This is mainly because the reservoir properties of the river sedimentary micro-facies are good and the permeability distribution is regular due to the influence of the source direction. The line injection well pattern can achieve the best development effect when the primary permeability direction is consistent with the direction of the waterflooding direction. On the other hand, the five-spot well pattern is suitable for sheet sand sedimentary micro-facies, for the source direction has little effect on permeability distribution.

The simulation results show that different sedimentary micro-facies match different well patterns. The five-spot well pattern is suitable for developing the sheet sand sedimentary micro-facies. And the line well pattern matches the river sedimentary micro-facies, for the source direction has a great effect on permeability distribution.

Table 5.10 Scheme 3: Development index prediction for 20 years

Index time	Cumulative oil production (m^3)	Recovery degree (%)	Formation pressure (MPa)	Water cut (%)
0	0	0	23.96	0
2	75823.7	6.59	23.48	0.110
4	151674.5	13.19	23.19	0.078
6	227541.4	19.79	22.86	0.063
8	303401.3	26.39	22.49	3.130
10	378280.3	32.90	22.02	8.050
12	444779.6	38.69	21.47	20.800
14	495841.7	43.13	21.10	38.130
16	530615.0	46.15	20.94	60.520
18	552880.3	48.09	20.95	74.070
20	567971.1	49.40	21.07	82.220

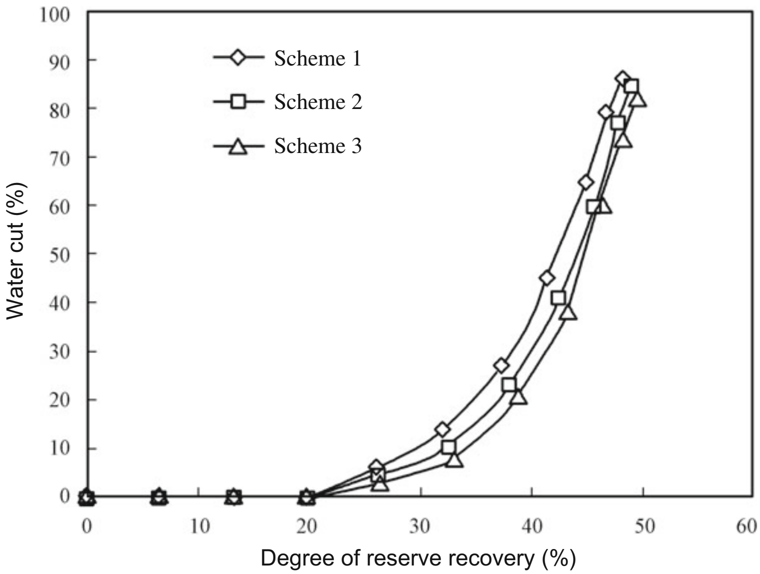


Fig. 5.12 Relation curves of recovery degree and water cut for different schemes

5.3.2 *Influence of Well Spacing Densities of Different Micro-facies on the Development Effect*

In order to investigate the influence of well spacing density of different micro-facies on development effects, three schemes (Fig. 5.13) are designed by using the same geologic model. For the five-spot well pattern, the line well pattern, and the combination well pattern of the two, the development effects of different well

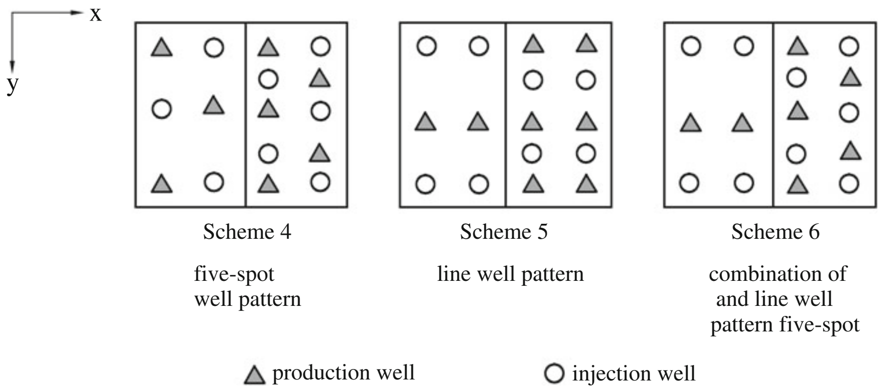


Fig. 5.13 Well patterns for different combinations of sedimentary micro-facies (2)

Table 5.11 Scheme 4: Development index prediction for 20 years

Index time	Cumulative oil production (m^3)	Recovery degree (%)	Formation pressure (MPa)	Water cut (%)
0	0	0	23.96	0
2	75823.84	6.59	23.46	0.109
4	157505.90	13.70	23.15	0.092
6	236270.40	20.55	22.80	0.113
8	304048.10	26.44	22.41	1.990
10	389892.30	33.91	21.90	10.340
12	456466.50	39.71	21.31	22.520
14	506551.70	44.06	20.95	40.650
16	539687.80	46.94	20.80	60.520
18	562790.00	48.95	20.80	72.820
20	579753.60	50.43	20.90	81.340

spacing density for different sedimentary micro-facies are studied under the same oil recovery rate of 3 %.

The simulation results of the three schemes above have been considered in the design of the well patterns. The present schemes are actually the diluted combination of river channel micro-facies in the three schemes in Fig. 5.13.

The development indexes of different well schemes are shown in Tables 5.11, 5.12, and 5.13. The comparison of the indexes of the schemes is shown in Fig. 5.14.

Due to the good reservoir properties of river sedimentary micro-facies, relatively sparse well network can effectively control the reservoir reserves. However, the relatively dense well network should be used in sheet sand sedimentary micro-facies because of the poor reservoir properties.

From the figures and tables above, certain adjustments in well density are made based on Scheme 1, Scheme 2, and Scheme 3 according to the physical properties

Table 5.12 Scheme 5: Development index prediction for 20 years

Index time	Cumulative oil production (m^3)	Recovery degree (%)	Formation pressure (MPa)	Water cut (%)
0	0	0	23.96	0
2	75823.91	6.59	23.48	0.110
4	157674.90	13.71	23.19	0.093
6	237539.40	20.66	22.86	0.100
8	323304.00	28.12	22.49	2.620
10	395712.30	34.42	22.07	7.570
12	462623.20	40.24	21.49	23.570
14	515496.10	44.84	21.07	42.770
16	542983.50	47.23	20.83	58.130
18	567228.70	49.34	20.71	70.770
20	591582.50	51.46	20.69	80.850

Table 5.13 Scheme 6: Development index prediction for 20 years

Index time	Cumulative oil production (m^3)	Recovery degree (%)	Formation pressure (MPa)	Water cut (%)
0	0	0	23.96	0
2	75823.91	6.59	23.44	0.110
4	158130.90	13.75	23.10	0.093
6	253432.90	22.05	22.71	0.110
8	334359.50	29.08	22.30	2.270
10	407861.90	35.48	21.75	7.050
12	472001.30	41.07	21.20	21.040
14	524756.30	45.65	20.80	41.640
16	564638.60	49.12	20.58	57.930
18	589065.80	51.24	20.58	70.010
0	604494.40	52.58	20.72	80.160

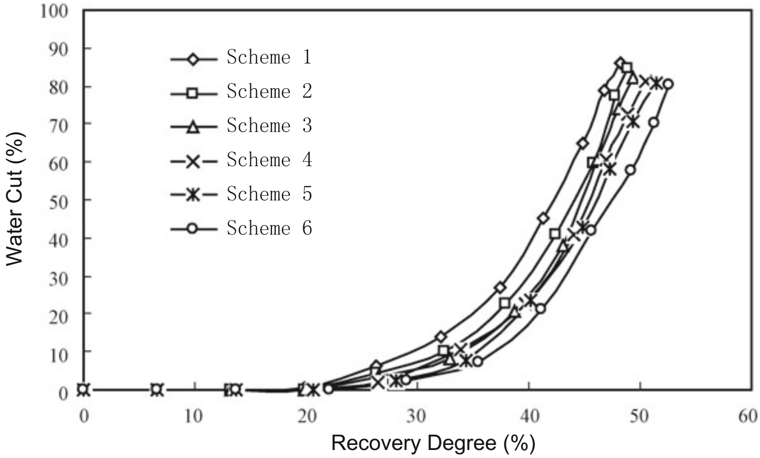


Fig. 5.14 Relation curves of recovery degree and water cut for different schemes (2)

of the different sedimentary micro-facies. The development indexes of the adjusted schemes are much better than the unadjusted ones. The overall development effect of Scheme 6 is the best.

The simulation results prove that better development effects and economic benefits can be achieved by designing a reasonable well pattern according to the different sedimentary micro-facies.

5.4 Well Patterns in the Vertical Heterogeneous Reservoir

Controlled by the river sedimentary micro-facies, most of the sandstone reservoirs in China are characterized by multiple layers in the vertical direction. Because of the swing of the river channel, the reservoirs deposited in different periods show different sedimentary features and different layers show different sedimentary micro-facies. For the sand bodies of river sedimentary micro-facies, the permeability directivity is the most direct reflection of the phase transition, and the permeability directivity is the key factor which influences the well pattern deployment and the waterflooding development effect.

5.4.1 Construction of the Theoretical Geologic Model

In order to study a suitable well pattern for the vertical multilayer reservoir, a theoretical geologic model is built with Petrel software. The model is used to present the reservoir composite situation of the two vertical layers with different permeability directions. A numerical simulation software is used to simulate different well patterns and different well pattern directions to optimize reasonable well patterns of different model combinations.

1. Grid system

The grid step length of the model is 10 m × 10 m on the plane. Vertically, there are two layers, and every layer is 10 m thick. The grid numbers are 51 × 51 × 2 = 5202. The length and width of the reservoir plane are 510 and 510 m, respectively, and the area is 260,100 m^2 as shown in Fig. 5.15.

2. Parameter model

The porosity of the model is 0.25. The maximum permeability and minimum permeability are 20×10^{-3} μm^2 and 5×10^{-3} μm^2, respectively. The model is built according to the river sedimentary micro-facies, which means that the river channel direction is the primary permeability direction and the minimum permeability direction is vertical to the river channel direction. In this vertical direction, permeability decreases gradually from channel axis to the outer area. There are various combinations of the two layers in the vertical direction. According to the oilfield developing and understanding, several combination schemes are shown as follows:

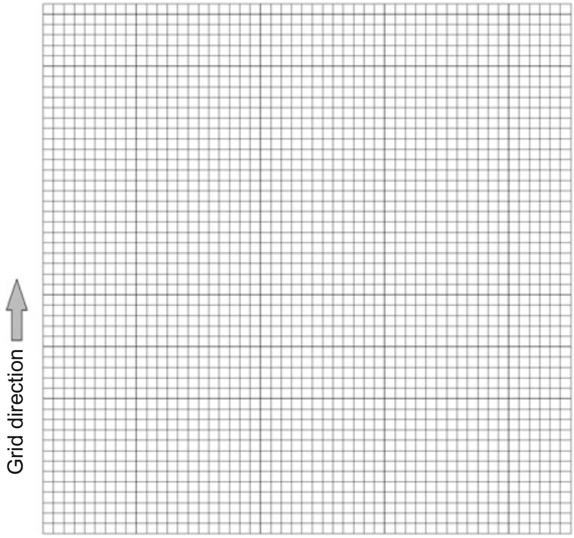
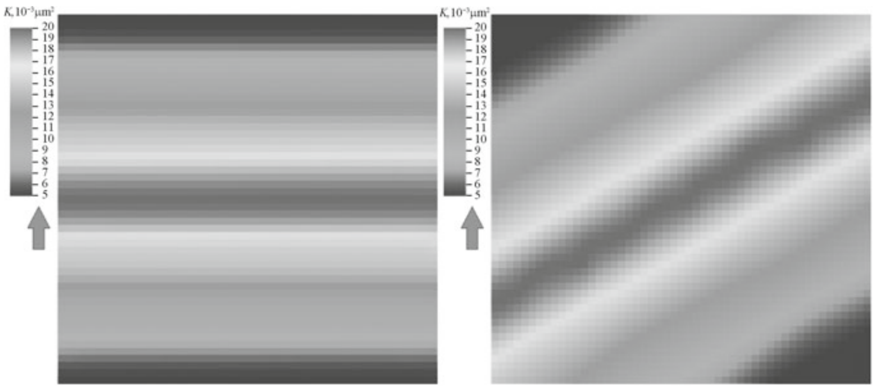


Fig. 5.15 Grid system of theoretical model

(a) The angle of the primary permeability directions between the first layer and the second layer is 15°. The reservoir parameters of different layers are shown in Fig. 5.16.

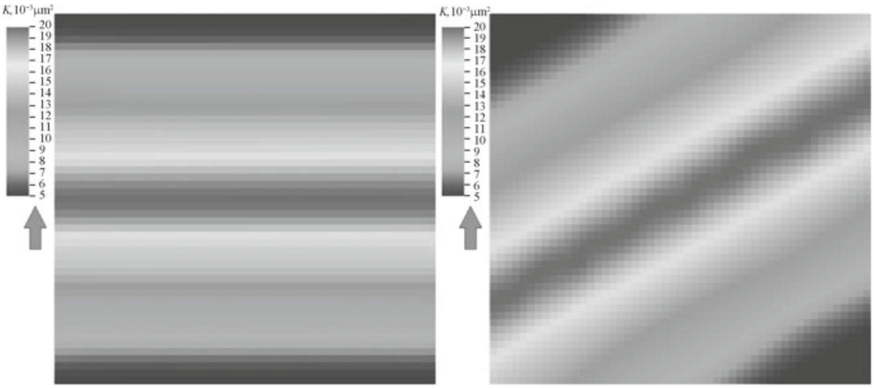
(b) The angle of the primary permeability directions between the first layer and the second layer is 30°. The reservoir parameters of different layers are shown in Fig. 5.17.



(a) permeability distribution of the first layer

(b) permeability distribution of the second layer

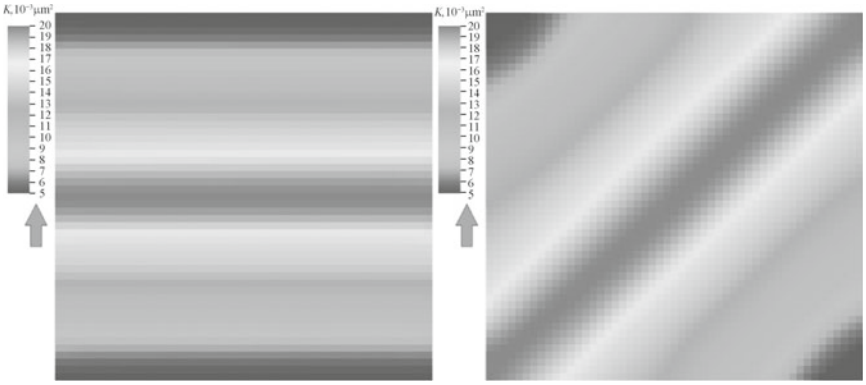
Fig. 5.16 The distribution of reservoir parameter when the main permeability directions form an angle of 15°



(a) permeability distribution of the first layer

(b) permeability distribution of the second layer

Fig. 5.17 The distribution of reservoir parameter when the main permeability directions form an angle of 30°

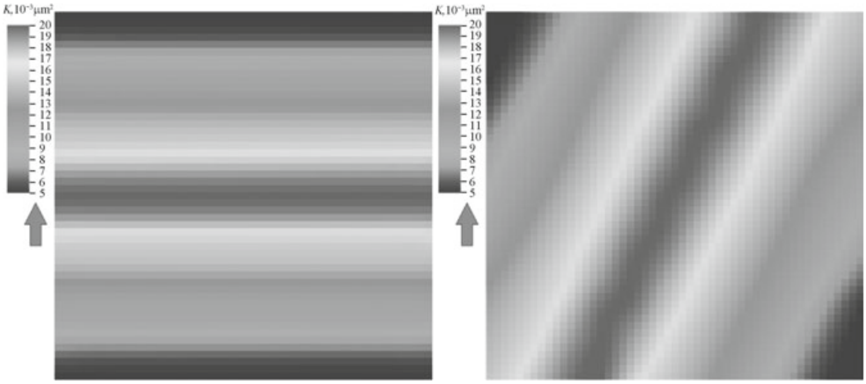


(a) permeability distribution of the first layer

(b) permeability distribution of the second layer

Fig. 5.18 The distribution of reservoir parameter when the main permeability directions form an angle of 45°

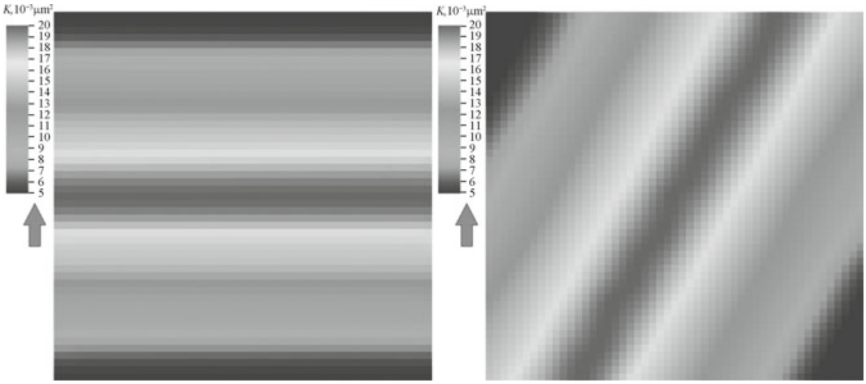
(c) The angle of the primary permeability directions between the first layer and the second layer is 45°. The reservoir parameters of different layers are shown in Fig. 5.18.
(d) The angle of the primary permeability directions between the first layer and the second layer is 60°. The reservoir parameters of different layers are shown in Fig. 5.19.



(a) permeability distribution of the first layer

(b) permeability distribution of the second layer

Fig. 5.19 The distribution of reservoir parameter when the main permeability directions form an angle of 60°

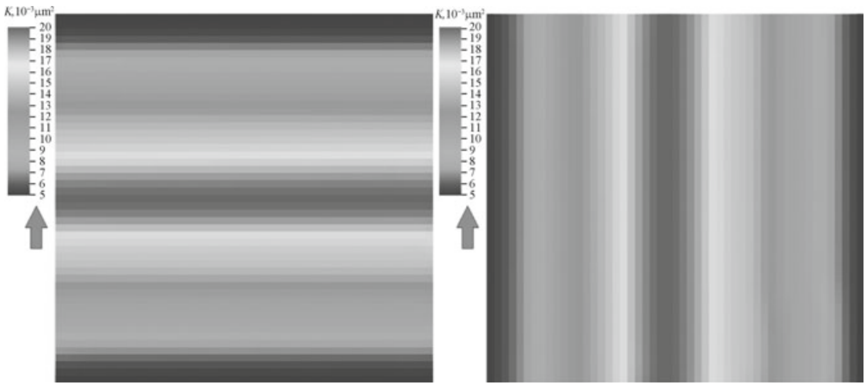


(a) permeability distribution of the first layer

(b) permeability distribution of the second layer

Fig. 5.20 The distribution of reservoir parameter when the main permeability directions form an angle of 75°

(e) The angle of the primary permeability directions between the first layer and the second layer is 75°. The reservoir parameters of different layers are shown in Fig. 5.20.
(f) The angle of the primary permeability directions between the first layer and the second layer is 90°. The reservoir parameters of different layers are shown in Fig. 5.21.



(a) permeability distribution of the first layer

(b) permeability distribution of the second layer

Fig. 5.21 The distribution of reservoir parameter when the main permeability directions form an angle of 90°

5.4.2 Well Pattern Optimization with Two Different Permeability Directions

The five-spot well pattern and the inverted seven-spot well pattern are used to optimize the vector well pattern. Assuming the angle between the line connecting the water injection well and the production well, and the primary permeability direction of the first layer is α, then different vector well patterns can be obtained through changing the numerical magnitude of α. Figure 5.22 shows the vectorization of the five-spot well pattern, and Fig. 5.23 shows the vectorization of the inverted seven-spot well pattern.

1. The angle of the primary permeability directions between the first layer and the second layer is 15°. Through changing α, different well patterns are designed to optimize the well pattern.

(a) Cases of the vector well pattern

Case 1: the five-spot well pattern with $\alpha = 0°$;
Case 2: the five-spot well pattern with $\alpha = 22.5°$;
Case 3: the five-spot well pattern with $\alpha = 45°$;
Case 4: the inverted seven-spot well pattern with $\alpha = 0°$;
Case 5: the inverted seven-spot well pattern with $\alpha = 22.5°$;
Case 6: the inverted seven-spot well pattern with $\alpha = 45°$.

(b) Comparative analysis of development effects

Different cases of well patterns are simulated with the same model requirements and simulation time of 1600 days.

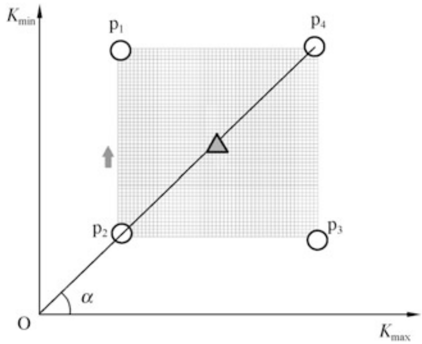


Fig. 5.22 Scheme of five-spot well pattern

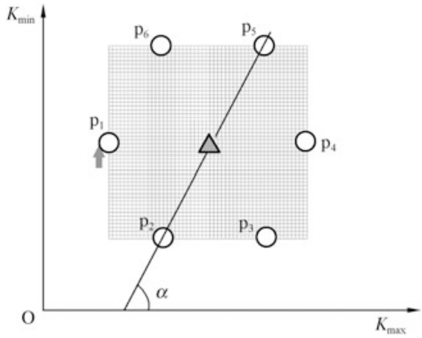


Fig. 5.23 Scheme of inverted seven-spot well pattern

– Water breakthrough time in different cases

The simulation results of different cases are shown in Figs. 5.24, 5.25, 5.26, 5.27, 5.28, 5.29, and 5.30.

– Relation curves of water cut and recovery degree (Fig. 5.30).

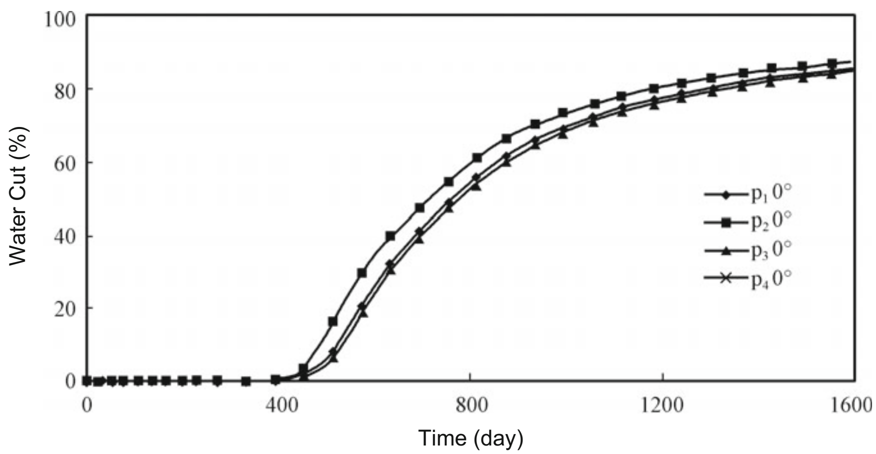


Fig. 5.24 Relation curves of water breakthrough time and water cut for every production well in Case 1

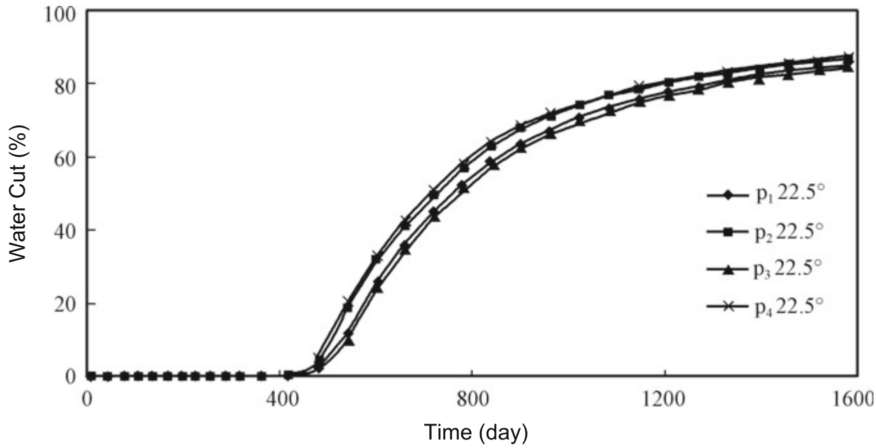


Fig. 5.25 Relation curves of water breakthrough time and water cut for every production well in Case 2

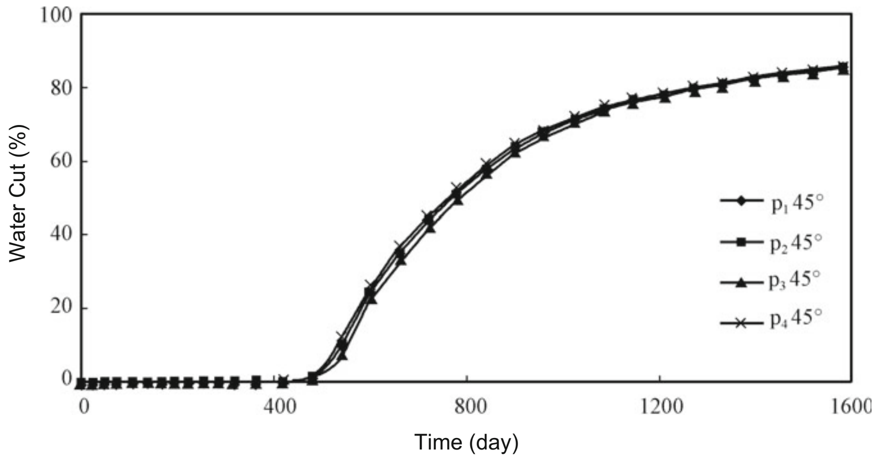


Fig. 5.26 Relation curves of water breakthrough time and water cut for every production well in Case 3

Figure 5.30 shows that the development effect of Case 6 is the best. Hence, the inverted seven-spot well pattern with $\alpha = 45°$ should be chosen for the reservoir in which the angle of the primary permeability directions between the first layer and the second layer is 15°.

2. The angle of the primary permeability directions between the first layer and the second layer is 30°. Through changing α, different well patterns are designed to optimize the well pattern.

(a) Cases of the vector well pattern

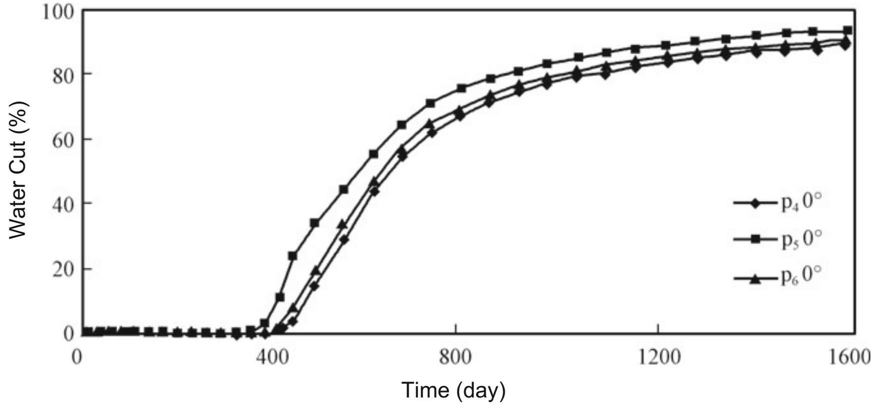


Fig. 5.27 Relation curves of water breakthrough time and water cut for every production well in Case 4

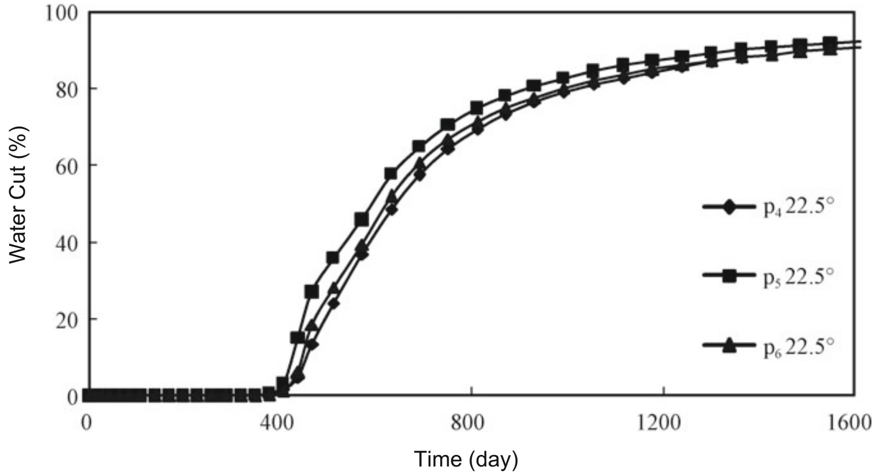


Fig. 5.28 Relation curves of water breakthrough time and water cut for every production well in Case 5

Case 1: the five-spot well pattern with $\alpha = 0°$;
Case 2: the five-spot well pattern with $\alpha = 22.5°$;
Case 3: the five-spot well pattern with $\alpha = 45°$;
Case 4: the inverted seven-spot well pattern with $\alpha = 0°$;
Case 5: the inverted seven-spot well pattern with $\alpha = 22.5°$;
Case 6: the inverted seven-spot well pattern with $\alpha = 45°$.

(b) Comparative analysis of development effects

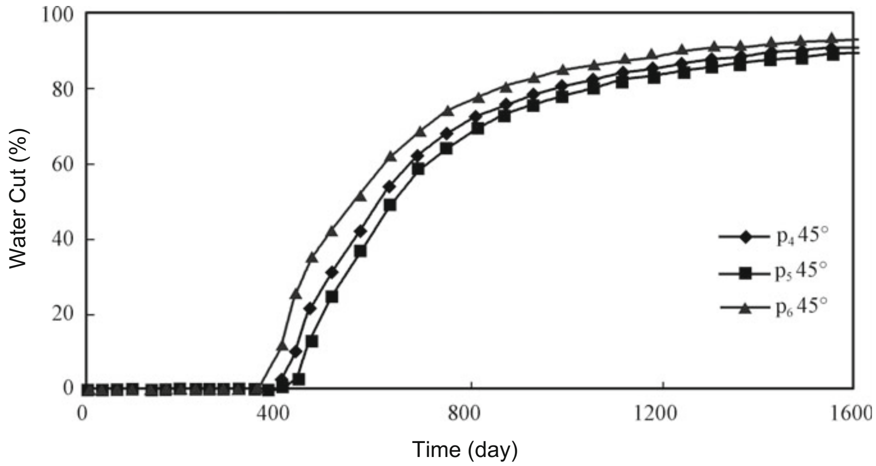


Fig. 5.29 Relation curves of water breakthrough time and water cut for every production well in Case 6

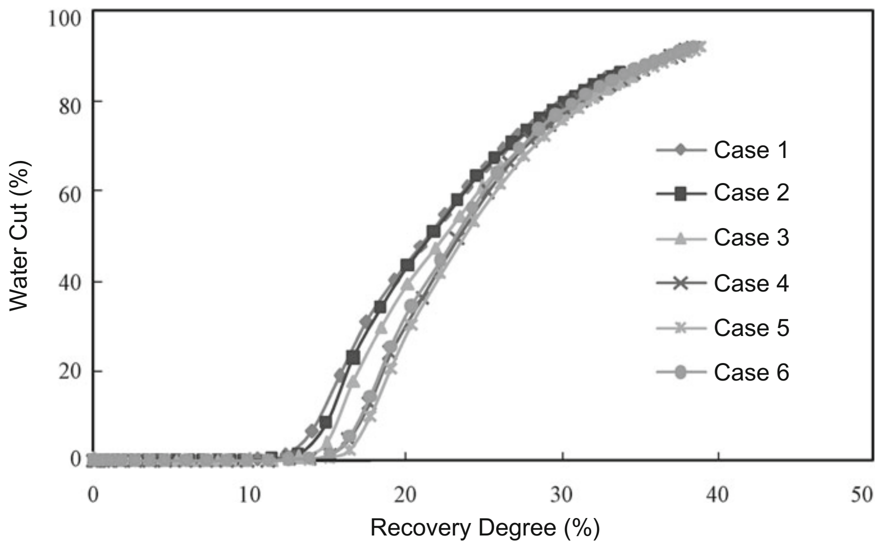


Fig. 5.30 Relation curves of water cut and recovery degree of different cases

Different cases of well patterns are simulated with the same model requirements and simulation time of 1600 days.

– Water breakthrough time of different cases

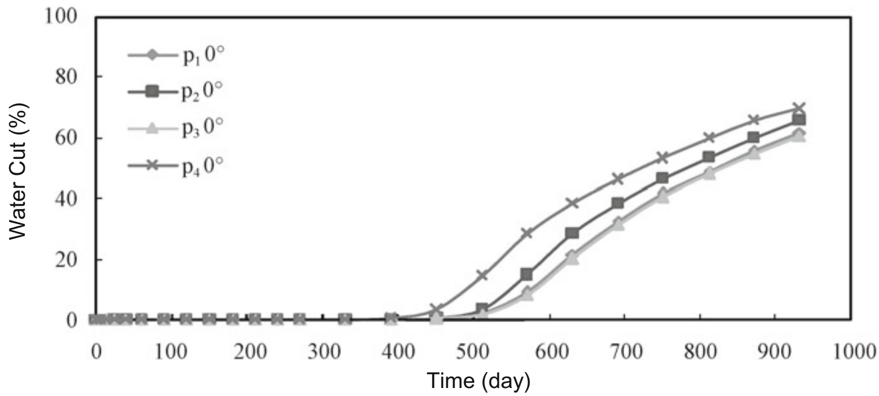


Fig. 5.31 Relation curves of water breakthrough time and water cut for every production well in Case 1

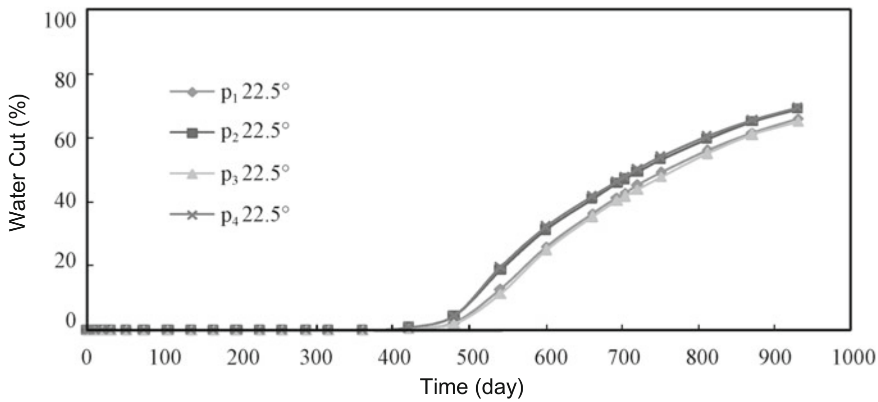


Fig. 5.32 Relation curves of water breakthrough time and water cut for every production well in Case 2

The simulation results of different cases are shown in Figs. 5.31, 5.32, 5.33, 5.34, 5.35, and 5.36.

– Relation curves of water cut and recovery degree (Fig. 5.37)

Figure 5.37 shows that the development effect of Case 4 is the best. Hence, the inverted seven-spot well pattern with $\alpha = 0°$ should be chosen for the reservoir in which the angle of the primary permeability directions between the first layer and the second layer is 30°.

3. The angle of the primary permeability directions between the first layer and the second layer is 45°. Through changing α, different well patterns are designed to optimize the well pattern.

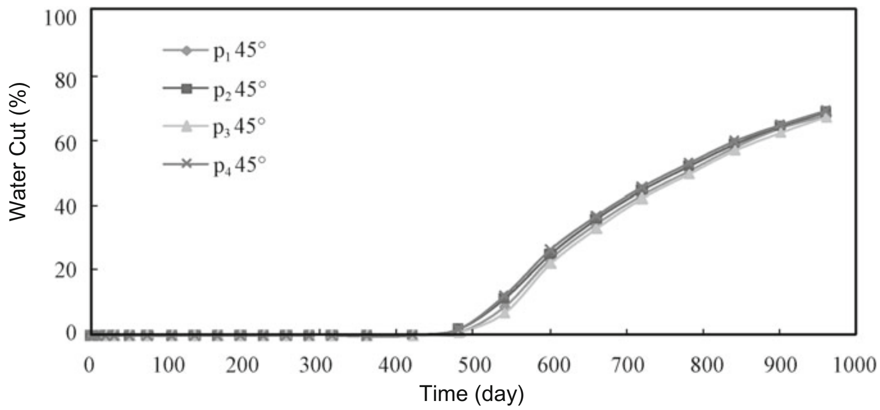


Fig. 5.33 Relation curves of water breakthrough time and water cut for every production well in Case 3

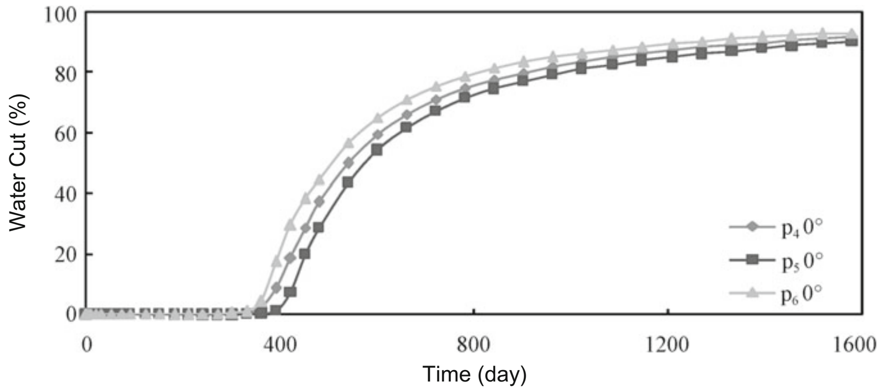


Fig. 5.34 Relation curves of water breakthrough time and water cut for every production well in Case 4

(a) Cases of the vector well pattern

Case 1: the five-spot well pattern with $\alpha = 0°$;
Case 2: the five-spot well pattern with $\alpha = 22.5°$;
Case 3: the five-spot well pattern with $\alpha = 45°$;
Case 4: the inverted seven-spot well pattern with $\alpha = 0°$;
Case 5: the inverted seven-spot well pattern with $\alpha = 22.5°$;
Case 6: the inverted seven-spot well pattern with $\alpha = 45°$.

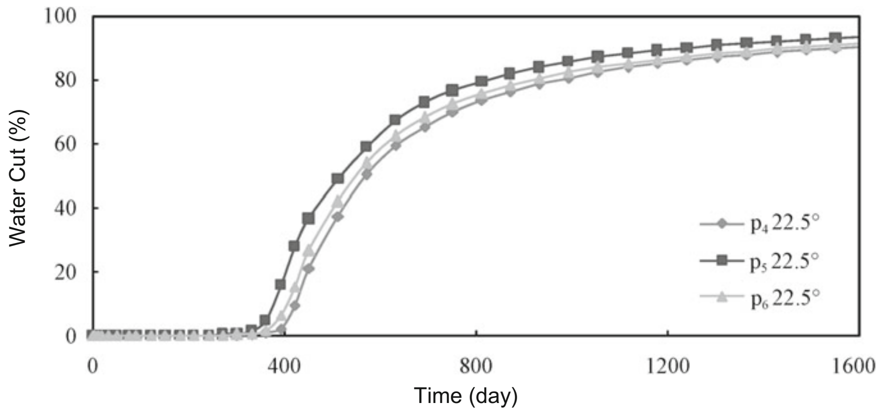


Fig. 5.35 Relation curves of water breakthrough time and water cut for every production well in Case 5

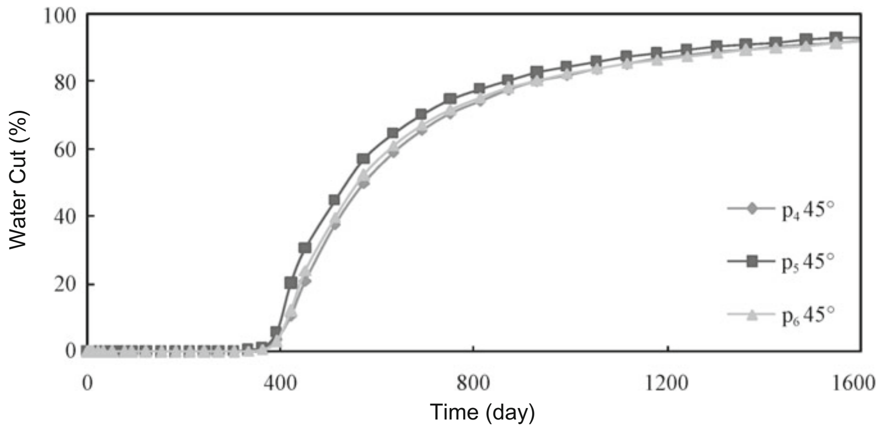


Fig. 5.36 Relation curves of water breakthrough time and water cut for every production well in Case 6

(b) Comparative analysis of development effects

Different cases of well patterns are simulated with the same model requirements and simulation time of 1600 days.

– Water breakthrough time of different cases

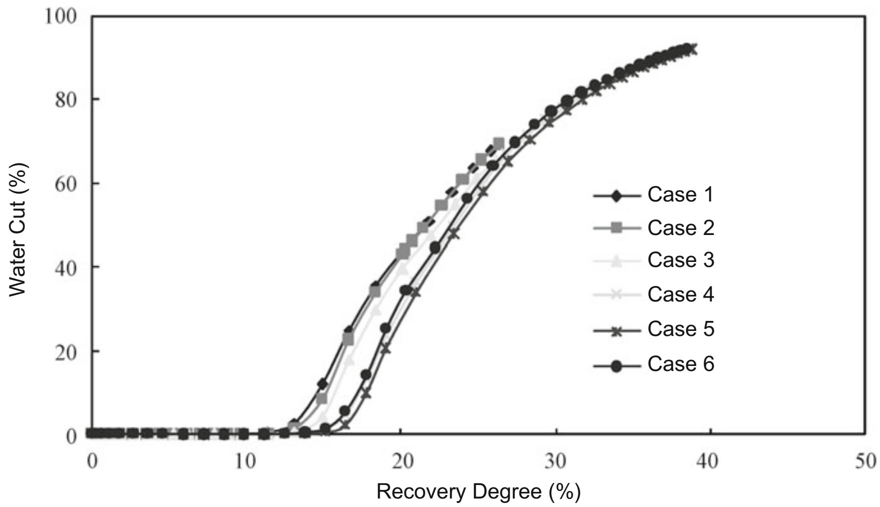


Fig. 5.37 Relation curves of water cut and recovery degree of different cases

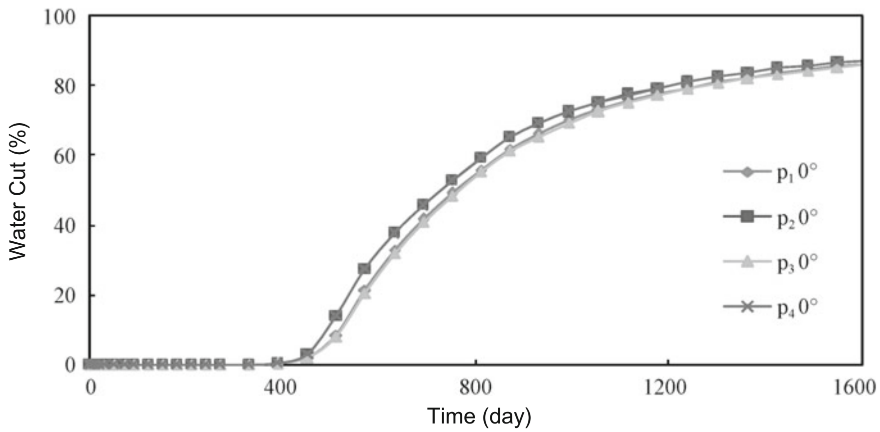


Fig. 5.38 Relation curves of water breakthrough time and water cut for every production well in Case 1

The simulation results of different cases are shown in Fig. 5.38, 5.39, 5.40, 5.41, 5.42, and 5.43.

– Relation curves of water cut and recovery degree (Fig. 5.44)

Figure 5.44 shows that the development effect of Case 6 is the best. Hence, the inverted seven-spot well pattern with $\alpha = 45°$ should be chosen for the reservoir in

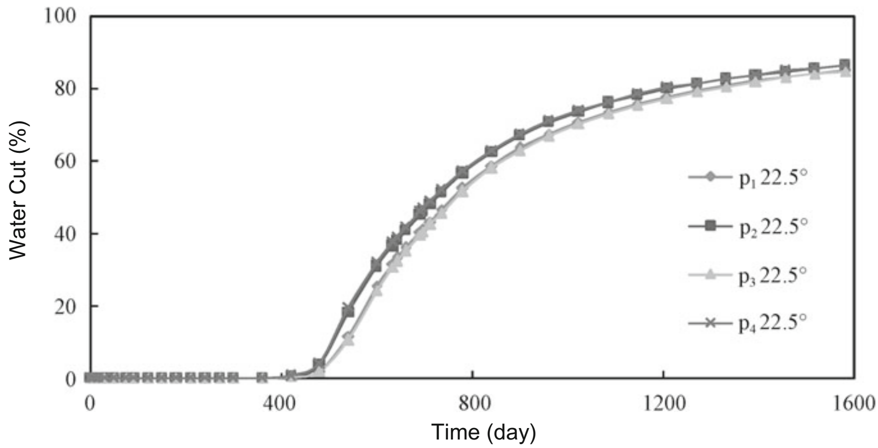


Fig. 5.39 Relation curves of water breakthrough time and water cut for every production well in Case 2

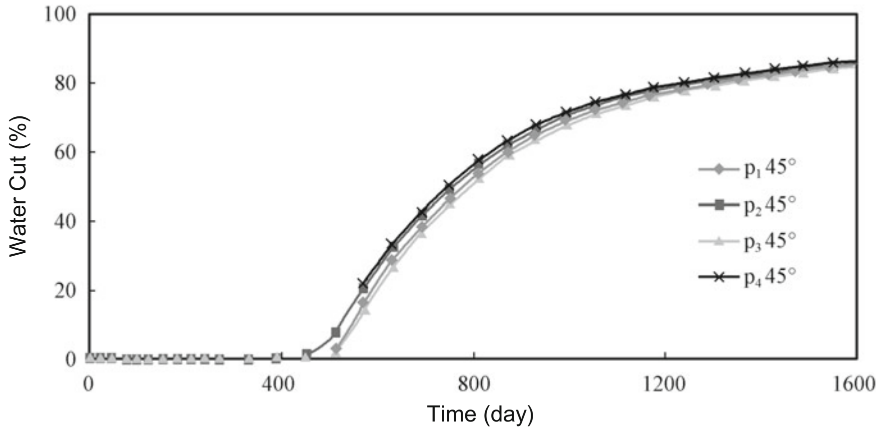


Fig. 5.40 Relation curves of water breakthrough time and water cut for every production well in Case 3

which the angle of the primary permeability directions between the first layer and the second layer is 45°.

4. The angle of the primary permeability directions between the first layer and the second layer is 60°. Through changing α, different well patterns are designed to optimize the well pattern.

(a) Cases of the vector well pattern

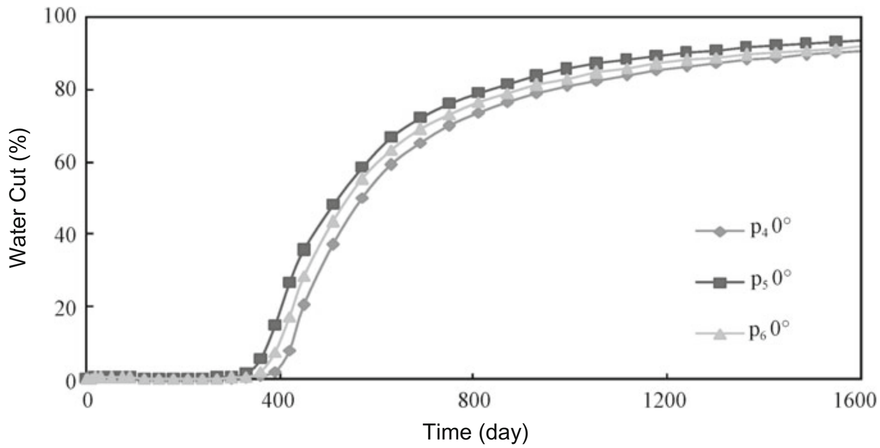


Fig. 5.41 Relation curves of water breakthrough time and water cut for every production well in Case 4

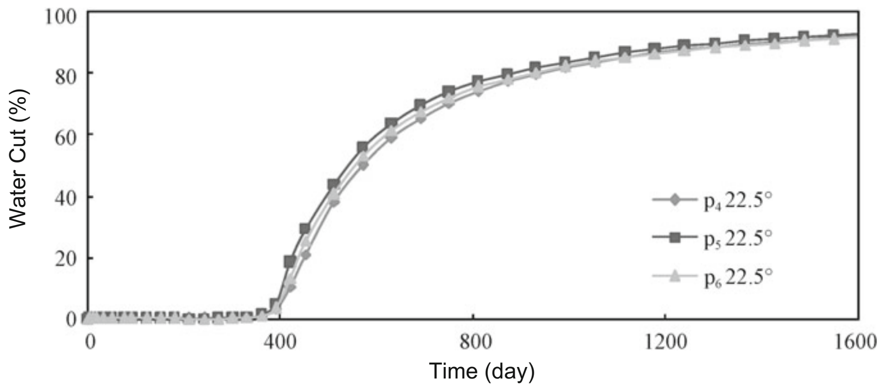


Fig. 5.42 Relation curves of water breakthrough time and water cut for every production well in Case 5

Case 1: the five-spot well pattern with $\alpha = 0°$;
Case 2: the five-spot well pattern with $\alpha = 22.5°$;
Case 3: the five-spot well pattern with $\alpha = 45°$;
Case 4: the inverted seven-spot well pattern with $\alpha = 0°$;
Case 5: the inverted seven-spot well pattern with $\alpha = 22.5°$;
Case 6: the inverted seven-spot well pattern with $\alpha = 45°$.

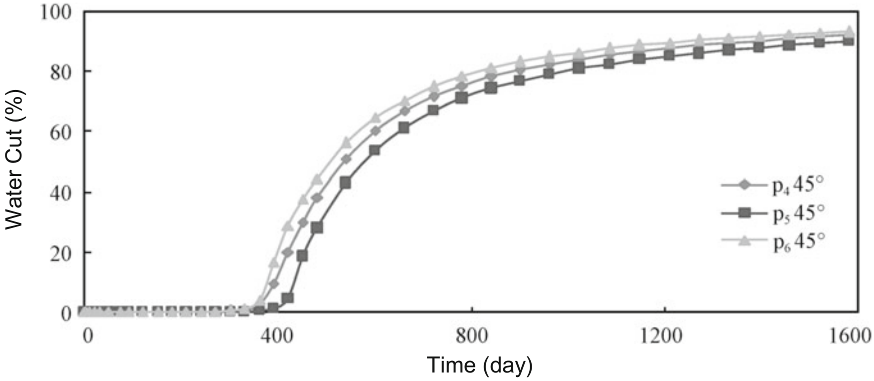


Fig. 5.43 Relation curves of water breakthrough time and water cut for every production well in Case 6

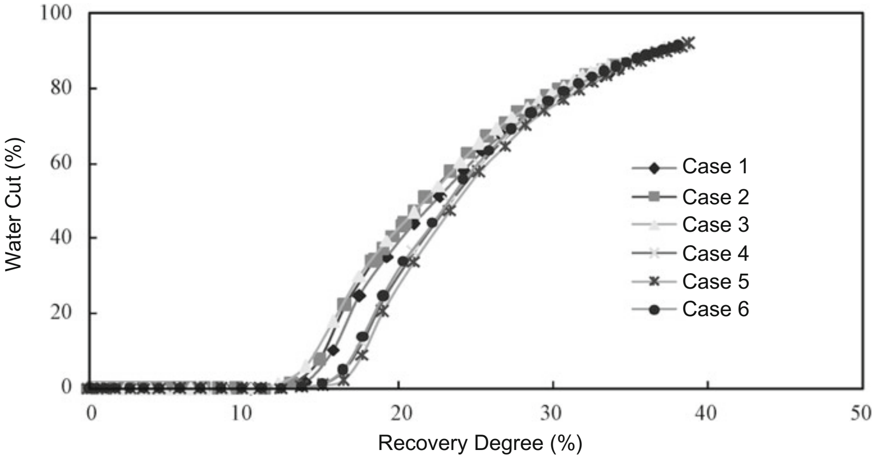


Fig. 5.44 Relation curves of water cut and recovery degree of different cases

(b) Comparative analysis of development effects

Different cases of well patterns are simulated with the same model requirements and simulation time of 1600 days.

– Water breakthrough time of different cases

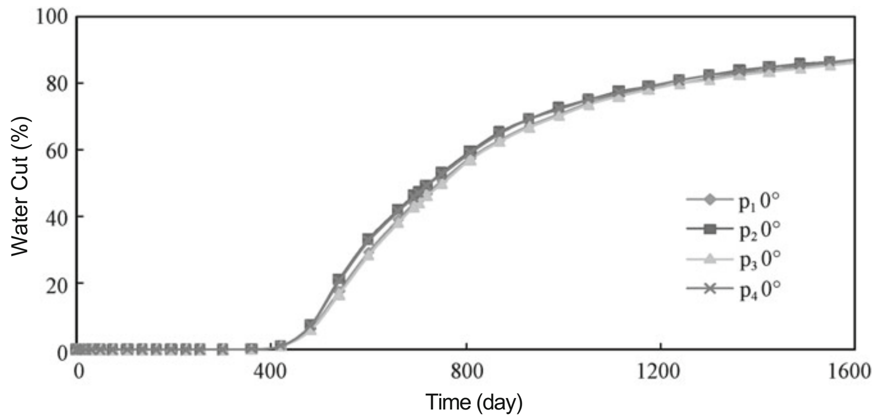


Fig. 5.45 Relation curves of water breakthrough time and water cut for every production well in Case 1

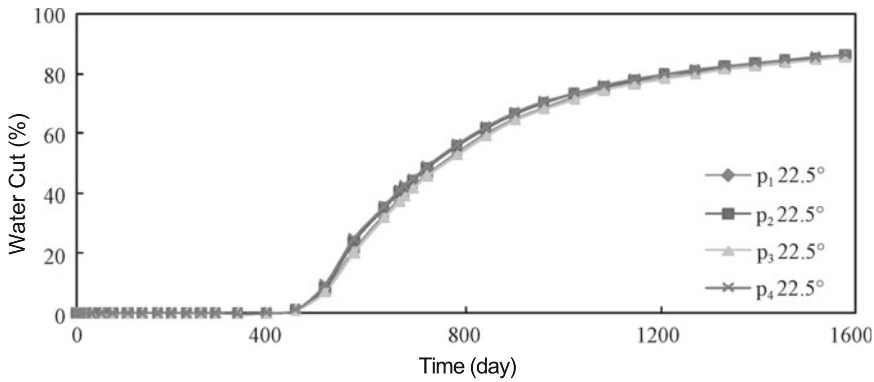


Fig. 5.46 Relation curves of water breakthrough time and water cut for every production well in Case 2

The simulation results of different cases are shown in Fig. 5.45, 5.46, 5.47, 5.48, 5.49, and 5.50.

– Relation curves of water cut and recovery degree (Fig. 5.51)

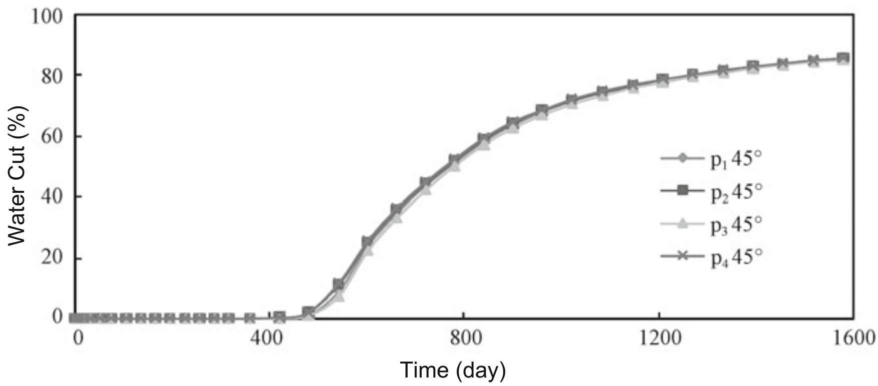


Fig. 5.47 Relation curves of water breakthrough time and water cut for every production well in Case 3

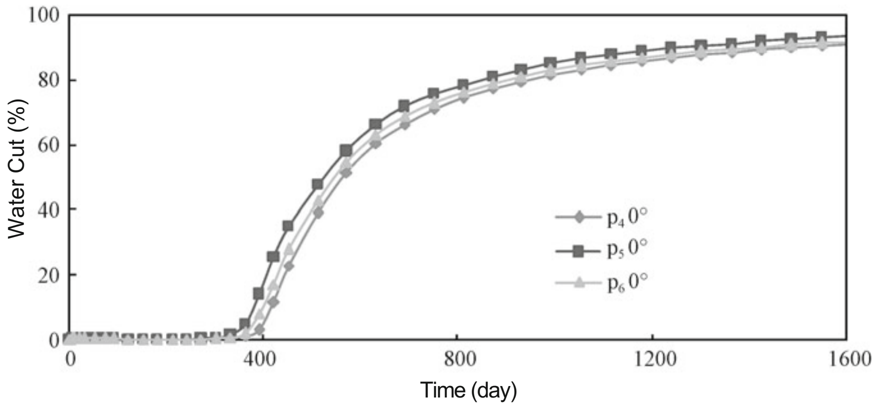


Fig. 5.48 Relation curves of water breakthrough time and water cut for every production well in Case 4

Figure 5.51 shows that the development effect of Case 5 is the best. Hence, the inverted seven-spot well pattern with $\alpha = 22.5°$ should be chosen for the reservoir in which the angle of the primary permeability directions between the first layer and the second layer is 60°.

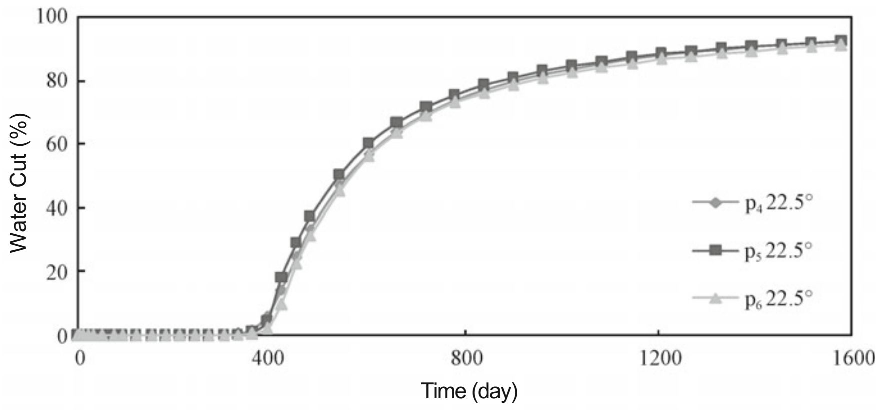


Fig. 5.49 Relation curves of water breakthrough time and water cut for every production well in Case 5

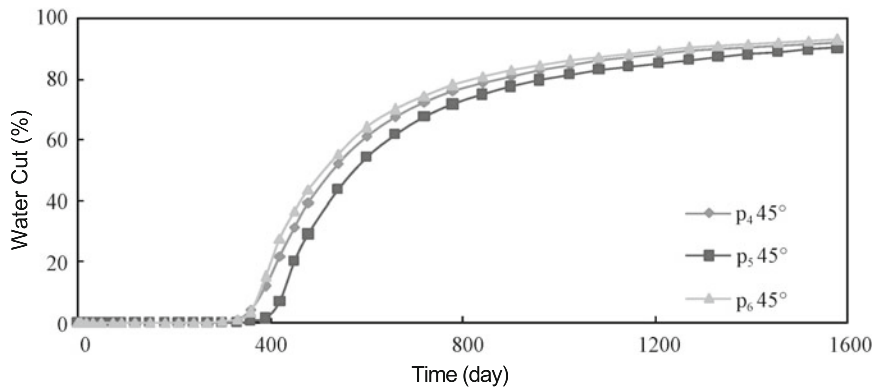


Fig. 5.50 Relation curves of water breakthrough time and water cut for every production well in Case 6

5. The angle of the primary permeability directions between the first layer and the second layer is 75°. Through changing α, different well patterns are designed to optimize the well pattern.

(a) Cases of the vector well pattern

Case 1: the five-spot well pattern with $\alpha = 0°$;
Case 2: the five-spot well pattern with $\alpha = 22.5°$;
Case 3: the five-spot well pattern with $\alpha = 45°$;

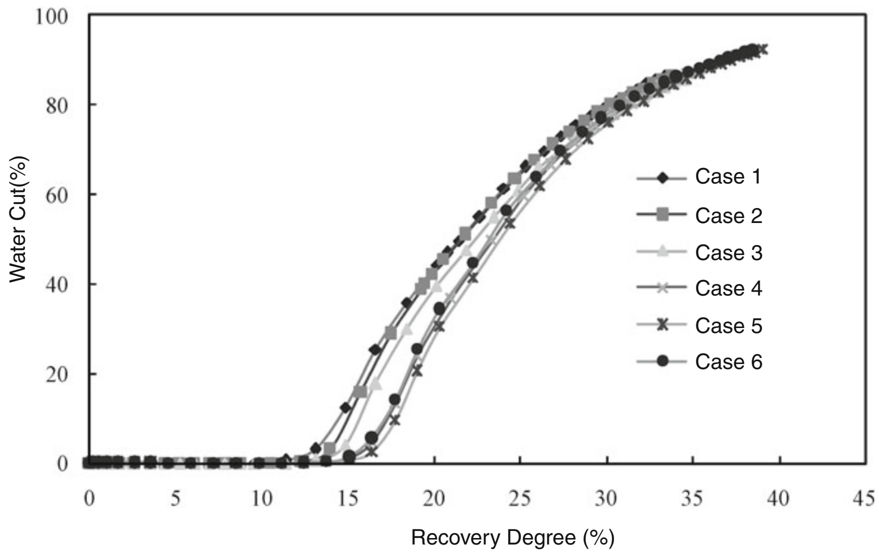


Fig. 5.51 Relation curves of water cut and recovery degree of different cases

Case 4: the inverted seven-spot well pattern with $\alpha = 0°$;
Case 5: the inverted seven-spot well pattern with $\alpha = 22.5°$;
Case 6: the inverted seven-spot well pattern with $\alpha = 45°$.

(b) Comparative analysis of development effects

Different cases of well patterns are simulated with the same model requirements and simulation time of 1600 days.

– Water breakthrough time of different cases

The simulation results of different cases are shown in Figs. 5.52, 5.53, 5.54, 5.55, 5.56, and 5.57.

– Relation curves of water cut and recovery degree (Fig. 5.58)

Figure 5.58 shows that the development effect of Case 5 is the best. Hence, the inverted seven-spot well pattern with $\alpha = 22.5°$ should be chosen for the reservoir in which the angle of the primary permeability directions between the first layer and the second layer is 75°.

6. The angle of the primary permeability directions between the first layer and the second layer is 90°. Through changing α, different well patterns are designed to optimize the well pattern.

(a) Cases of the vector well pattern

Case 1: the five-spot well pattern with $\alpha = 0°$;
Case 2: the five-spot well pattern with $\alpha = 22.5°$;
Case 3: the five-spot well pattern with $\alpha = 45°$;

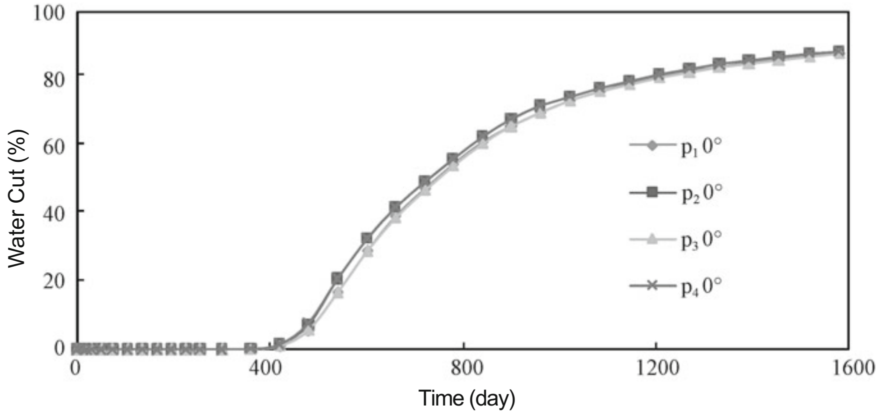


Fig. 5.52 Relation curves of water breakthrough time and water cut for every production well in Case 1

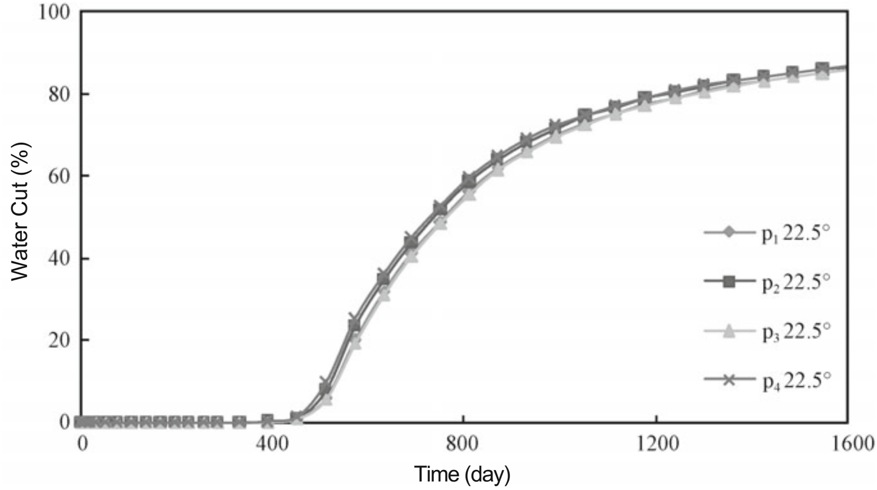


Fig. 5.53 Relation curves of water breakthrough time and water cut for every production well in Case 2

Case 4: the inverted seven-spot well pattern with $\alpha = 0°$;
Case 5: the inverted seven-spot well pattern with $\alpha = 22.5°$;
Case 6: the inverted seven-spot well pattern with $\alpha = 45°$.

b. Comparative analysis of development effects

Different cases of well patterns are simulated with the same model requirements and simulation time of 1600 days.

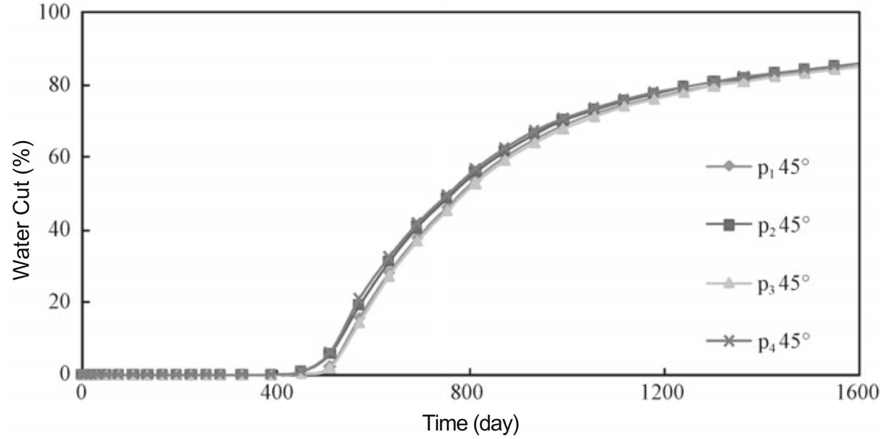


Fig. 5.54 Relation curves of water breakthrough time and water cut for every production well in Case 3

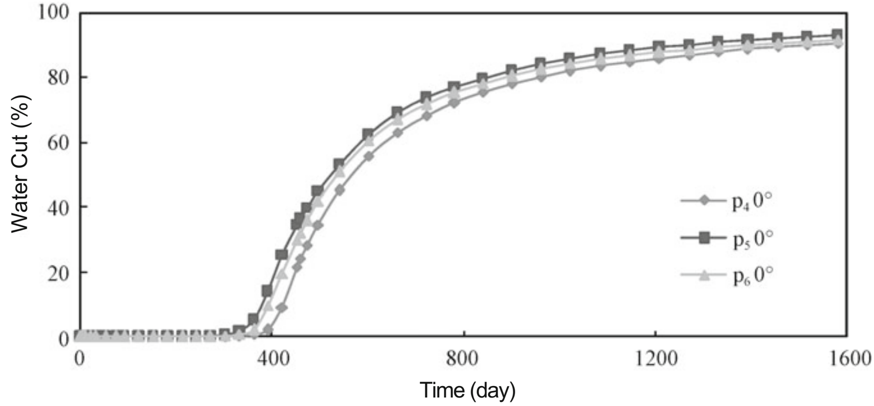


Fig. 5.55 Relation curves of water breakthrough time and water cut for every production well in Case 4

– Water breakthrough time of different cases

The simulation results of different cases are shown in Figs. 5.59, 5.60, 5.61, 5.62, 5.63, and 5.64.

– Relation curves of water cut and recovery degree (Fig. 5.65)

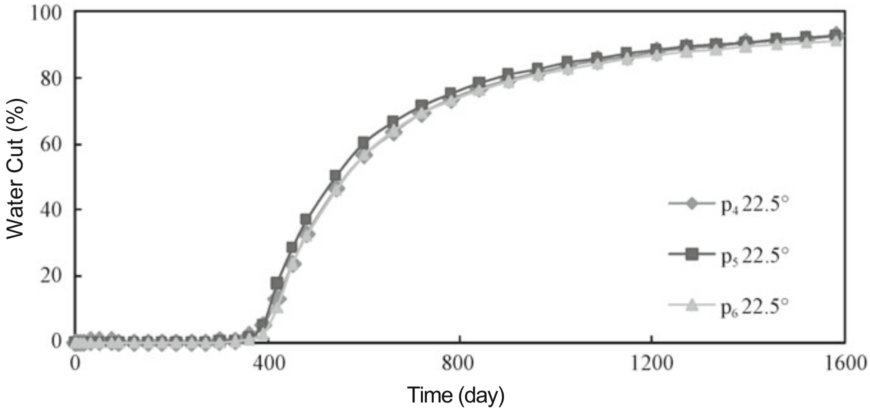


Fig. 5.56 Relation curves of water breakthrough time and water cut for every production well in Case 5

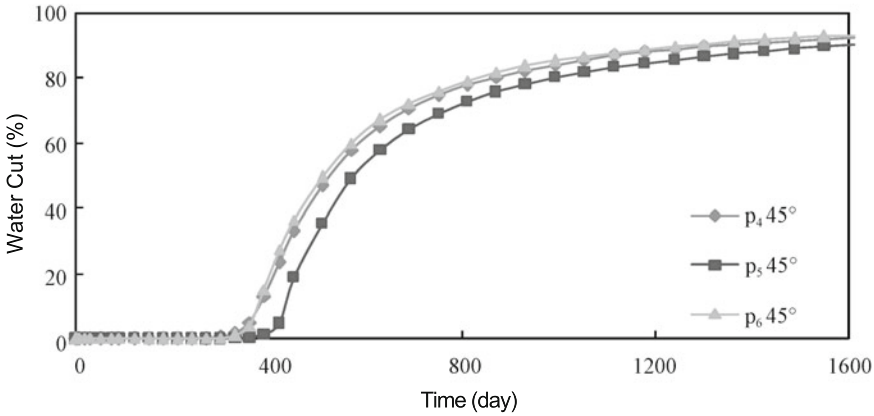


Fig. 5.57 Relation curves of water breakthrough time and water cut for every production well in Case 6

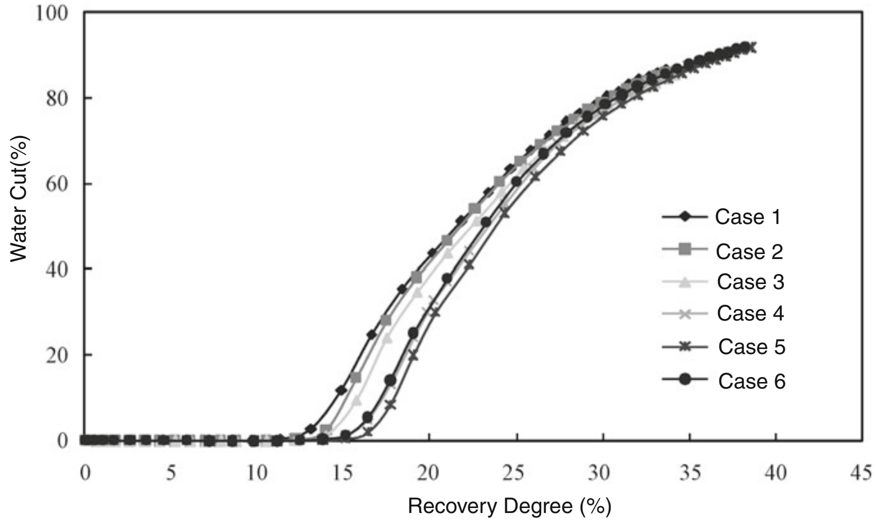


Fig. 5.58 Relation curves of water cut and recovery degree of different cases

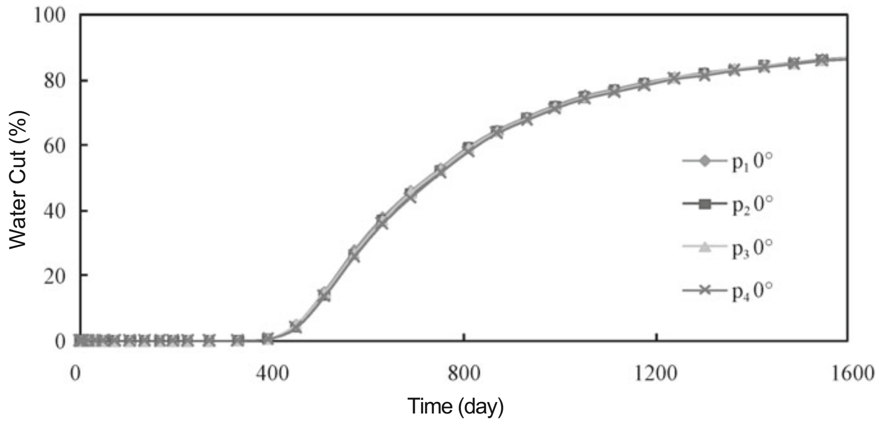


Fig. 5.59 Relation curves of water breakthrough time and water cut for every production well in Case 1

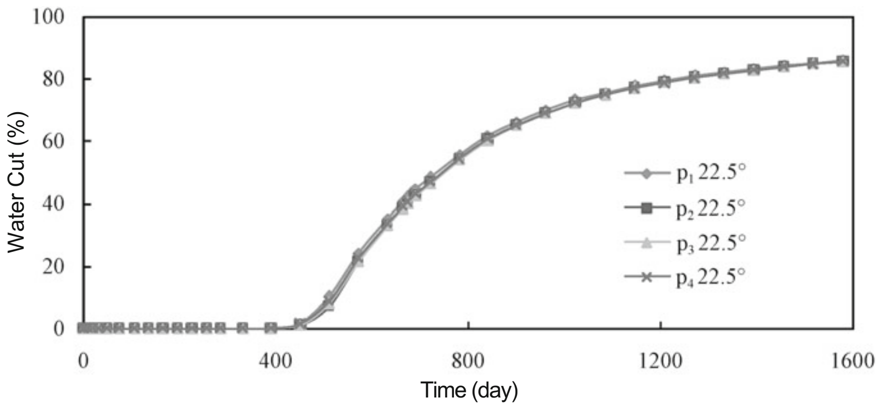


Fig. 5.60 Relation curves of water breakthrough time and water cut for every production well in Case 2

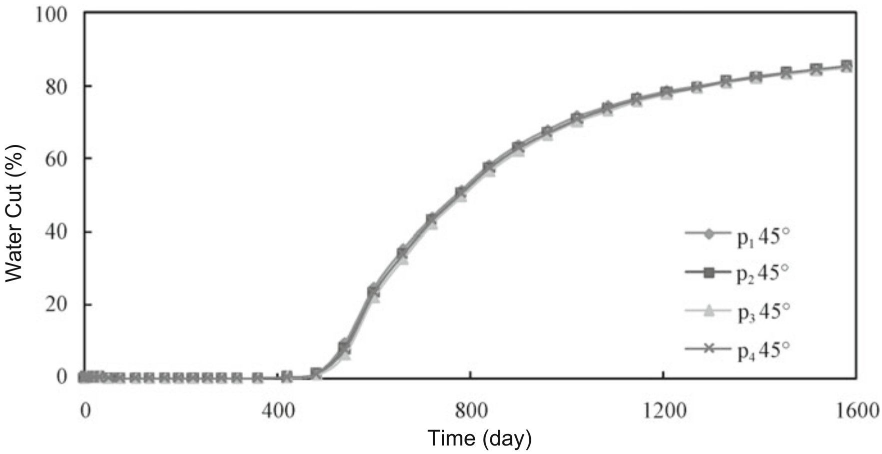


Fig. 5.61 Relation curves of water breakthrough time and water cut for every production well in Case 3

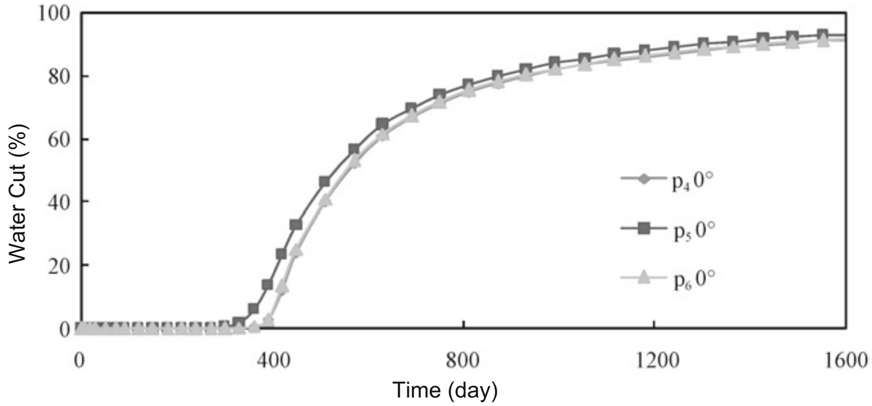


Fig. 5.62 Relation curves of water breakthrough time and water cut for every production well in Case 4

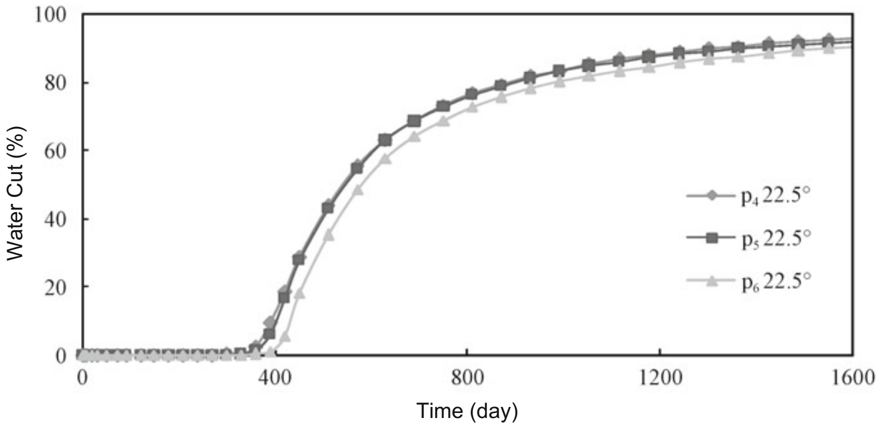


Fig. 5.63 Relation curves of water breakthrough time and water cut for every production well in Case 5

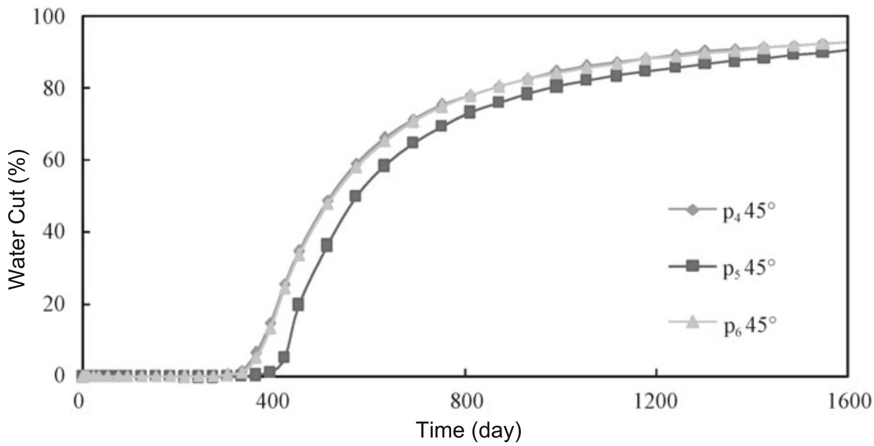


Fig. 5.64 Relation curves of water breakthrough time and water cut for every production well in Case 6

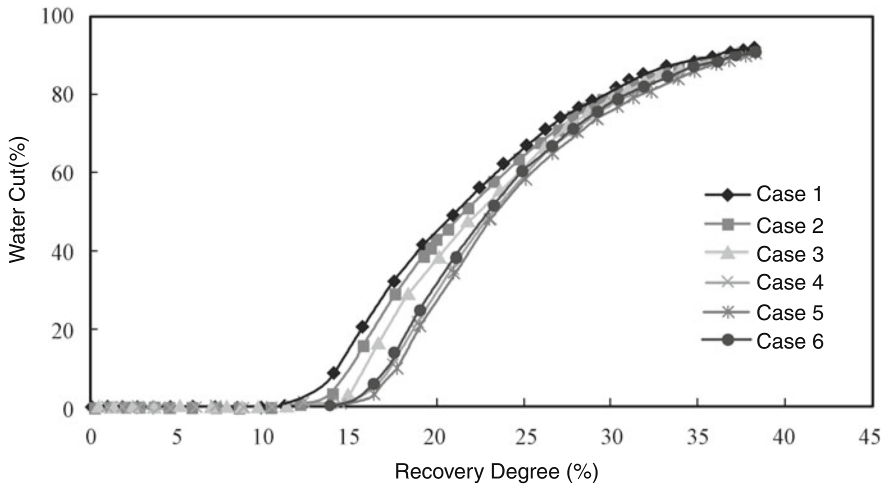


Fig. 5.65 Relation curves of water cut and recovery degree of different cases

Figure 5.65 shows that the development effect of Case 6 is the best. Hence, the inverted seven-spot well pattern with $\alpha = 45°$ should be chosen for the reservoir in which the angle of the primary permeability directions between the first layer and the second layer is 90°.

Chapter 6
Analysis on the Application of the Vector Well Pattern

The previous chapters have described the concept and deployment methods of the vector well pattern. Its theoretical basis is established, and its practical impact on the oilfield development is discussed through theoretical analysis and experiments. This chapter proves the improvement of development effects of the vector well pattern by means of virtual development simulation of the vector well pattern in actual oilfield development.

6.1 Optimal Design and Application of the Vector Well Pattern in Zhao'ao Oilfield

6.1.1 Overview of Zhao'ao Oilfield

This section mainly focuses on the application and analysis of the vector well pattern in the two main reservoirs. One is Zhao'ao reservoir which is located in the main area of Zhao'ao Oilfield, with a laminated oil-bearing area of 3.07 km^2 and a geological reserve of 207×10^4 t; the other is reservoir H_3IV2^{1-3} which is located in the main area of Anpeng oil-bearing zone of 3.5 km^2 with a geological reserve of 246×10^4 t. Both reservoirs have serious interlayer heterogeneity.

1. Overview of H_3IV3^1 in Zhao'ao Oilfield
(a) Simple geological structure with mainly updip lithologic pinchout reservoir

H_3IV3^1 in Zhao'ao Oilfield has a simple structure that gently plunges southeast in a nose-shaped flexure along a northwest–southeast axis, with a dip direction of 128° and a drift angle of 3°42′. It has two asymmetric wings, with its southwest wing slightly steep (5°18′) and the northeast wing slightly lower (3°42′). The reservoir distribution is mainly controlled by structure and lithology, and thus, it is

D. Liu and J. Sun, *The Control Theory and Application for Well Pattern Optimization of Heterogeneous Sandstone Reservoirs*, Springer Geology,
DOI 10.1007/978-3-662-53287-4_6

mainly the updip pinchout reservoir with edge water, controlled by uniclinal structure.

(b) Reservoir sand bodies, mainly from Ping's provenance, are mainly underwater distributary channel deposits

Reservoir sand bodies are mainly from southeast Ping's provenance. The sand deposits are near-provenance steep slope fan delta deposits. From the provenance to the lake district, the fan delta front can be divided into nearshore waterway subfacies, infralittoral waterway subfacies, and end sheet sand subfacies. The nearshore waterway is "fist-shaped," while the infralittoral waterway is "waving circular-shaped," distributed in the front of the nearshore waterway. The end sheet sands are mainly from waterway deposits.

Affected by sedimentary environment, the sand bodies in the nearshore subaqueous distributary channel are 20–30 m thick, and the infralittoral waterway sand bodies are 10–20 m thick. In the northwest, the oil sand is outwedging, while in the southeast lies the oil–water boundary. Due to rapid deposition, it is coarse in lithology and wide in thickness.

(c) The reservoir is thick with medium depth and concentrated reserves

Affected by sedimentary environment, the reservoir is thick. According to the statistics of the 27 wells of H_3IV3^1, the effective drilled thickness is 315.3 m, with an average 11.6 m for the single well. There is only one well with effective thickness of less than 3 m, accounting for 3.7 %; four wells with effective thickness of 3–5 m, accounting for 14.8 %; nine wells with effective thickness of 5–10 m, accounting for 33.3 %; and 13 wells with effective thickness of more than 10 m, accounting for 48.1 %.

According to the latest geological research, the reservoir is subdivided into seven flow units, and the inner barriers of the reservoir are relatively stable. The depths of the reservoir are 2214–2275 m, and the length of the oil-bearing section is 61 m.

(d) Moderate physical properties with serious heterogeneity

According to the statistics of rock core analysis of H_3IV3^1, the reservoir is dominated by lithic feldspar quartz brecciated sandstone and pebbly sandstone, with an average porosity of 15.3 %, an average permeability of $168 \times 10^{-3}\ \mu m^2$, and oil saturation from 60 to 75 %. It has serious internal heterogeneity, with permeability variation coefficient 0.85, onrush coefficient 2.7, and permeability differential 15.6. The barrier is stable, mainly composed of muddy siltstone and mudstone, with a thickness of less than 1.0 m.

Data analysis of the petrographic thin section shows that the reservoir is mainly lithic feldspar quartz brecciated and pebbly sandstone. Particle rounding is from subangular to subround, with medium particle sorting coefficient from 1.5 to 2.1 and particle size median 0.1–0.5 mm. Binding materials are mainly gray and muddy substances in pore type.

(e) Major problems in oilfield development

The reservoir has been developed since 1983, adopting an irregular five-spot injection-production well pattern. It has undergone four development stages: natural energy production stage, water flooding production stage, comprehensive adjustment stage, and improvement of partial well pattern stage. After over 20 years' development, its water cut reaches over 92 %, but the degree of recovery reserve is only 30 %. Major development problems include imperfect injection-production well pattern, too many oil wells of one-directional injection effect, low water drive control, serious flooding in thick reservoir with differential longitudinal distribution and interlayer differences influenced by sedimentary rhythm, low degree of reserve recovery, high water cut, and low energy.

2. Overview of Anpeng reservoir H_3IV2^{1-3}

Exploratory well Bi-73 in the reservoir H_3IV2^{1-3} in Anpeng Oilfield had oil production testing and starting up in December 1985. In January 1986, irregular five-spot injection-production well pattern was used for oil production, with a gradual increase in production wells. In September 1987, water was injected starting from well Bi-116. After the improvement of productivity construction from 1986 to 1992, there was an adjustment based on problems in the development in 1993, which was completed in 1995 and followed by partial improvement and adjustment from 1996 on.

In November 2003, the reservoir H_3IV2^{1-3} in Anpeng Oilfield had 26 oil wells and 12 producing wells, with a daily oil production of 49.7 t, an annual oil production of 1.64×10^4 t, a daily average oil production per well of 4.14 t, an annual oil production rate of 0.58 %, an oil degree of reserve recovery of 27.74 %, and an average water cut of 93 %. There were 15 water wells, 14 injecting wells, with a daily injection of 717.4 m^3, a cumulative injection of 339.5×10^4 m^3, an injection-production well ratio of 1:0.86, a cumulative injection-production ratio of 1.03, underground storage water of 19.53×10^4 t, and well spacing density of 11.72 wells/km^3. With the development of the reservoir, there appeared problems like imperfect injection-production system and a quick water cut increasing rate, showing the injection-production incompatibility of the whole reservoir, which resulted in a low degree of reserve recovery, high water cut, low formation pressure, etc.

6.1.2 Optimization Analysis of the Vector Well Pattern in Zhao'ao Oilfield

Based on the practical field development and reservoir engineering analysis, the vector well pattern theory is applied in the optimization of well pattern in Zhao'ao Oilfield. According to the vector well deployment methods, a virtual development research is conducted to acquire the best well pattern and water flooding directions, based on the geological model of Zhao'ao Oilfield. On the basis of the reservoir engineering analysis of the well pattern adaptability and appropriate well pattern density of H_3IV3^1 in Zhao'ao Oilfield and H_3IV2^{1-3} in Anpeng area in Zhao'ao Oilfield, a reasonable well pattern for the whole oilfield is put forward after numerical simulation analysis.

1. Fictitious development simulation of H_3IV3^1 in Zhao'ao Oilfield

The reservoir engineering analysis and calculation show that the reasonable well spacing of H_3IV3^1 in Zhao'ao Oilfield is about 250 m. Because it is closely related to oil price, there are different well spacings. A reasonable well spacing in practical arrangement of well patterns should be determined by the corresponding technology policy.

The following discussion focuses on how to choose a reasonable well pattern with a definite well spacing. As clarified above, the vector well pattern combined with different micro-facies analysis will be applied in the whole oilfield. Due to the fact that the five-spot or inverted nine-spot injection well patterns are adopted in H_3IV3^1 in Zhao'ao Oilfield and that their directions are either in accordance with the provenance direction or at an angle of 45° (parallel to the direction of the edge water), numerical simulation calculation is applied in that area. Virtual development calculation is mainly applied to new well patterns, in light of its geological model, to investigate into the current development effects, aiming to take it as a basis for later adjustment in this reservoir by comparing it with the former well patterns in developed oilfield to analyze their advantages and disadvantages.

Analysis and calculation show that inverted nine-spot well pattern is better (see Figs. 6.1, and 6.2). In principle, the vector well pattern should be deployed.

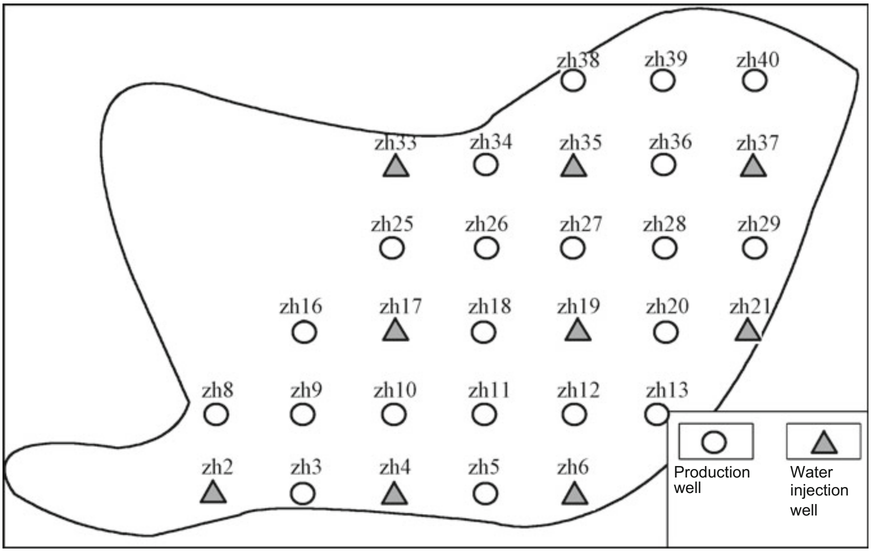


Fig. 6.1 Inverted nine-spot well rows parallel to contours

Case 1: Maintain the current well pattern and the current production mode. Oil wells of high water cut should have a fixed oil production, which is dependent on the water cut of each well.

Case 2: From the production year on, oil wells and water wells should be arranged parallel to the edge of the edge water or depth contours, forming reverse nine-point well pattern (See Fig. 6.1). Specifically, to be arranged are 21 oil wells: Zhao-2, Zhao-4, Zhao-6, Zhao-7, Zhao-8, Zhao-9, Zhao-10, Zhao-12, Zhao-14, Zhao-15, Zhao-16, Zhao-17, Zhao-18, Zhao-19, Zhao-20, Zhao-22, Zhao-24, Zhao-27, Zhao-28, Zhao-29, and Zhao-31; and nine injection wells: Zhao-1, Zhao-3, Zhao-5, Zhao-11, Zhao-13, Zhao-21, Zhao-23, Zhao-30, and Zhao-32. When the water cut reaches 30 %, oil wells Zhao-8, Zhao-18, Zhao-28, Zhao-29, Zhao-6, Zhao-16, and Zhao-27 should be converted to injection well, hence forming row well pattern. At this point, the water drive direction is at an angle of 45° with the principal permeability direction. The production for single oil well is determined according to the actual production statistics, taking the annual production of ten oil wells for average.

Case 3: From the production year on, oil wells and water wells should be arranged into reverse nine-point well pattern, in which the seepage direction should be accorded with the provenance direction (see Fig. 6.2). Specifically, to be deployed are 21 production wells: Zhao-3, Zhao-5, Zhao-8, Zhao-9, Zhao-10, Zhao-11, Zhao-12, Zhao-13, Zhao-16, Zhao-18, Zhao-20, Zhao-25, Zhao-16, Zhao-27, Zhao-28, Zhao-29, Zhao-34, Zhao-36, Zhao-38, Zhao-39, and Zhao-40; and nine injection wells: Zhao-2, Zhao-4, Zhao-6, Zhao-17, Zhao-19, Zhao-21, Zhao-33,

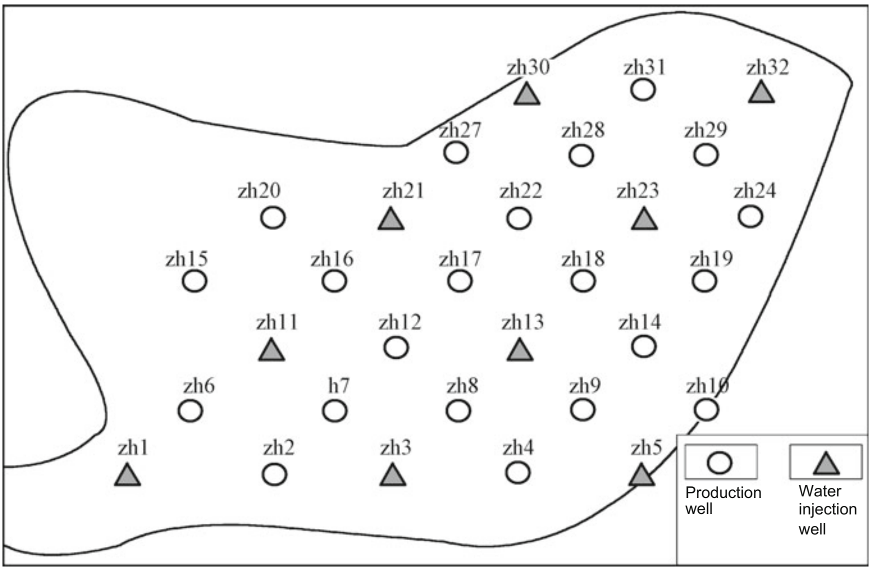


Fig. 6.2 Inverted nine-spot well rows parallel to provenance direction

Zhao-35, and Zhao-37. When the water cut reaches 30 %, oil wells Zhao-3, Zhao-5, Zhao-16, Zhao-18, Zhao-20, Zhao-34, and Zhao-36 should be converted to injection well, hence forming the row well pattern. The production for the single oil well is calculated according to the practical production statistics, the annual production of ten wells taken for average.

The development indexes of different schemes is obtained by numerical simulation analysis and calculation, as shown in Figs. 6.3, 6.4 and 6.5. By comparing the above fictitious cases and the practical oilfield development, the recovery of Case 2 can reach 41 %, 8 % higher than the status quo of 33 % only. From the beginning to the present with a 10-year forecast, Case 2 would produce 14.49×10^4 t more oil than the actual practice. The present well density has reached 13 wells/km^2, while that of Case 2 is 11.2 wells/km^2. The fictitious case is significantly better than the present well pattern; therefore, later adjustment of this reservoir should be based on the present well pattern, but be close to Case 2, thus changing the water drive direction and greatly improving the water drive effect.

2. Fictitious development simulation of reservoir H_3IV2^{1-3} in Anpeng Oilfield

As for Anpeng Oilfield, two different fictitious cases are designed to optimize the well pattern, in comparison with the practical development.

Case 1: To be deployed are 35 wells, of which there are 26 production wells and nine injection wells, with a well spacing of 300 m. The well rows, running from east to west, are perpendicular to the provenance direction, that is, the water flooding direction is accorded with the provenance direction, forming an reverse nine-point well pattern.
Case 2: To be deployed are 35 wells, of which there are 25 production wells and 10 injection wells, with a well spacing of 310 m. The well rows, parallel to the edge of the edge water or depth contours, form a reverse nine-point injection well pattern.

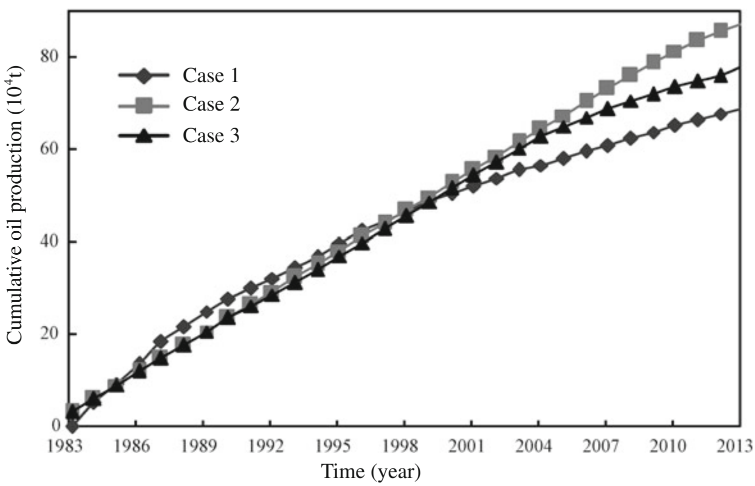


Fig. 6.3 Comparison of cumulative oil production in different cases

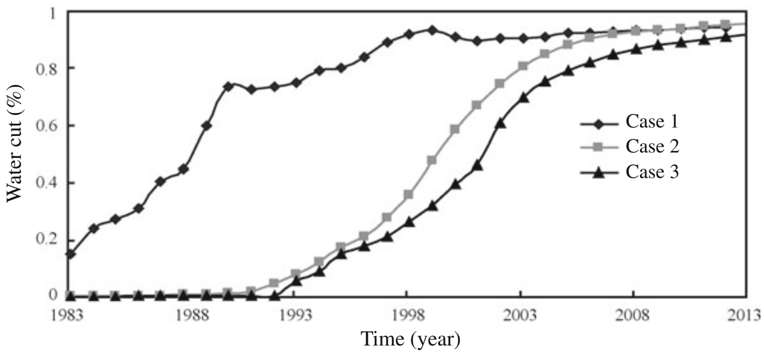


Fig. 6.4 Comparison of water cut in different cases

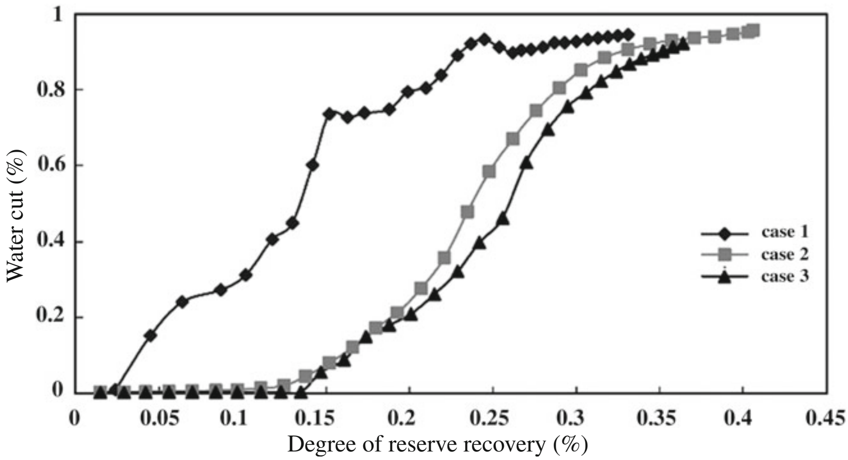


Fig. 6.5 Relation between degree of reserve recovery and water cut in different cases

Production data in the development are as follows: New wells are opened with fixed oil production for a year; at the beginning of the next year, injection wells begin waterflooding and start up oil wells with fixed fluid production for three years continuously; at the beginning of the fifth year, turn all the oil wells along the row of injection wells into injection wells and carry on increasing fluid production up to the present.

Fictitious production data are customized according to the following data: Oil wells An-2, An-6, An-7, An-10, An-14, An-20, An-25, An-45, An- 51, and Bi-119 are, respectively, assigned with the maximum values, which are fixed oil production of 16 m^3 in the first year, fixed fluid production of 35 m^3 in the second year, and increased fluid production of 45 m^3 in the fifth year, according to the average oil production of 16.3 m^3 in the first year, and the average fluid production of 35.8 and 44.6 m^3 in the second and the fifth years, respectively.

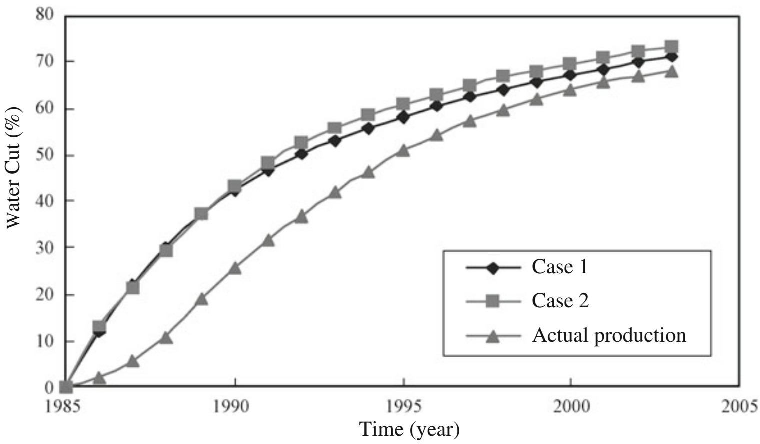


Fig. 6.6 Comparison of water cut in different cases

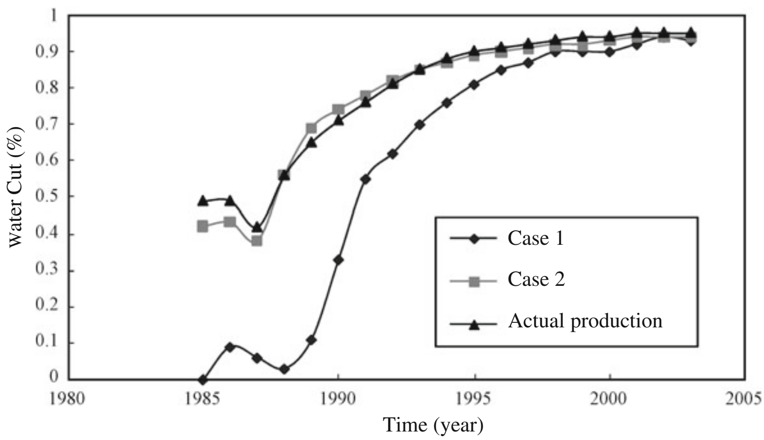


Fig. 6.7 Comparison of cumulative oil production in different cases

In numerical calculation, the principles controlling production data are as follows: Fixed oil production or fixed fluid production is preferred to fixed pressure production, which is applicable when the oil production is under the expected amount.

Figures 6.6, 6.7, and 6.8 describe the comparison of practical production and fictitious Case 1 and Case 2 in terms of cumulative oil production, recovery, and water cut, which show that Case 1 and Case 2 are better than the practical case, with an increase of 3.01×10^4 t and 5.17×10^4 t, respectively. Additionally, the corresponding water cut is basically the same when the recovery is the same in high water cut period.

The present well spacing density has reached 11.7 wells/km^2, while that of Cases 2 and 3 is 10 wells/km^2. The well pattern of the fictitious cases is significantly better than the present one; therefore, later adjustment of this reservoir should

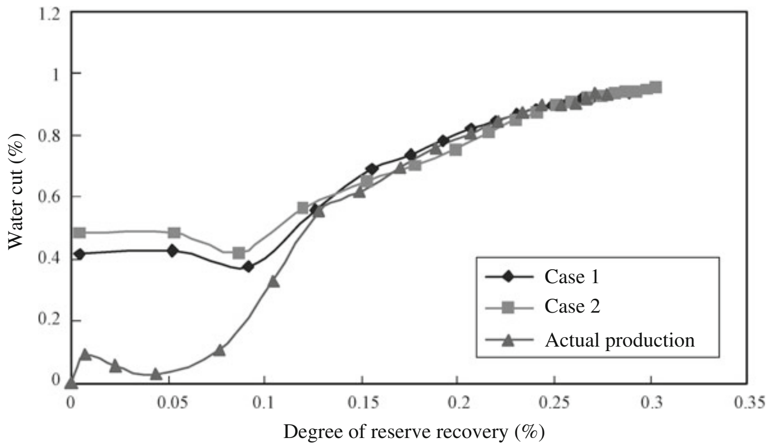


Fig. 6.8 Comparison of water cut in different cases

be based on the present well pattern, but be close to Case 3, thus changing the water drive direction and greatly improving the water drive effect.

Through simulated calculation and fictitious development analysis, Zhao'ao Oilfield should adopt reverse nine-point well pattern parallel to the edge of the edge water or depth contours. When the water cut reaches 30 %, it should be changed into the row well pattern. Later, it can be converted into non-isometric five-point well pattern.

6.1.3 Adjustment Analysis of the Vector Well Pattern in Zhao'ao Oilfield

Based on the above reservoir engineering and numerical simulation research, in light of the geological characteristics of H_3IV3^1 in Zhao'ao Oilfield and H_3IV2^{1-3} in Anpeng Oilfield, different adjustment cases are put forward according to the adjustment methods and principles for the vector well pattern. The best well pattern adjustment case is determined by a comparative analysis of the dynamic production forecast.

1. Adjustment projects of H_3IV3^1 in Zhao'ao Oilfield

On the basis of sufficient history match, six different adjustment cases are put forward according to the present well pattern, geological research findings, and remaining oil distribution law. The cases take into consideration the main factors such as maintaining the present well pattern and production mode, reperforating for water shutoff, heavy repair, water drive transfer, sidetracking, and drilling new wells, aiming to change water drive direction to improve oilfield development effect and to increase recovery. Additionally, production forecast of the six adjustment cases is carried on for ten years.

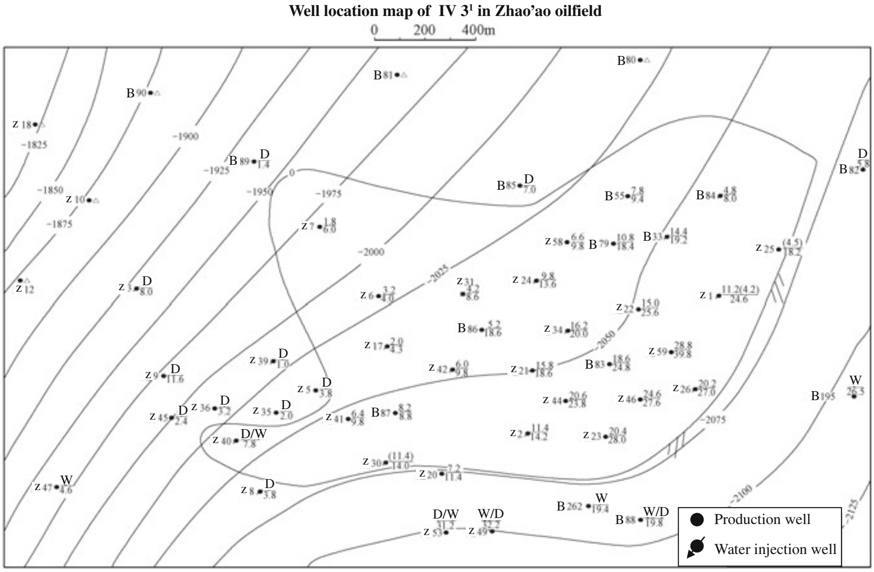


Fig. 6.9 Relation between degree of reserve recovery and water cut in different cases

Case 1: Maintain the status quo. That is, keep the present well pattern to maintain the present production. Set a fixed oil production for high water cut wells, which is determined by the water cut of each well, as shown in Fig. 6.9.

Case 2: Deploy new production wells Zhao-64, Zhao-68, Zhao-70, Zhao-72, and Zhao-73 and water well Zhao-67 and reinject Zhao-44. Due to their relatively low oil production and very high water cut, Zhao-20 and Zhao-23 are converted to form a row of injection wells composed of Zhao-30, Zhao-20, Zhao-2, Zhao-23, and Zhao-26 in the south of H_3IV3^1. Such a well pattern can increase the sweep area because its waterline direction is accorded with the provenance direction, and H_3IV3^1 is mainly composed of river sedimentary micro-facies. Similarly, Zhao-22 is converted to form a row of injection wells composed of Zhao-17, Zhao-42, Zhao-34, Zhao-22, and Zhao-1, with its water drive direction basically parallel to the provenance direction and main permeability direction, while contrary to the moving direction of the crude oil.

Case 3: Deploy new production wells Zhao-64, Zhao-68, Zhao-70, Zhao-72, and Zhao-73 and water well Zhao-67 and convert Bi-83 into an injection well, making the water drive direction basically perpendicular to the main seeping direction. Deploy a step-out information well Zhao-68 by the thicker sand of the northern edge of the small layer of oil sand in H_3IV3^1; deploy Zhao-69 near Bi-79, aiming to improve the reserve control of the dip pinchout in the small layer of H_3IV3^1 to improve the injection-production well pattern, understand the water-out behavior of the thick oil layer, dig for inner layer potential, and provide a basis for the breakdown and adjustment of the thick oil layer.

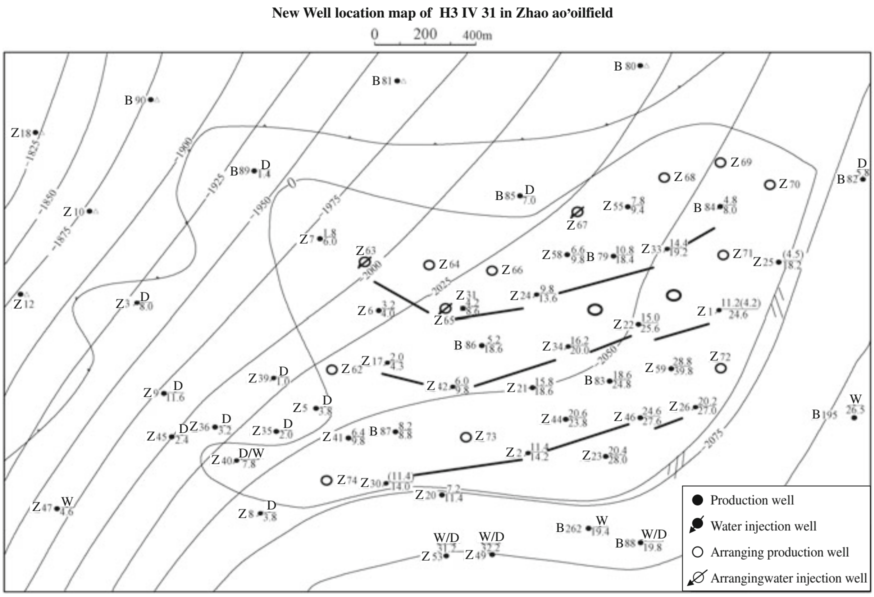


Fig. 6.10 New well location map of H_3IV3^1 in Zhao'ao Oilfield

Case 4: Deploy 12 new wells including nine oil production wells Zhao-62, Zhao-64, Zhao-66, Zhao-68, Zhao-69, Zhao-70, Zhao-71, Zhao-72, and Zhao-74 and three injection wells Zhao-63, Zhao-65, and Zhao-67 and convert Bi-84 and Zhao-44 into injection wells. After some time, adjust to form a row of water drive basically parallel to the provenance direction and main seeping direction, but contrary to the moving direction of the crude oil. It not only adjusts the water drive direction and improves the well pattern, but also increases the water swept volume and displacement efficiency.
Case 5: On the basis of Case 4, deploy two more new oil production wells Zhao-75 and Zhao-76 (see Fig. 6.10).
Case 6: On the basis of Case 3, deploy two new oil production wells Zhao-62 and Zhao-74, two injection wells Zhao-78 and Zhao-79, and convert oil well Bi-84 into an injection well.
The development indices of each case for each year can be predicted by calculation as shown in Figs. 6.11, 6.12, and 6.13.

By analyzing and comparing the development indices of the six cases, it can be seen that the oil production in Case 1 decreases quickly to a final recovery of 33.7 % because no measure has been taken, while Case 4 and Case 5 have better development effects than the other cases, with comprehensive measures and the drilling of adjustment wells. Up to December 2013, the cumulative oil production in Case 4 and Case 5 is 78.21×10^4 t and 79.67×10^4 t, respectively, boasting a

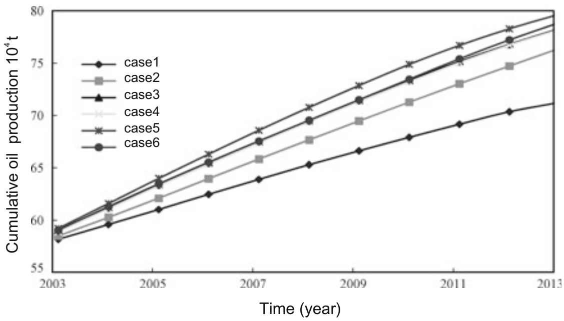


Fig. 6.11 Comparison of cumulative oil production in different cases in H_3IV3^1 in Zhao'ao Oilfield

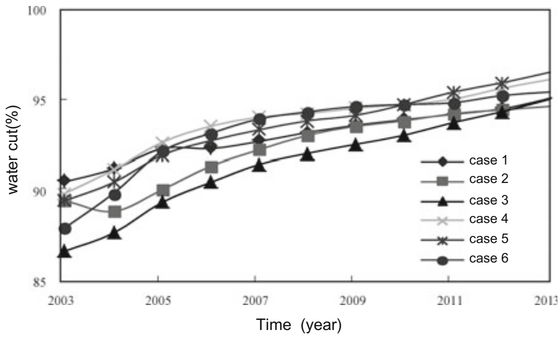


Fig. 6.12 Comparison of water cut in different cases in H_3IV3^1 in Zhao'ao Oilfield

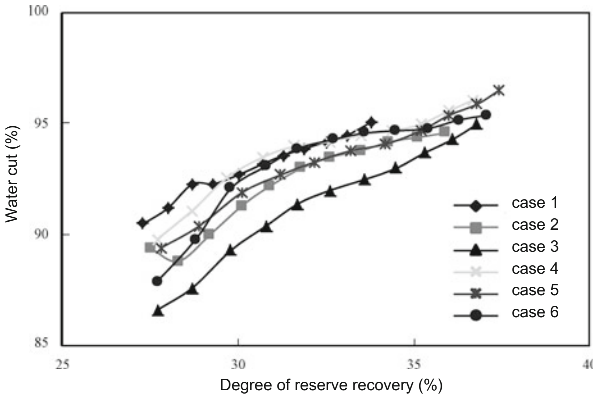


Fig. 6.13 Relation of water cut and degree of reserve recovery in different cases in H_3IV3^1 in Zhao'ao Oilfield

recovery of 36.7 and 37.4 %, respectively. In ten years, cumulative oil production in Case 4 reaches 19.32×10^4 t, 6.23×10^4 t more than that in Case 1, and cumulative oil production in Case 5 reaches 20.45×10^4 t, 7.36×10^4 t more than that in Case 1. It can be seen that applied adjustment measures significantly increase oil production. Case 5 is better than Case 4 with more oil production, but at the cost of two more production wells.

Comprehensive comparison and analysis show that Case 4 that adjusts the well pattern with vector optimization is the best case.

2. Adjustment projects of H_3IV2^{1-3} in Anpeng Oilfield

On the basis of sufficient history match, three different adjustment cases for H_3IV2^{1-3} in Anpeng Oilfield are put forward in light of the vector well pattern principles, present well patterns, geological research results, and the remaining oil distribution law. The cases take into consideration the main factors such as maintaining the present well pattern and production status, adding perforations, water shutoff, big repair, sidetracking, and drilling new wells, aiming to change fluid flowing direction to improve oilfield development effect and to increase recovery. Additionally, production forecast of the three development adjustment cases is carried on for eight years.

Case 1: Maintain the status quo, i.e., keep the present well pattern to maintain the present production. Determined by the water cut of each well, a fixed oil production is set for wells of high water cut, as shown in Fig. 6.14.
Case 2: On the basis of the present well pattern, reperforate the present water wells, sidetrack four wells, drill three new wells, and reopen one well, as shown in Fig. 6.15. The adjustment is to drill new wells and convert wells to make the water drive direction parallel with the contour, which is accorded with the optimized results mentioned in the former sections. Specific well deployment is shown in Fig. 6.15.

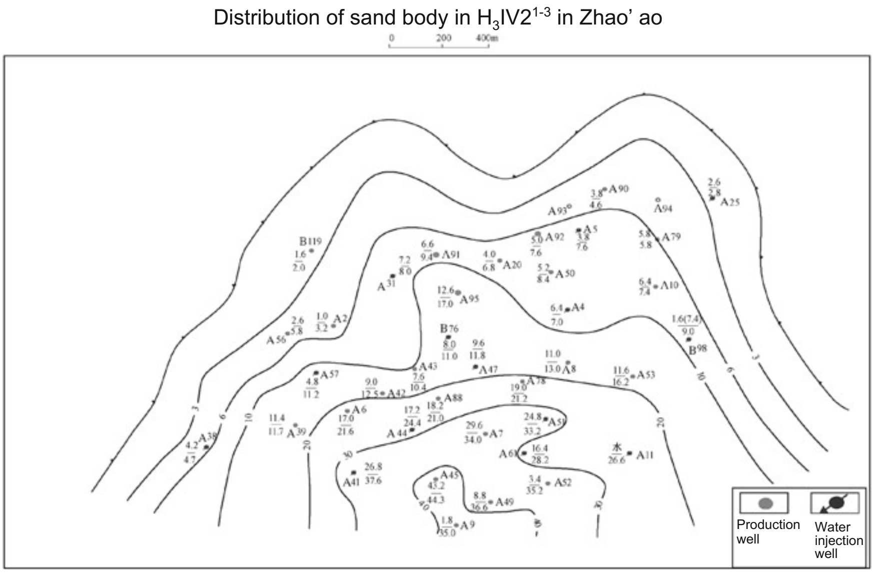


Fig. 6.14 Distribution of sand body in H_3IV2^{1-3} in Anpeng Oilfield

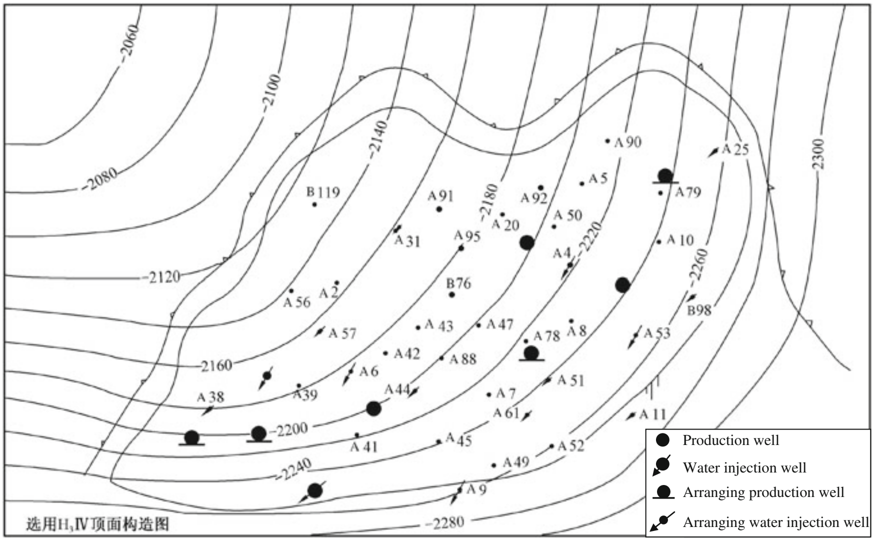


Fig. 6.15 Well deployment of the small layer H_3IV2^{1-3} in Anpeng Oilfield

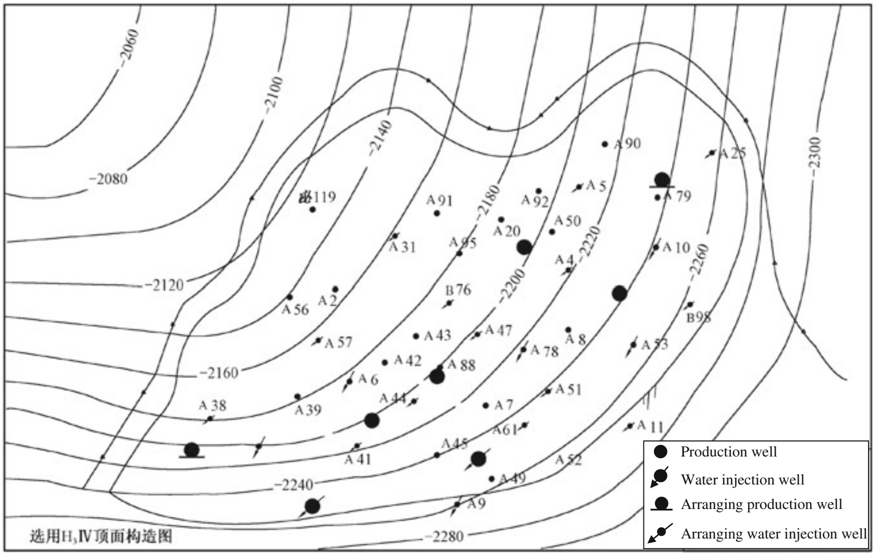


Fig. 6.16 Well deployment of the small layer H_3IV2^{1-3} in Anpeng Oilfield

Case 3: On the basis of the present well pattern, reperforate the present water wells, sidetrack two wells, drill four new wells, and reopen three wells. The adjustment is to drill new wells and convert wells to make the water drive direction perpendicular to the contour. Specific well deployment is shown in Fig. 6.16.

The same indices in different cases are compared in Table 6.1 and Figs. 6.17, 6.18, and 6.19.

By analyzing and comparing the development indices of the three cases, it shows that oil production in Case 1 decreases quickly to a low final recovery of 30.2 % as no measure has been taken, while Case 3 has a better development effect than Case 1 and Case 2, with comprehensive measures and the drilling of adjustment wells. By December 2011, the cumulative oil production in Case 3 had reached 79.7×10^4 t. In ten years, cumulative oil production in Case 3 reached 11.46×10^4 t in ten years, 5.4×10^4 t more than that in Case 1. It can be seen that comprehensive measures such as adding perforations, extracting fluid, and drilling new wells significantly increase the oil production.

Comprehensive comparison and analysis show that Case 2 that adjusts well patterns with vector optimization is the best case.

6.2 Optimal Design and Application of the Vector Well Pattern in Oil Group VI of Shuanghe Oilfield

6.2.1 *Overview of Oil Group VI of Shuanghe Oilfield*

Oil group VI of Jianghe district in Shuanghe Oilfield has a southeast–northwest tilting nose structure, with dip angles changing from about 5° to 10°. To its southwest are two oblique normal faults of different directions. It has an oil-bearing area of 7.93 km^2, a geological reserve of 681×10^4 t in depth from 1810.0 to 2020.0 m. The calibration degree of reserve recovery is 48.4 %, with a recoverable reserve of 329.85 t. Serious interlayer anisotropy and good reservoir petrophysics are its main characteristics.

Shuanghe Oilfield, located on the nose-like structure of Shuanghe Town to the southwest of Biyang sag, is currently the best enrichment zone in this area. The third unit of Hetaoyuan Formation of the third Lower Series is the major reservoir, which is divided into nine oil groups from top to bottom. Groups I–IV are mainly located in Shuanghe Oilfield, while groups V–IX are mainly in Jianghe Oilfield. In light of the reservoir characteristics and development, the reservoir bed is fan delta glutenite that quickly deposited from near-provenance steep slope, with sand body spreading like a fan and forming updip pinchout in the northwest. The buried depths of the reservoir range from 1200 to 2600 m, while it is about 1200 m thick with significant petrophysical variation and serious interlayer anisotropy. Oil group VI of the third unit of Hetaoyuan Formation (H_3VI), the target of this research, is divided into 17 small layers.

Regarding the structural characteristics, the third unit of Hetaoyuan Formation in Shuanghe Oilfield is relatively simple. It has an overall construction resembling a southeast–northwest tilting nose, with axial variations in different parts. As for the faults' development, the whole construction has 18 faults with various sizes, with a

Table 6.1 Comparison of indices in the adjustment cases

Time	Case 1			Case 2			Case 3		
	Cumulative oil (10^4 t)	Degree of reserve recovery (%)	Water cut (%)	Cumulative oil production (10^4 t)	Degree of reserve recovery (%)	Water cut	Cumulative oil production (10^4 t)	Degree of reserve recovery (%)	Water cut (%)
2003	67.25	0.273	93.66	67.25	0.273	93.66	67.25	0.273	93.64
2004	68.15	0.277	93.87	69.29	0.282	92.90	68.90	0.280	93.12
2005	69.00	0.280	94.47	71.25	0.290	93.98	70.51	0.287	94.17
2006	69.81	0.284	94.88	72.78	0.296	94.24	71.75	0.292	94.11
2007	70.60	0.287	95.23	74.14	0.301	95.06	72.86	0.296	94.98
2008	71.35	0.290	95.54	75.39	0.306	95.60	73.90	0.300	95.50
2009	72.07	0.293	95.81	76.53	0.311	96.01	74.87	0.304	95.88
2010	72.75	0.296	96.04	77.58	0.315	96.34	75.77	0.308	96.19
2011	73.40	0.298	96.24	78.57	0.319	96.59	76.62	0.311	96.45

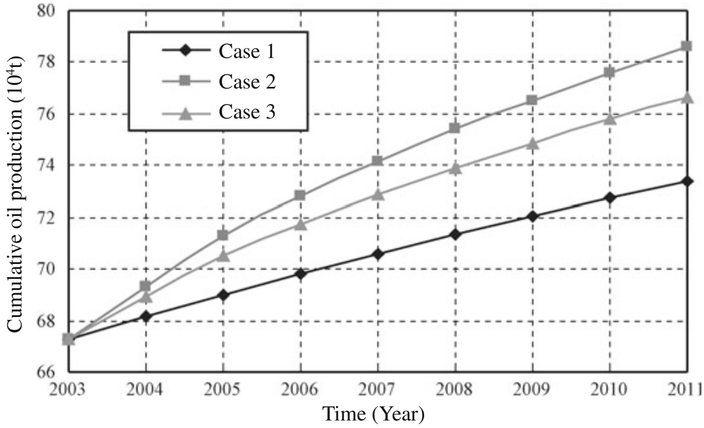


Fig. 6.17 Comparison of cumulative oil production in different cases

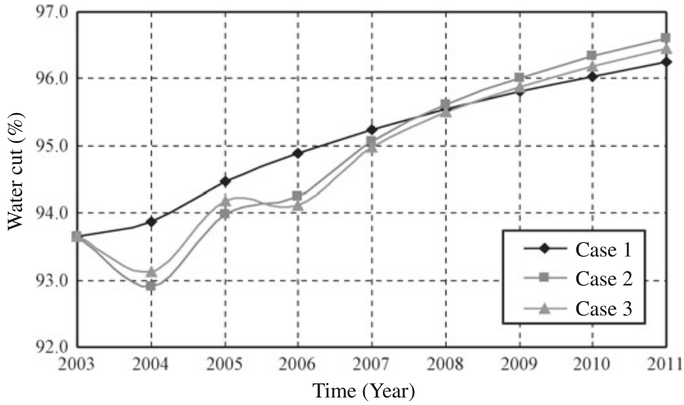


Fig. 6.18 Comparison of water cut in different cases

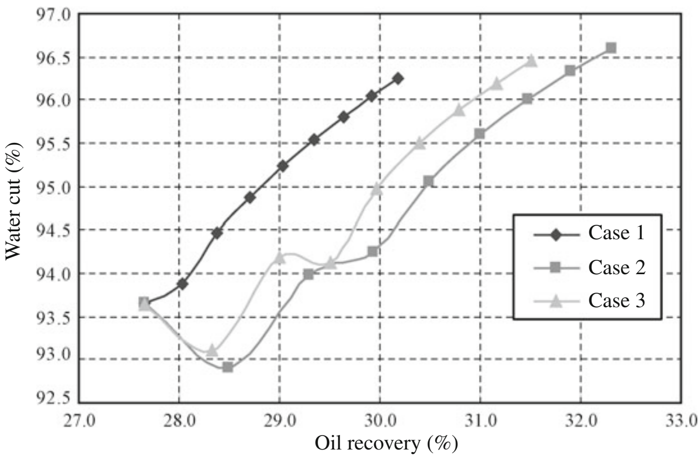


Fig. 6.19 Relation between degree of reserve recovery and water cut in different cases

general northeast–southwest extension, the maximum length of about 2250 m, and the minimum length of 400 m. In terms of the faults' obliqueness and characters, it is mainly composed of northwest-leaning or southward-leaning normal faults, respectively, at angles of 26° to 52° and 45° to 80°.

As for the trap types, developed traps in the third unit of Hetaoyuan Formation in Shuanghe Oilfield mainly include four types, which are sandstone updip pinchout traps, fault-up dip pinchout traps, broken nose traps, and lens sandstone traps.

It was put into development and production in 1978, and water injection has been applied since November the same year. All-around adjustment has been carried out since 1982. It consists of the comprehensive adjustment of the reservoir subdivision, the first and second refinement adjustment of the well pattern, and the significant adjustment including the partial subdivision and improvement in the well pattern after the second refinement adjustment. More measures such as well pattern adjustment, optimization of injection and production, conversion of old producers into injectors, renewal, big repair, and sidetracking have been taken to optimize and reconstruct the injection-production system, thus ensuring the high-speed and high-efficiency development in the period of especially high water cut. In recent years, the development effect is not satisfactory due to the factors that the whole reservoir has suffered overall water breakthrough with the extension of production time, that more low-efficiency wells have to be closed or returned with the continuous increase of water cut, that serious casing damage makes the injection-production system incomplete, and that poor adaptability of the recovery techniques fails to suit the reservoir characteristics.

By November 2003, H_3VI in Shuanghe Oilfield has built 114 oil wells and water wells, with a well density of 14.38 wells/km^2. In the 77 oil wells, there are 45 flowing wells, with a flowing well rate of 58 %. The daily fluid production is 1600 t, daily oil production is 91 t, average daily fluid production per well is 53.3 t, average daily production per well is 2.0 t, composite water cut is 94.3 %, and cumulative oil production is 282.955×10^4 t. In the 37 water wells, there are 28 flowing wells, with a flowing well rate of 75.6 %. The daily water injection is 1922 m^3, cumulative water injection is 1582.55×10^4 m^3, injector producer ratio is 1:2.9. The degree of reserve recovery is 40.8 %, composite decline rate is 11.64 %, natural decline rate is 9.3 %, and cumulative injection-production ratio is 0.88. It shows that the reservoir has entered a development period of high water cut and high degree of reserve recovery.

6.2.2 Reservoir Characteristics and Directivity

The sediment provenance of H_3OVI in Shuanghe Oilfield mainly comes from Pingshi in the south of Biyang sag. The fan delta deposit, formed in the steep slope of the sag by a large number of materials carried by the river, can be subdivided into two subfacies of fan delta front and front fan delta, micro-facies of fan delta front underwater distributary channel, interchannel depressions, sheetflood sheet sand, estuarine sand bar,

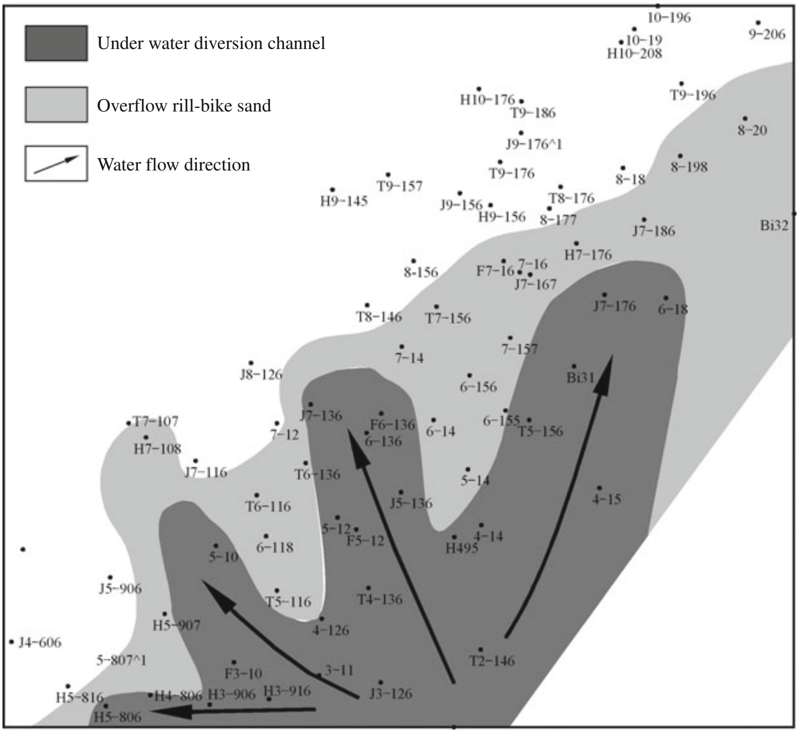


Fig. 6.20 SSC4 deposit micro-facies of short-term cycle sequence in H_3OVI, Shuanghe Oilfield

etc. Major micro-facies are underwater distributary channel and sheetflood sheet sand, as shown in Fig. 6.20. The interlayer porosity of each layer is not of obvious anisotropy, and the interlayer permeability is of moderate-to-strong anisotropy.

Characteristics of provenance, main seepage, and sand body distribution: From the perspective of regional sedimentary environment, the provenance of H_3OVI in Shuanghe Oilfield is from the south by east, and the main sand body distribution is along the provenance direction, with good sand connectivity in this direction. According to the analysis of the historical characteristics of water injection, the water breakthrough direction is mainly southeast to northwest and is accorded with the direction of the side water. With the increase of development time and well pattern adjustment, the direction of the water breakthrough is indefinite. The dynamic of the water breakthrough in oil well confirms the influence of the reservoir sedimentation law on the water breakthrough direction.

Its reservoir distribution is characterized by perpendicularly multiple stratified reservoir and bad sand body connectivity. Geological analysis shows that (1) sand body connectivity coefficient in the target layer of Shuanghe Oilfield is less than 0.5, reflecting that in Shuanghe Oilfield, each medium-term base-level cycles in sandstone thickness varies significantly, with bad connectivity; (2) as for the distribution coefficient, that of the sand in Shuanghe Oilfield is much less than 1, reflecting that the oil-bearing area of each layer is significantly smaller than that of the reservoir; and (3) in the sand layers of Shuanghe Oilfield, the effective thickness coefficient and the variation coefficient vary significantly, reflecting the great difference in the thickness and effective thickness and strong plane heterogeneity.

The direction of reservoir is mainly expressed in that the directions of the provenance and main seepage are mainly south–west and that of the edge water incursion is southeast–northwest.

6.2.3 Vector Well Pattern Adjustment Analysis

According to the dynamic analysis of the reservoir and numerical simulation research results, the potential and geological characteristics, remaining oil distribution law, the present well pattern, and three different adjustment cases for oil group VI of Jianghe district in Shuanghe Oilfield are put forward on the basis of sufficient history match and the vector well pattern principles. Additionally, production forecast research is carried on, and forecasting results are compared.

On the basis of sufficient history match, the adjustment cases, with a forecast of eight years, include maintaining the present well pattern and recovery status, reperforating, extracting fluid, sidetracking, and drilling new wells.

The major measures are as follows:

(a) Reperforating: After checking, reperforate the layers that are not opened but with potential.
(b) Extracting fluid: It is used for the production wells with fairly good production, sufficient feed flow, favorable injection-production relation, and fair potential after remaining oil distribution analysis.
(c) Sidetracking: Adjust the well pattern on the basis of former water wells of high water cut or shutoff wells when a certain output exists before the oil well is shut off, or quite a lot of remaining oil exists near the well, or it is inconvenient to deploy new wells.
(d) Drilling new wells: New wells can be deployed in areas of rich remaining oil, usually moderately or weakly flooded areas with certain economical and utilizable reserves.

Case 1: Maintain the status quo. That is, keep the present well pattern to maintain the present production. Wells of high water cut set a fixed fluid production, which is determined by the water cut of each well. The well pattern is shown in Fig. 6.11.
Case 2: On the basis of the present well pattern, reperforate two wells, drill five new wells and sidetrack two wells, and convert five oil wells into injection wells (work specified in Tables 6.2, 6.3, and 6.4). The production of new wells and sidetracked wells is firstly based on a fixed oil production. When the oil production decreases later with a fairly high water cut, the technique of extracting fluid with 1.2 times of daily fluid production should be used for the production, while injection wells maintain injection with an injection-production balance. The principle for well

Table 6.2 Measures in Case 2 for oil group VI of Jianghe district

Well type	Measure	No. of wells	Well name and others
Oil well	Sidetracking	1	New 9-4
	Reperforating	2	T6.116, 4-14
	New wells	5	New 9-2, New 9-6, New 9-7, New 9-8, New 9-10
	Subtotal	8	
Water well	Conversion	4	J6.806, T8-176, J7-176, 6.14
	Subtotal	4	

Table 6.3 List of new oil and water wells in Case 2

Well name	Well type	Well location	Horizon for simulated perforating
New 9-2	New oil well	T6.917N100m	5.6.17.20.21.23.24
New 9-4	Sidetracked well	J10-176N150m	11.20.21
New 9-6	New oil well	Mi-47W150m	1.5.6.7.8.11.15.20.23
New 9-7	New oil well	T7-156NW50m	5.6.7.8.10.20
New 9-8	New oil well	H7-176SE150m	1.5.6.7.8.9.10
New 9-10	New oil well	3-13SW100m	1.3.4.5.6.7

Table 6.4 Measures of oil and water wells in Case 2

Well name	Measure	Horizon (for simulated reperforating)
J6.806	Oil well to injection well	5.8.9.10.21
T8-176	Oil well to injection well	1.6.7.10.11.12.15.20.22
J7-176	Oil well to injection well	1.5.6.7.11.12
6.14	Oil well to injection well	1.5.6.7.8.9.10.11.12.13.20
T6.116	Reperforating of oil well	1.5.20
4-14	Reperforating of oil well	4.5.6.7

pattern adjustment is to ensure that the injection wells are basically perpendicular to the provenance direction, while water drive direction is accorded with the provenance direction. The well pattern is shown in Fig. 6.12.

Case 3: On the basis of Case 2, sidetrack one more well, drill four more new wells, and convert two oil wells. The production of new wells and sidetracked wells is first based on a fixed oil production. When the oil production decreases later with a fairly high water cut, the production should be based on a fixed fluid production, while injection wells maintain injection with a basic injection-production balance. The designed maximum fluid production is 100 m^3/d. The measures are specified in Tables 6.5, 6.6, and 6.7. The well pattern is shown in Fig. 6.13.

Based on the adjustment measures of the cases, numerical simulation is carried out each year to forecast the development indices of the cases. Comparisons of the same index of different cases are shown in Figs. 6.21, 6.22, and 6.23.

Table 6.5 Measures in Case 3 in Shuanghe Oilfield

Well type	Measure	No. of wells	Well name and others
oil well	Sidetracking	2	New 9-4, New 9-5
	Reperforating	2	T6.116, 4-14
	New wells	9	New 9-2, New 9-6, New 9-7, New 9-8, New 9-10
	Subtotal	13	New 9-1, New 9-2, New 9-3, New 9-6, New 9-7, New 9-8, New 9-9, New 9-10, New 9-11
Water well	New wells	3	New 9-12, New 9-13, New 9-14
	Conversion	6	J6.806, H7-108, H6.106, T8-176, J7-176, 6.14
	Subtotal	9	

Table 6.6 List of new oil and water wells in Case 3

Well name	Well type	Well location	Horizon for simulated perforating
New 9-1	New oil well	H5-816SE200m	5.10.13.17.20.21.24
New 9-2	New oil well	T6.917N100m	5.6.17.20.21.23.24
New 9-3	New oil well	H7-116NW150m	5.8.10.20.21.23
New 9-4	Sidetracked well	J10-176N150m	11.20.21
New 9-5	Sidetracked well	T9-186NW150m	11.20.21
New 9-6	New oil well	Mi-47W150m	1.5.6.7.8.11.15.20.23
New 9-7	New oil well	T7-156NW50m	5.6.7.8.10.20
New 9-8	New oil well	H7-176SE150m	1.5.6.7.8.9.10
New 9-9	New oil well	J6.167NE150m	1.5.6.7
New 9-10	New oil well	3-13SW100m	1.3.4.5.6.7
New 9-11	New oil well	3-127E150m	1.2.3.4.5.6
New 9-12	New water well	J8-126E150m	1.5.6.7.8.10.11.15.20
New 9-13	New water well	8-156W150m	1.8.10.11.15.20
New 9-14	New water well	6.14NE200m	1.4.5.19

Table 6.7 Specific measures for oil and water wells in Case 3

Well name	Measure	Horizon (for simulated reperforating)
J6.806	Oil well to injection well	5.8.9.10.21
H7-108	Oil well to injection well	5.8.10.17.20.21.23
H6.106	Oil well to injection well	1.5.8.15.20.21.23.24
T8-176	Oil well to injection well	1.6.7.10.11.12.15.20.22
J7-176	Oil well to injection well	1.5.6.7.11.12
6.14	Oil well to injection well	1.5.6.7.8.9.10.11.12.13.20
T6.116	Reperforating of oil well	1.5.20
4-14	Reperforating of oil well	4.5.6.7

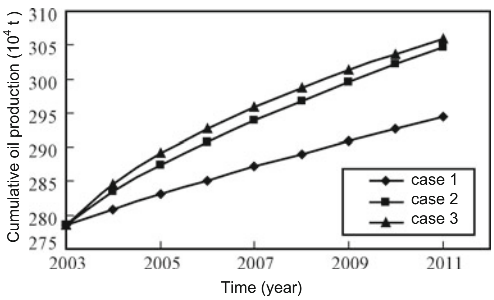


Fig. 6.21 Comparison of cumulative oil production in different cases

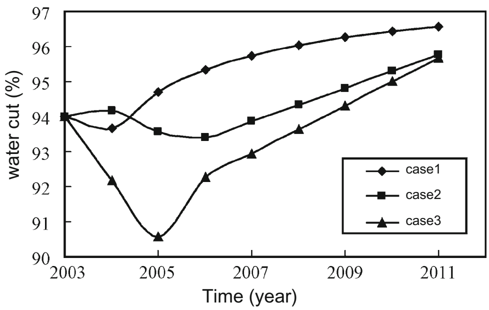


Fig. 6.22 Comparison of water cut in different cases

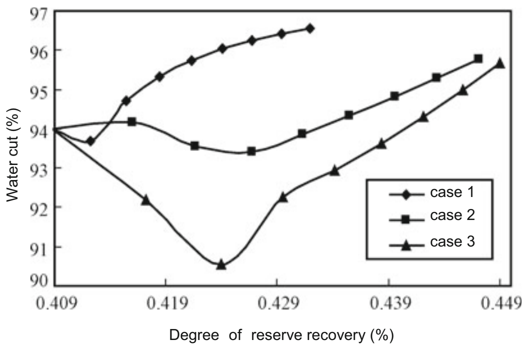


Fig. 6.23 Relation between degree of reserve recovery and water cut in different cases

By examining the development indices of the three cases, it shows that the oil production in Case 1 increases slowly without high-production period but with a low annual oil production. The two other cases with the drilling of adjustment wells have three to four years of unstable high-production period, having much better development effect than that in Case 1. In December 2011, the cumulative oil production in Case 2 and Case 3 were 300.8×10^4 t and 305.9×10^4 t, respectively. In eight years, the cumulative oil production of the two cases are 26.19×10^4 t and 27.40×10^4 t, which are 4.71×10^4 t and 5.92×10^4 t, more than that in Case 1, respectively. In addition, Case 3 produces 1.21×10^4 t more oil than Case 2, with an annual oil increase of 300 t but at the cost of five more oil wells, showing poorer economic benefits.

Comprehensive comparison and analysis shows that Case 2 that adjusts well patterns with vector optimization is the best case.

6.3 Optimal Design and Application of the Vector Well Pattern in Wanglongzhuang Fault Block Reservoir

6.3.1 Overview of Wanglongzhuang Reservoir

The Wanglongzhuang block reservoir is located to the east of Nipei-Zhangpu tectogene in the scarp to the northwest of Chajian subsag of Jinhu sag. With a buried depth of 1475–1830 m, an overlap oil area of 1.7 km^2, and a geological reserve of 184×10^4 t, it is the most abundant of the block reservoirs. The top surface structure of the block reservoir is shown in Fig. 6.24.

Longitudinally, the block reservoir is divided into four segments, E_1f_1, E_1f_2, E_1f_3, and E_1f_4, with major oil reserves in E_1f_2, E_1f_3 of Funing group. E_1f_3 is mainly the delta deposit, subdivided into five subsegments. As for reservoir lithology, it is mainly composed of sandstones.

E_1f depositional stage is in the fault depression sedimentary environment. In E_1f_1 depositional stage, the sag begins to subside and fill in deposit sequence fluvial

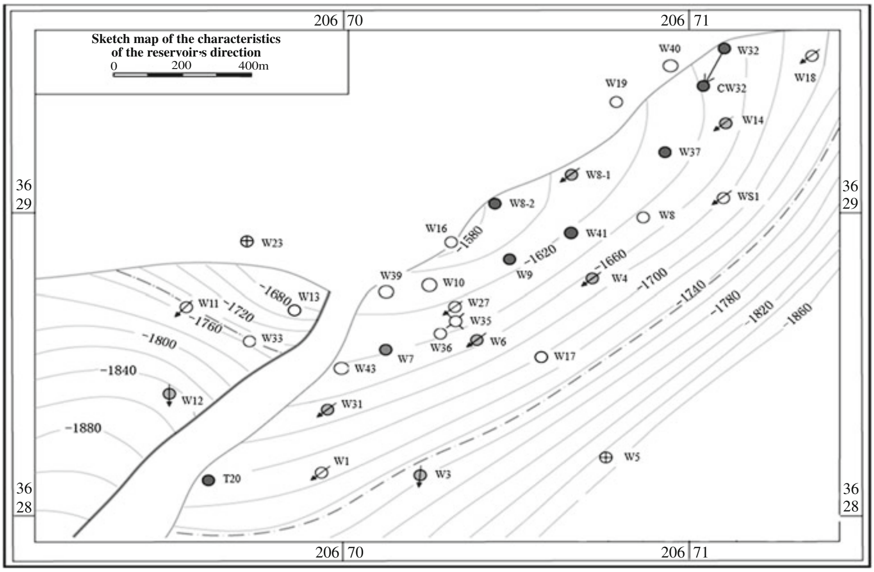


Fig. 6.24 The top surface structure of Wanglongzhuang block reservoir

delta facies rock series; in E_1f_2 depositional stage, water body gradually invades to form shore shallow lake facies thin sandstone in the lower part and beach bar facies sedimentary rock series in the upper part; in E_1f_3 depositional stage, from west to east, there develops delta clastic sedimentary rock series, which are made up of five sand groups from bottom to top, forming a reverse cycle on the whole.

The reservoir characteristics and sedimentary micro-facies types have obvious relations. The main sedimentary micro-facies of Wanglongzhuang block reservoir include the following: The micro-facies of sand bodies in Funing formation is a diversion channel of delta plain subfacies (See Fig. 6.25), natural barrier and delta front subfacies including river mouth bar, underwater diversion channels, sand sheet and shore shallow lake sand dams, etc.

The lithology is mainly feldspar quartz fine sandstone, oolite-bearing quartzo-feldspathic fine sandstone, and gray matter pelitic pore cement, which belong to shore lake and underwater diversion channel facies.

In December 2010, Wanglongzhuang block reservoir had 33 wells. There were 19 oil wells including 16 normal production wells and 14 water wells including 13 converted wells, eight of them normally injected. W-17 was converted from an oil

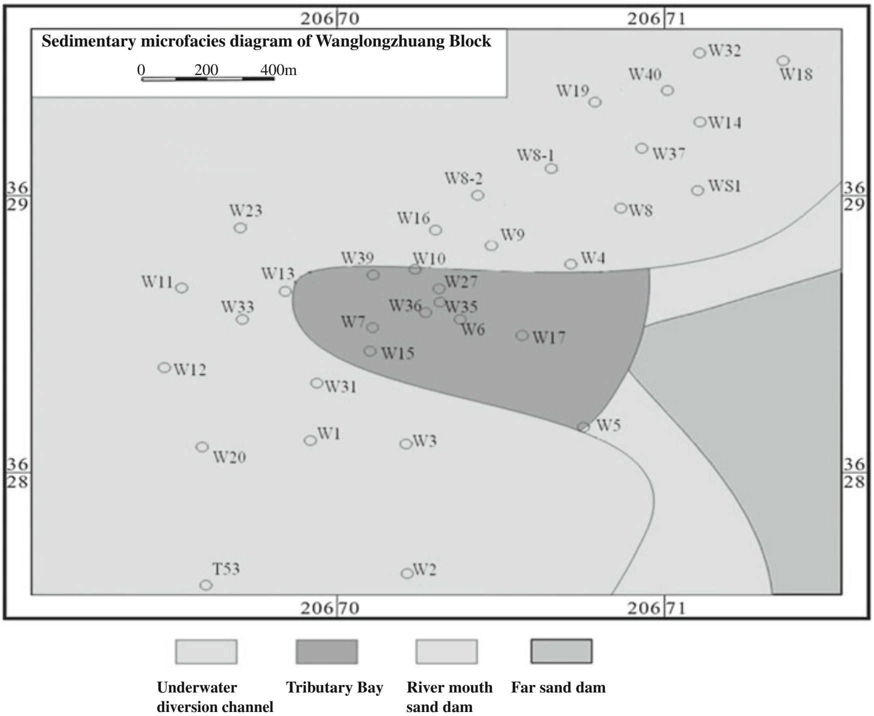


Fig. 6.25 Sedimentary micro-facies diagram of Wanglongzhuang block reservoir

well into a water well in April 1990, and it was reconverted into an oil well for production in July 1999. The number ratio of oil and water wells was 1.4.

In December 2010, the cumulative oil production was 34.64×10^4 t, cumulative fluid production was 94.23×10^4 t, annual oil production was 0.497×10^4 t, cumulative injection was 112.5×10^4 m^3, annual injection was 6.28×10^4 m^3, cumulative injection-production ratio was 1.19, daily oil production was 11.8 t, and average daily oil production per well was 0.74 t. Currently, the water cut is 87.6 %, oil production rate is 0.27 %, degree of reserve recovery is 18.83 %, and daily water injection is 24 m^3.

The main problems existing in the development process of the oilfield are as follows: (1) The well patterns for non-main layers are defective with a low producing reserves; (2) the well patterns for main layers have a poor injection-production relation as most oil wells are under unidirectional water injection effect; (3) the heterogeneity under commingled production leads to poor development effect; and (4) at present, the production rate of the block is low, with low degree of reserve recovery but high water cut.

6.3.2 Directional Characteristics of the Reservoir

Directional characteristics of the provenance, major permeability, and sand body distribution: From the perspective of regional sedimentary environment, the provenance of Wanglongzhuang block reservoir is from the southwest, basically accorded with the main block direction. Its main sand body distribution is along the provenance direction with good sand connectivity, more prone to form high-permeability zone along the block direction. According to the analysis of the historical characteristics of waterflood development, the water breakthrough direction of oil wells was mainly in the southeast to the northwest before March 2004, and it was accorded with the direction of the edge water propulsion. With the increase of development time and well pattern adjustment, the direction of the water breakthrough became northeast 45° in 2011, showing that the connectivity of oil and water wells along the block direction was fairly good, and the water breakthrough direction of oil wells was unidirectional. The dynamic of the water breakthrough in oil wells confirms the influence of the reservoir deposition law on the water breakthrough direction.

The directional characteristics of the reservoir mainly include the provenance direction, deposit direction, major permeability direction, fracture direction, principal stress direction, structural block direction, and edge water intrusion direction. Through dynamic and geological research, the directional characteristics of Wanglongzhuang block reservoir are shown in Fig. 6.26.

In practical oilfield development, controllable direction includes the direction of the water drive, well line, fracturing fracture, and extension of the horizontal section

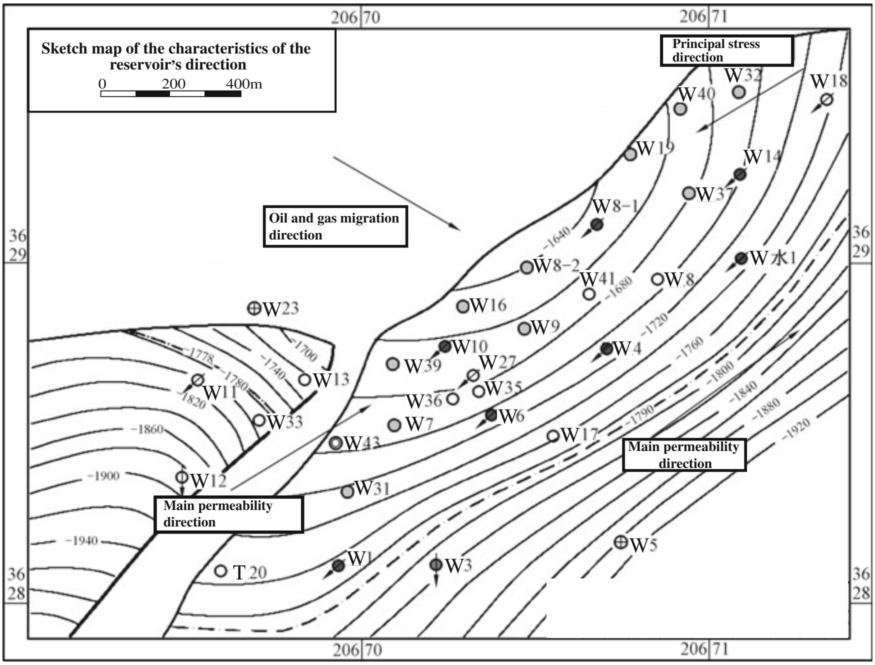


Fig. 6.26 Sketch map of the characteristics of the reservoir's direction

of horizontal wells. According to the vector well pattern theory, artificially controlled direction must have an organic coupling with the actual directional characteristics of the reservoir, to achieve ideal water drive effect.

6.3.3 Design and Effect Forecast of the Vector Well Pattern

(a) According to the vector well pattern theory, the adjustment strategies of Wanglongzhuang block reservoir is mainly focused on applying in different layers different adjustment measures, which mainly include well pattern reconstruction, well pattern optimization and improvement, layers subdivision, adjustment of water drive direction, etc., aiming for a full understanding and fine development to improve the overall development effect of the block.

(1) Well pattern reconstruction. In view of the underimprovement and low degree of reserve recovery of the well pattern in non-main layers, the main layers of potential oil production are $E_1f_3^{3-1}$ plus $E_1f_3^{3-3}$, $E_1f_3^{4-2}$, and $E_1f_3^{4-3}$. As these layers have less wells, basically uncontrolled by injection wells, the main adjustment measures include increasing adjustment wells, using the new adjustment wells to reconstruct the well pattern for non-main layers or layers with a low producing degree ($E_1f_3^{3-4}$, $E_1f_3^{3-15}$), so as to reconstruct the well

pattern. It also takes advantage of advanced technologies such as horizontal wells.

(2) Optimizing the well pattern. $E_1f_2^2$, the main oil layer and the best developed layer, has a wide distribution of reserves and good water drive effect. Major measures are optimizing number of injection-production-well ratio and injection-production ratio and equipping oil wells with multiple injection effects. Based on the remaining oil distribution research of sublayers, the distribution of planar remaining oil and remaining reserves' abundance are clarified to determine the adjustment well deployment area.

(3) Improving the well pattern. $E_1f_2^3$, also a main layer, has relatively rich remaining oil. At present, the main problems are the poor relation between injection and production, and the significant contradiction between layers. The main adjustment measures are optimizing the well pattern by drilling new adjustment wells, reinjecting water into old wells, and converting old wells into injection wells.

(4) Layer subdivision. Because many layers and small layers are in the vertical direction, and significant differences exist in the physical properties and reserve distribution of some layers, the reservoir is perpendicularly divided into relatively independent layers to make the full use of the water injection-production effect and to avoid interlayer interference. A separate well pattern is deployed in E_1f_3, the same injection wells are used in $E_1f_2^2$ and $E_1f_2^3$, while the production wells separately develop each layer.

(5) Adjusting the water drive direction. According to the characteristics of reservoir direction and guided by the vector well pattern theory, the water drive direction is adjusted by changing the edge and isolated water flooding into cutting water flooding, with cutting lines perpendicular to the fault.

According to the vector well pattern theory, the major problems of the present injection-production well pattern are analyzed with a clear understanding of the reserve directional characteristics. In light of the present remaining oil distribution, development adjustment is done, mainly including reinjection of old wells, converting old wells into injection wells and drilling new adjustment wells.

According to the regroup case of layers, the deployment of adjustment wells is specified as follows.

Layers $E_1f_3^{3-1}$ plus $E_1f_3^{3-3}$: Drill a new well to the south of wells W-36 and W-37. Drill a new adjustment well to the northeast of W-17, which can also be drilled to supplement the formation energy, due to the lack of edge water energy. After the conversion of W-36, it forms a waterline along the fault and sand distribution direction. Additionally, it is possible to deploy a horizontal well along the fault direction in the remaining oil enrichment area.

Layers $E_1f_3^{4-2}$ and $E_1f_3^{4-3}$: The well pattern is underimproved with low recovery, and the remaining oil is mainly concentrated in the western block. There is no oil well to the southeast of W-13 or to the east of W-33, which have oil layer an overlapping thickness of over 11 m. It is possible to, respectively, deploy two wells near the fault to the southeast of W-13 and W-33, so as to improve the injection-production well pattern and control the remaining oil, or deploy a horizontal well along the fault direction.

Layers $E_1f_3^{3-4}$ and $E_1f_3^{3-15}$: Convert the oil well W-36 into an injection well. On the one hand, it can supplement the formation energy of the opened layers of W-15. On the other, it can develop injection-production relation with the predrilling adjustment wells to the south of W-17 and W-17 itself, helping the adjustment well to achieve a two-way injection effect.

(b) Layers $E_1f_2^{2-1}$–$E_1f_2^{3-2}$: In view of the high degree of penetration and high water flooding control, the adjustment and deployment should mainly be based on two principles:
(1) Use the new adjustment wells to control the remaining oil enrichment areas;
(2) The main water flooding direction of the reservoir is relatively simple, shown in the water breakthrough of edge water moving to the middle of the reservoir and also shown at the edge of the fault along the direction of the fault; therefore, part of the low-yield or closed wells can be converted into injection wells to form multidirectional injection effect schemes, so as to improve the injection-production relation and increase the sweep efficiency in the middle of the reservoir.

The deployment case is specified as follows: to deploy an adjustment well to the northeast of T-20 and to the southwest of W-31, to deploy an adjustment well to the southwest of W-6 and to the southeast of W-17, and to drill a new adjustment well between W-37 and the injection well W-1.

Conversion wells (or use injection wells): W-31, W-6, W-27, W-10, W-8, W-8-1, W-14.

Drill a new injection well: to the south of W-14.

The well pattern of the adjustment case of $E_1f_2^{2-1}$–$E_1f_2^{3-2}$ is shown in Fig. 6.27.

Layers $E_1f_2^{3-3}$–$E_1f_2^{3-6}$: With a low degree of penetration and low water drive control, this layer should have the following main adjustment strategies:

(1) Crossing layer wells are used to penetrate the layer and improve the degree of penetration and water drive control.
(2) Separated layer water flooding is used for some of the converted oil wells, and water injection is also used in the outer part of the oil–water boundary to supplement the formation energy.
(3) New adjustment wells are drilled in the remaining oil enrichment area.

The specific deployment case is as follows:

Oil wells to be opened: W-7, W-43, W-9, W-16, W-8-2, W-19.

Water wells to be opened: W-27, W-10, W-8-1, W-8, W-31, W-6, W-4, W-North-1.

New adjustment wells: one oil well north of W-8-1 and the southwest of W-19; one oil well east of W8-1 and south of W-37. Besides, an injection well is supplemented between WS-1 and W-37.

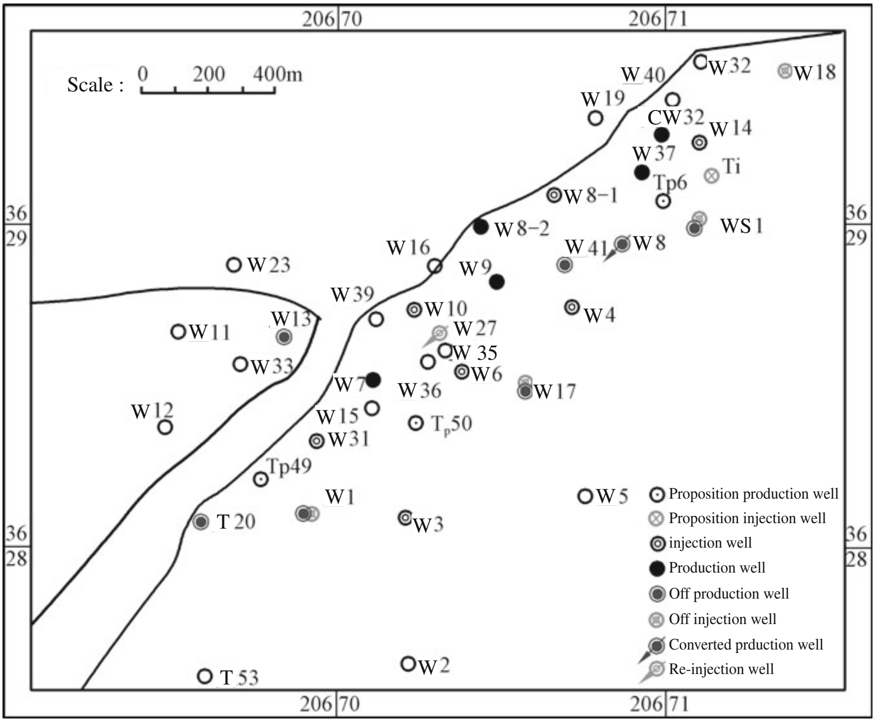


Fig. 6.27 Well location of layers $E^1f_2^{2-1}$–$E_1f_2^{3-2}$ in the adjustment case

The well pattern adjustment case of layer $E_1f_2^{3-3}$–$E_1f_2^{3-6}$ is shown in Fig. 6.28, and the proposed adjustment well pattern of layers $E_1f_2^{3-3}$–$E_1f_2^{3-6}$ is shown in Fig. 6.29.

(c) According to the well pattern reconstruction clue of the hierarchical system, forecast is conducted on the case's development performance on the basis of fine geological modeling and reservoir history matching. To compare the difference in the development effects of branch horizontal wells and vertical wells in the western part of $E_1f_3^{4-2}$ and $E_1f_3^3$, a branch horizontal well taking the place of two vertical wells is used for simulated comparison.

On the basis of sufficient history match, simulated forecast is conducted for each case from January 2011 on, lasting for 15 years. Through the historical analysis of the production, degree of reserve recovery, and composite water cut of forecasting stages of each case, comparison and optimization of the adjustment case are made. The recovery changes in forecast periods of each case are shown in Fig. 6.30, production changes in Fig. 6.31, and water cut changes in Fig. 6.32.

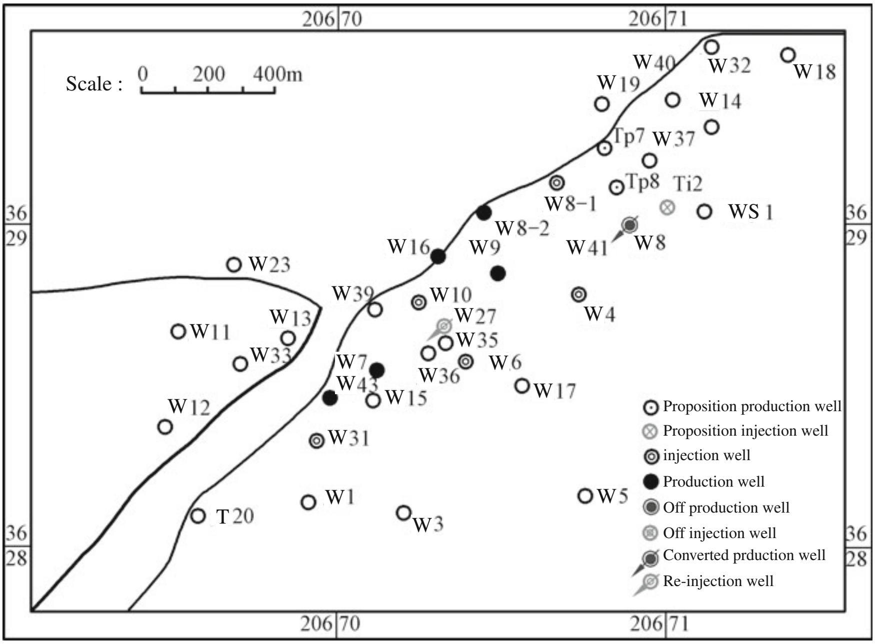


Fig. 6.28 Well pattern of the adjustment case of layers $E_1f_2^{3-3}$–$E_1f_2^{3-6}$

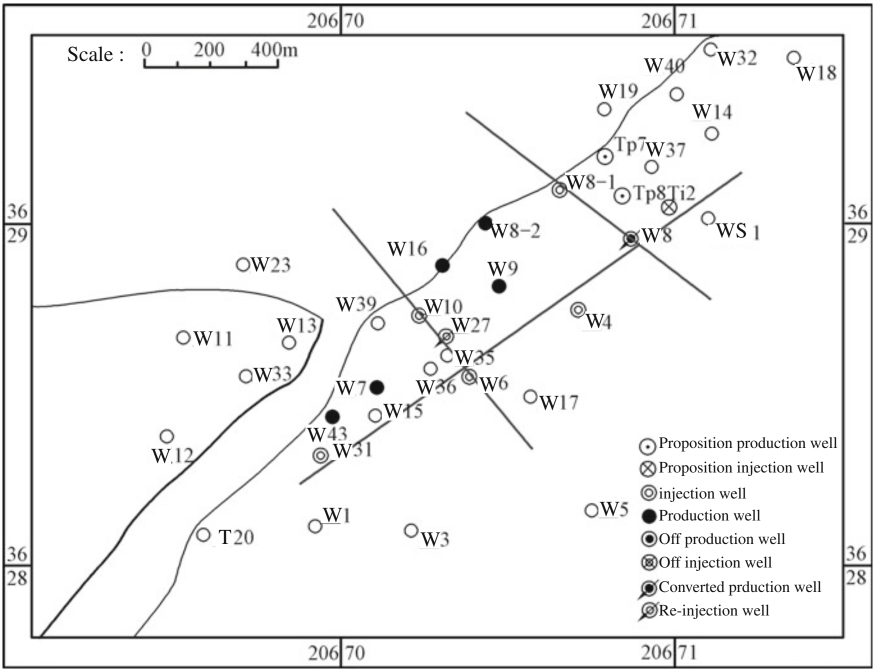


Fig. 6.29 Proposed adjustment well pattern of layers $E_1f_2^{3-3}$–$E_1f_2^{3-6}$

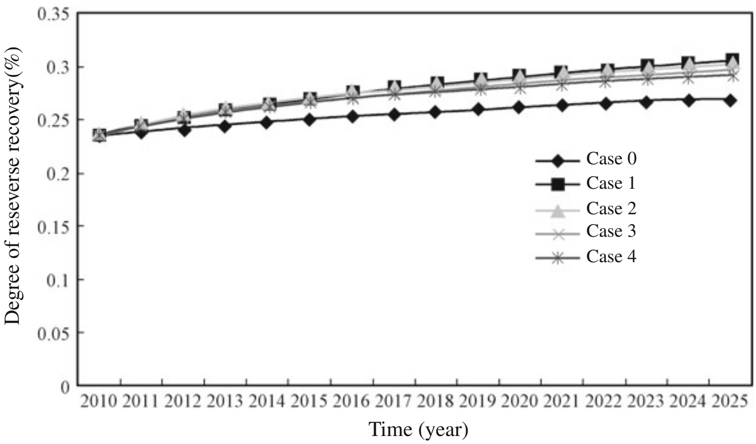


Fig. 6.30 Curves of the predicted changes of degree of reserve recovery in different cases

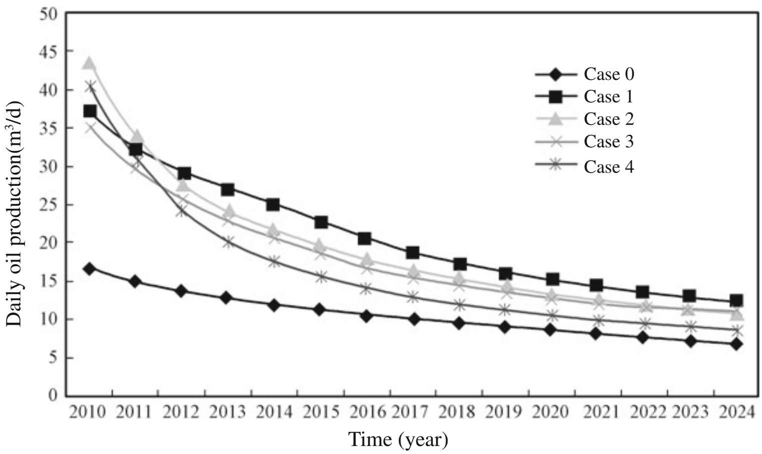


Fig. 6.31 Production changes in the forecast cases

It can be seen from the curves of output, water cut, and degree of reserve recovery of each adjustment case that all adjustment cases can increase the daily oil production by about 40 t, reduce the water cut by more than 10 %, and increase the degree of reserve recovery by at least 2 % in 15 years, as shown in Table 6.8. Regarding the changes of water cut, Case 1 and Case 2 have higher water cut in the beginning, but slower increase, compared with Case 3 and Case 4. Up to 2014, their water cuts are 3 % lower than Case 3 and Case 4.

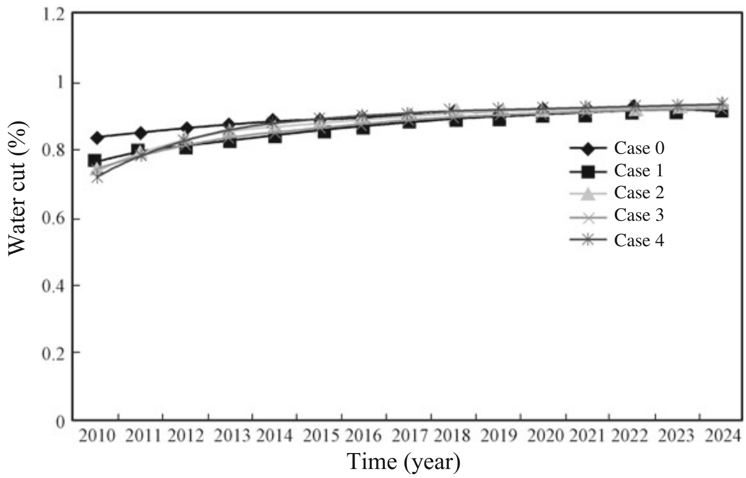


Fig. 6.32 Curves of the predicted changes of water cut in different cases

Table 6.8 Comparison of predicted recovery in different cases

Case	Recovery ratio at stage end (%)	Increased percentage compared with the unadjusted case
Case 0 (not adjusted)	27.04	0
Case 1	30.58	3.54
Case 2	30.21	3.17
Case 3	29.69	2.65
Case 4	29.21	2.17

From the curves of production and degree of reserve recovery of the forecast, Case 1 has the highest cumulative production and degree of reserve recovery, followed by Case 2. Case 4 and Case 2 have high production capability in the beginning, but a relatively lower degree of reserve recovery due to rapid decline. Comparison of Case 1 (with vertical wells) and Case 2 (with branch horizontal wells) shows that Case 2 has a higher production capability than Case 1 in the beginning, but a lower degree of reserve recovery due to rapid decline in 15 years. Comparison of Case 3 and Case 4 shows the same characteristics of Case 1 and Case 2. Comprehensive analysis shows that Case 1 is the best adjustment case.

6.4 Comparative Analysis on the Application of Well Pattern Optimal Theory in Different Units

The above sections have studied the application of the vector well pattern in Zhao'ao Oilfield, Shuanghe Oilfield, etc. On the one hand, a comparison is made of the vector well pattern and actual well pattern at the initial development; on the other, an analysis is made of the change of development effects after the vector well pattern adjustment is applied in the later period. What follows is the comparison and analysis of the effect of applying the vector well pattern technology in different periods and in different oilfields.

6.4.1 *Differences Between the Initial Vector Well Pattern and the Actual Well Pattern*

According to the vector well pattern spacing methods, analysis of the development effects between the vector well pattern production and actual production is conducted on the basis of the geological model in Zhao'ao Oilfield, with the former adopting virtual development methods to analyze the production performance by numerical simulation.

1. Comparison of the development effect in H_3IV3^1 of Zhao'ao reservoir

According to the well pattern optimization calculation in the first section of this chapter, the vector well pattern, in view of the geological characteristics of H_3IV3^1 of Zhao'ao reservoir in Zhao'ao Oilfield, has the best development effects, proved by a comparison of two development modes, as shown in Figs. 6.33, 6.34, and 6.35. Up to December 2003, compared with the original well pattern, the production with the vector well pattern had 5.94×10^4 t more production, 2.9 % more degree of reserve recovery, and more significant production increase in the later stage of high water cut. From December 2003 on, with a forecast of 10 years, the cumulative oil production in the present well pattern is 69.16×10^4 t, with a degree of reserve recovery of 33 %, while the cumulative oil production in the vector well pattern is 87.28×10^4 t, and the degree of reserve recovery is 42 %, 18.16×10^4 t more in cumulative oil production and 9 % more in degree of reserve recovery, respectively.

As for the change of water cut in the oilfield production process, Figs. 6.34 and 6.35 show that the water cut in the vector well pattern is always lower than that in the original well pattern and that the water cut is also lower when the degree of reserve recovery is the same.

2. Comparison of the development effect in H_3IV2^{1-3} of Anpeng reservoir

According to the well pattern optimization calculation in the first section of this chapter, the vector well pattern (in Case 2), in view of the geological characteristics

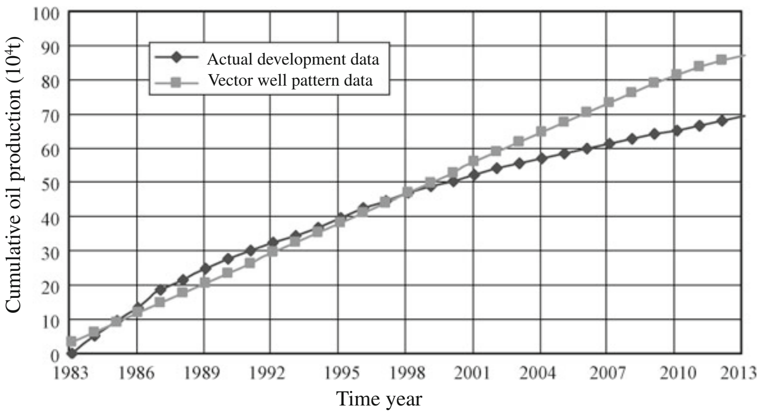


Fig. 6.33 Comparison of cumulative oil production in the former development and development with the vector well pattern

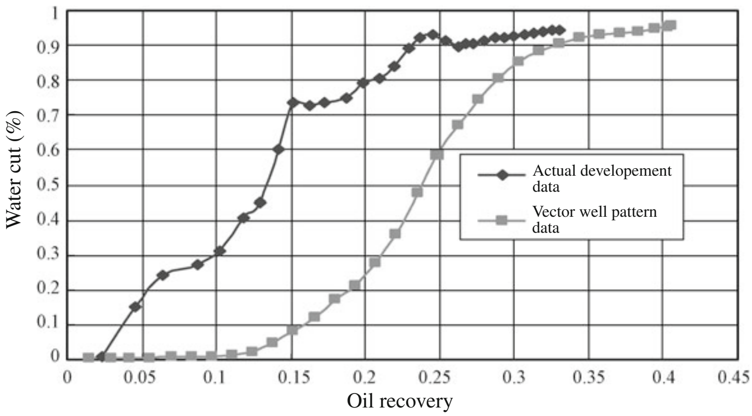


Fig. 6.34 Comparison of recovery in the former development and development with the vector well pattern

of H_3IV2^{1-3} of Anpeng reservoir in Zhao'ao Oilfield, has the best development effects. Up to December 2003, compared with the original well pattern, the production with the vector well pattern had 5.4×10^4 t more production and 2.3 % more degree of reserve recovery. As for the change of water cut in the oilfield production process, Figs. 6.18 and 6.19 show that the water cut in the vector well pattern is always lower than that in the original well pattern and that the water cut is also lower when the degree of reserve recovery is the same.

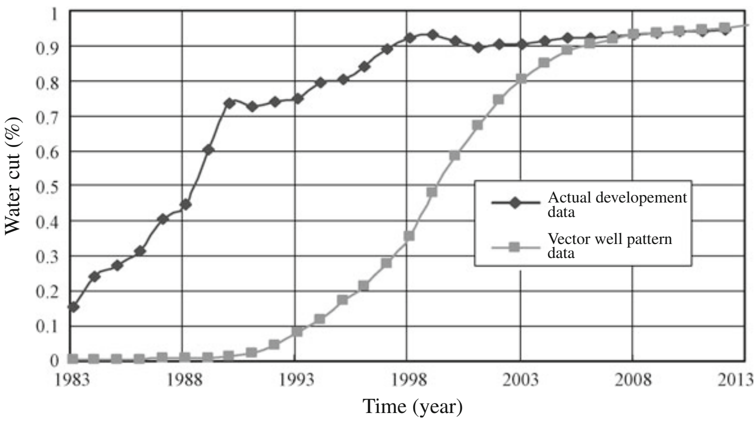


Fig. 6.35 Comparison of water cut in the former development and development with the vector well pattern

6.4.2 *Effect Comparison and Analysis of Applying the Vector Well Pattern in Different Reservoirs*

An adjustment is made of H_3IV3^1 of Zhao'ao reservoir and H_3IV2^{1-3} of Anpeng reservoir in Zhao'ao Oilfield and oil group VI of Jianghe reservoir in Shuanghe Oilfield. Through analog computation, the application results of the vector well pattern theory are summarized in Table 6.9, which lead to the following conclusion.

Table 6.9 Comparison of predicted development effects in ten years after applying the vector well pattern in different reservoirs

Name of the reservoir	Change of cumulative oil production at stage end				Water cut at stage end	
	With actual well pattern (10^4 t)	With the vector well pattern (10^4 t)	Increased production (10^4 t)	Increased degree of reserve recovery (%)	With actual well pattern (%)	With the vector well pattern (%)
H_3IV3^1 in Zhao'ao Oilfield	72.16	78.21	6.05	2.92	95.1	96.2
H_3IV2^{1-3} in Anpeng Oilfield	73.4	78.57	5.17	2.10	96.24	96,59
Oil group VI of Jianghe reservoir in Shuanghe Oilfield	294.4	304.7	10.3	1.51	96.55	95.76
Wanglongzhuang block reservoir	44.23	56.27	12.04	3.54	91.15	92.28

(a) In the reservoirs in which the vector well pattern is applied, H_3IV3^1 in Zhao'ao reservoir has the best development effect. In ten-year forecast, the increase of cumulative oil production is 6.05×10^4 t and the increase of degree of reserve recovery is 2.9 %, followed by H_3IV2^{1-3} in Anpeng reservoir and oil group VI of Jianghe reservoir in Shuanghe Oilfield.
(b) Viewed from the oil production increase, all the adjustments with the vector well pattern have achieved fairly good results, with a considerable increase of degree of reserve recovery of more than 1.5 %. It is quite ideal for oil group VI in Jianghe reservoir with a high water cut.
(c) In combination with the present production status of each reservoir, the lower degree of reserve recovery, and the lower composite water cut, the better adjustment effects are applied in the vector well pattern. Of the reservoirs, Zhao'ao reservoir has the lowest degree of reserve recovery and the lowest composite water cut.
(d) It is best to apply the vector well pattern methods in the early development period, which will achieve better development effects with the highest increase of degree of reserve recovery in the same time span. Taking H_3IV3^1 in Zhao'ao reservoir as an example, fitting and forecasting after production before 2013 show that with the present well pattern, the cumulative oil production is 69.16×10^4 t, and the degree of reserve recovery is 33 %, while with the vector well pattern, the cumulative oil production is 87.28×10^4 t, boasting an increase of 18.12×10^4 t, and the degree of reserve recovery is 42 %, boasting an increase of 9 %.

Chapter 7
Complex Well Pattern Optimal Design

This chapter mainly discusses the optimal design of well patterns, which is based on the principle and placement method of the vector well pattern in perspective of the actual oilfield data or the type of production wells. Focusing on a specific reservoir, the reservoir distribution, sedimentary characteristics, and reservoir directional characters can basically recognized. Based on the technology of reservoir fine description, reasonable well patterns can be chosen to effectively control the geological reserves with the help of modern drilling technology in order to get the best effect of water flooding.

7.1 Overview of Complex Well Pattern Optimal Design

In recent years, oilfields developed all over the world are confronted with a problem how to get more crude oil and natural gas and reduce the costs in the same period. Horizontal well technology has brought a method to reach the goal and make it possible to develop uneconomical oilfields. Horizontal well drilling was not a new concept. It has been accepted worldwide. Many oilfields are continuously increasing the number of horizontal wells in order to promote the economic benefits of oilfield development and increase the reservoir's drainage area. Expanding the length of the horizontal section to efficiently control the gas/water coning, etc., all these have brought significant effects to the improvement of oilfield development. Because oil and gas are non-renewable natural resources, people try their best to increase recoverable reserves and enhance recovery to make it possible to develop the oilfields which were unlikely to have economic benefits in the past. There are two major aspects in enhance oil recovery (EOR): One is to change the methods of enhancing oil recovery continuously, including various physical and chemical

D. Liu and J. Sun, *The Control Theory and Application for Well Pattern Optimization of Heterogeneous Sandstone Reservoirs*, Springer Geology,
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methods, and the other is to improve oil recovery (IOR), which is related to the development strategy, well pattern placement, and the increase of reservoir's drainage areas in order to promote the oilfield's recoverable reserves. Because oilfields are developing in the direction of comprehensive utilization of new technologies, the two aspects are not strictly separated, so they are both called enhanced recovery method. Among the technologies of EOR, horizontal well drilling technology has been widely applied and a large number of horizontal wells were drilled. Later, because directional wells could not meet people's higher requirements or the costs were too high, multilateral wells (several horizontal wells or directional wells drilled in one borehole) were adopted in order to reduce drilling costs and increase reserve control, drainage area, and production, and to meet the needs of the development of different special types of oilfields, which include multiple reservoirs, small fault block reservoirs, small sand body reservoirs, etc. This technology can increase drainage area, control reserves, and oil production and reduce development costs, thus greatly improving the recovery.

The main purpose of horizontal wells and multilateral wells is to get larger drainage area and increase controlled reserves as well as production, to reduce drilling cost, to develop uneconomical fields or marginal fields, and finally to improve exploration benefits. Its main advantages include the following aspects:

a. Reducing development cost, including drilling cost, wellhead device cost, surface pipe network cost, platform cost, and processing cost. Because each multilateral well has only one main borehole, it reduces the vertical part above each multilateral well. Therefore, one multilateral well is equal to many horizontal wells. This method can save various costs by reducing drilling wells and surface facilities and increasing the platform's efficiency. According to statistics, complex well development cost can be reduced by more than 44 %.
b. Increasing recoverable reserves. Due to the decrease of drilling cost, the uneconomical oilfields and the inefficient marginal fields can be explored. By drilling multilateral wells in inert or bypassed areas, unexplored small fault blocks or small oil sand bodies can be developed with only a little increase of cost. This can greatly increase the field's recoverable reserves.
c. Promoting production and speeding up the investment recycling. As one multilateral well is equal to many horizontal wells, it can greatly increase the well's production and the reservoir's drainage area. Consequently, it can promote oil production rate, quicken the return of investment, and improve production efficiency.
d. Reducing environment pollution. A smaller number of drilling sections reduce the processing of mud and rock debris, and the pollution with it. A smaller number of wells and the surface facilities also reduce environmental pollution.
e. Better use of the platform and wellhead assembly. Because one multilateral well is equal to several horizontal wells, with the increased production, it can get efficient use of the platform and wellheads.

f. In favor of the management of reservoir. Because one multilateral well is equal to several horizontal wells, it is convenient for the management of the wellhead assembly and platform. Consequently, fewer wells are needed above the ground. With the continuous connection between the multilateral well and reservoir, it can increase the reservoir's drainage area and the recognition about the layer, and facilitate monitoring and control of the reservoir.
g. Improving the marginal oilfield's economy. With this technology, the number of drilling wells decreases, the drilling cost declines, and the use efficiency of platforms and surface facilities increase. This reduces the unit cost of crude oil extraction and brings more economic benefits to the marginal oilfield's development.
h. The use of existing wells or new wells. A multilateral well can be drilled with sidetracking technology on the basis of the existing well or a new well can be drilled. The flexibility brings much convenience to the application of multilateral wells.

7.1.1 A Brief Introduction to the Development of Horizontal Wells

1. The development of horizontal well research and application

Horizontal well technology is a major breakthrough in the world's oil industry. It endows uneconomical oilfields with exploration values in some areas that cannot be exploited or have poor exploitation effects with vertical wells. This brings great economic benefits to the oilfield development. Horizontal well technology was introduced and applied to oilfield production in the late nineteenth and early twentieth centuries, but it developed slowly at first. Since the 1980s, the trend of its development has been accelerating. In particular since the 1990s, it has made such considerable progress that many people fail to realize the current level of the drilling technology and its potential capacity.

Viewed from the application of the horizontal wells abroad, they are mainly suitable for the following four types of oil/gas reservoir: thin layer of oil/gas reservoirs, naturally fractured oil/gas reservoirs, gas and water coning reservoirs, and bottom water oil/gas reservoirs. In China, the most successful developed reservoirs by using horizontal wells are the high water cut reservoir and the heavy-reservoir with thermal recovery, and the reservoirs with worst effects are low-permeability reservoirs, ultra-low-permeability reservoirs, and ultra-viscous reservoirs.

The horizontal well refers to a well whose deviation is bigger than 85° in a well section. The difference between a horizontal well and a side-tracked well lies in the fact that the former generally refers to a newly drilled well above the ground with a horizontal section length between 300 and 1500 m, and the latter refers to a well which is sidetracked from an existing vertical well with a horizontal section length between 30 and 150 m. Horizontal wells are divided into three major categories according to the radius of curvature:

a. The long-radius horizontal well: The radius of curvature is 300–1000 m and the deflection rate is <6°/30 m.
b. The mid-radius horizontal well: The radius of curvature is 199–250 m and the deflection rate is 6°/30–20°/30 m.
c. The short-radius horizontal well: The radius of curvature is 7–15 m and the deflection rate is 6–15°/m.

2. The reservoir type for horizontal wells

There are several types of reservoir that adapt to the application of horizontal well.

a. Bottom water and gas cap reservoirs. The horizontal well can effectively restrain water and gas coning and enhance recovery. It can form a low-pressure area in a certain range but a vertical well only makes a low-pressure point. Under the same pressure, the production of the horizontal well may be more than that of the vertical well.
b. Naturally fractured reservoirs. There is bigger probability of encountering natural fractures by drilling along the horizontal section, thus improving the capacity of fluid flow and speeding up the exploitation of reservoirs.
c. Reservoirs difficult to develop with conventional technologies. For instance, irregular-shaped reservoirs, thin reservoirs, and low-benefit reservoirs produced with vertical wells.
d. Heavy oil reservoirs: Compared with vertical wells, horizontal wells have a significant effect for exploiting asphaltene or viscous reservoirs with the steam-supplemented gravity drive.
e. On the sea or in environmentally sensitive areas: Due to the high cost of the well site, horizontal wells have incomparable superiority to vertical wells. Only a small number of horizontal wells can control a vast drainage area.
f. Multilayer reservoirs: If reservoir conditions permit, the step horizontal well or branch horizontal well can be used in the drilling process.
g. Low-permeability reservoir: Giger pointed out that if the length of a horizontal well or a horizontal section is bigger than the reservoir thickness, the whole production of a horizontal well is higher than that of a fully opened vertical well. The longer the horizontal section, the better the production.

There are three major purposes of using horizontal wells: First, this method is used to develop the marginal reservoir which cannot obtain economic benefits by the vertical well drilling, and the horizontal well technology is almost an unavoidable choice. Second, it is for improving the oil production rate and enhancing the oilfield's recovery. The use of horizontal well technology at this time is not for economic purpose. Third, the horizontal well is used to improve the reservoir's producing degree to achieve the purpose of high recovery.

3. Productivity formula of the horizontal well

Scholars in China and other countries mainly adopt the analytic method and simulation method in the research of horizontal well productivity. Based on a mathematical model, the analytic method can help deduce the analytic solution to the productivity of the single-phase flow or multiphase flow horizontal wells through appropriate assumptions and simplifying the equation's initial and boundary conditions. Another method is to get the productivity formula of horizontal wells by means of the conformal transformation, mirror image mapping, potential superposition principle and the equivalent percolation resistance law, and so on, through appropriate conversion. The simulation method consists of two major types, physical simulation and numerical simulation. Further, there are two main types of numerical simulation method: One is the mathematical model which can afford an effective solution, based on which a software is designed, and the other is to accurately describe the horizontal well to simulate its development on the basis of the simulation software in the vertical well.

In 1958, Merkulov, a scholar of the former Soviet Union, first put forward the analytic formula for calculating the horizontal well productivity, which is suitable for the pseudo-radial flow and parallel flow. For the circular reservoir, the horizontal well is located in the center with the assumption of incompressible fluid, constant pressure boundary, with the formation permeability anisotropy taken into consideration.

Borisov, also a scholar of the former Soviet Union, systematically summarized the development and production principle for horizontal wells and put forward a theoretical model of horizontal well productivity under the following assumptions: (1) the steady-state flow, (2) the single-phase flow and incompressible fluid, (3) the isotropic homogeneous reservoir regardless of formation damage, and (4) the horizontal well located in the middle of the reservoir and the ellipse drainage area. The model was deduced by the mathematical method, assuming that a horizontal well is located in the box piled reservoir.

In 1983, according to Borisov's formula, Giger from France and others studied the issue of horizontal well reservoir with the electric model, and in 1984, they put forward the productivity formulas of horizontal wells located at the center of the reservoir, but there was no detailed derivation process. The formula's assumptions and Borisov's are basically the same. Giger, Reiss, and Jourdan also offered the equivalent permeability K' instead of the original type of K_{h} in 1984. This equation can be applied to heterogeneous reservoirs. Giger's equation and Borisov's equation have the same shortcoming that they both took the wellbore pressure as constant and did not consider the influence of the horizontal well length.

In 1986, Joshi from the USA used the electric field flow theory, assuming that the horizontal drainage area was an ellipsoid focused on the two endpoints of the horizontal well, which simplified the three-dimensional seepage problem to a vertical and two-dimensional problem within the horizontal plane. It made a detailed deduction of the formula of horizontal well productivity of the homogeneous isotropic reservoir based on the theory of potential energy. At the same time, according to Muskat's concept of reservoir heterogeneity and eccentric distance, he proposed a comprehensive capacity calculation formula of horizontal wells with permeability anisotropy and eccentric distance taken into consideration.

In 1988, Babu and Odeh established a mathematical model of unstable seepage of horizontal wells aimed at the box-type reservoir through the analysis of a physical model, on the basis of whose solution he first worked out a formula of horizontal well productivity under the condition of the quasi-steady state with the principle for material balance. Babu's and Odeh's formulae are more suitable for the commonest cases in most general situations.

In 1990, Renard and Dupuy summarized Joshi's and Giger's horizontal well productivity equation, introduced the skin factor, corrected the steady-state equation, and discussed the damage effect near the wellbore formation. Because the oil production index of the horizontal well per unit length is low, the influence from the skin damage of horizontal wells is less than that of vertical wells, and the equation can only be used for the round, oval, or square drainage area.

In 1996, Elgaghad, Osisanya, and Tiab proposed a productivity equation more complex than that for the elliptical or rectangular drainage area. It assumes that the reservoir includes a series of semicircles and two rectangles. This equation is relatively simple, for it does not have to calculate the horizontal drainage radius r_{eh}, and the determination of the parameter η is enough.

In 1991, Frick and Economides deduced the skin factor analytical formula of horizontal wells according to the phenomenon that the time length during which the head of the horizontal section is exposed to the drilling fluid is longer than that of its end and an ellipsoid damage area is formed. It can be directly attached to the formula of calculating horizontal well productivity (e.g., Joshi's formula). They also gave a calculation formula which takes the productivity of the skin effect into consideration.

In 1996, DOU Hong'en regarded the horizontal well as a vertical well which is sandwiched between two impermeable boundaries with the horizontal section length as the reservoir thickness. He studied the productivity according to the principle for mirroring mapping and superposition, and worked out a new horizontal well formula. The formula used the concept of equivalent permeability put forward by Giger to rectify the homogeneous formation and got a higher accuracy of rectifying the non-homogeneous formation than that obtained by using permeability anisotropy coefficient in Joshi's formula. DOU Hong'en also pointed out that Joshi divided the three-dimensional flow of the horizontal well into two parts, the level ellipsoid drainage and vertical cylinder drainage, which are overlapped and may cause errors in the productivity formula.

In 1991, XU Jingda expounded theoretically the assumption that the ellipsoid drainage area in Joshi's formula is an ideal mode of seepage. He holds that such a process shortens the distance through which the fluid flows into the bottom hole, so the calculated production is higher than the actual capacity. Joshi's formula was used in the rectangular drainage of infinite length and assumed that the drainage boundary of the ellipse is located at infinity. Obviously, the distance through which the fluid flows into the well is the longest and the calculated productivity is the least.

4. Combination of well patterns

Detailed discussions of vertical wells can be found in monographs and textbooks. Besides, the calculation of the combination of well patterns and calculation of relevant parameters have also been developing rapidly in recent years. The five-spot injection-production horizontal well pattern and the combination of injection-production well pattern for both horizontal wells and vertical wells are the most common. The productivity calculation, sweep efficiency, water breakthrough time, reasonable well spacing, etc., which correspond to each kind of combination of well patterns have been thoroughly researched, including the above two modes of well pattern combination. These researches have covered the horizontal well development technology in low-permeability reservoirs and related technological parameters from the perspective of horizontal well pattern optimization and the form of reasonable well patterns of the combination of horizontal and vertical wells.

5. SAGD in heavy oilfield development

Horizontal well steam-assisted gravity drainage (SAGD) technology is an effective means for the development of viscous and ultra-viscous oil. The double horizontal well SAGD is developed by taking full advantage of this technology. It affords an effective way for the development of viscous oil and ultra-viscous reservoirs and greatly improves reservoir development benefits.

6. Large displacement horizontal well technology in beach marginal oilfields

For beach marginal oilfields, conventional platform development does not work but large displacement horizontal well technology can solve this problem. In June 2000, the first large displacement horizontal well was drilled in the Bohai Bay with China's independent technology. This provides a new way to get an efficient development in beach marginal oilfields. In recent years, rapid progress has been made in large displacement horizontal well drilling technology.

7.1.2 Multilateral Wells

The first multilateral well, named Den MD-9, was drilled on the sea close to Denmark in 1993. At present, the technology of multilateral wells is widely used in various fields all over the world. Many famous oil service companies provide technical services of and conduct researches on the application of this technology, including Halliburton, Baker Hughes, Sperry-Sun, Schlumberge, and Weatherford. Now, most of the completed multi-branch wells are located mainly in offshore oilfields, such as the North Sea and the Gulf of Mexico, because the advantages of this technology can be best reflected on the sea. Besides, it is also used in North America and the Middle East regions. Since 2002, when the first fishbone-shape multilateral well was drilled in Bohai Oilfield, favorable production effects have been obtained.

1. Drilling and well completion of multilateral wells

Multilateral well drilling technology is one of the most difficult parts in the application of multilateral well technology. Some of its technologies, such as underground technology, drilling technology, and well completion technology, are much more difficult than those in general vertical and horizontal wells. It is also the main reason for the slow development of multilateral well technology. Now, Halliburton, Baker Hughes, Schlumberger, and Sperry-Sun and many China's oil service companies have a complete set of drilling and well completion technology.

Multilateral well drilling process is to usually drill the main borehole and then complete the well before the multilateral boreholes are drilled. In the main borehole, there are two types of casing. One is fully enclosed. In this case, the casing must be worn out with a drilling bit to open a "window," through which the formation can be reached by sidetracking. The other is to open the casing window before the casing is set into the wellbore. Of course, before the well completion and side-tracking, the opened window is closed in a certain way. It is opened only at the time of sidetracking. The number of windows corresponds to that of sidetracking directions and it is designed in advance. In sidetracking, the windows are opened with tools drilling into the formation. Whatever you do, you have to use a whip-stock in sidetrack drilling (see Fig. 7.1).

A variety of systems that conform to the production well have been developed for multilateral well completion. They mainly include the completion tools developed by companies such as Halliburton, Baker Hughes, and Sperry. At present, the well completion is classified into the following types: open-hole completion, partial open-hole completion (mainly the sections in the branches), partial slotted liner completion (mainly the sections in the branch), full cased hole completion, etc. Due to different methods of well completion and the different ways of connecting the main borehole and the holes in the branches, different types of multilateral wells

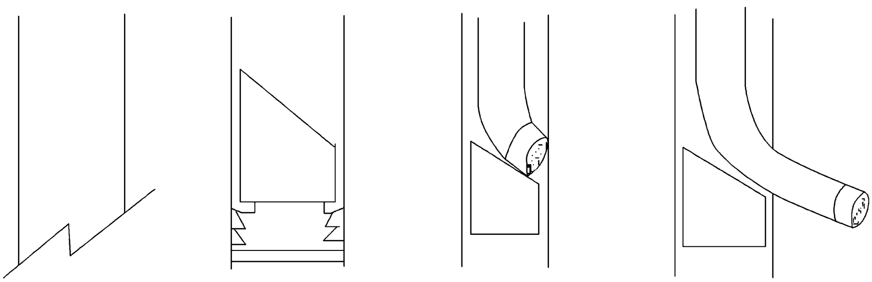


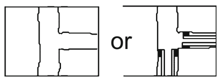
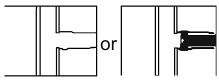
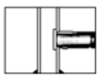
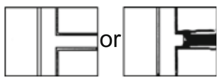
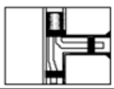
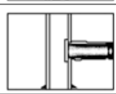
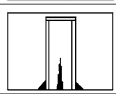
Fig. 7.1 Process of drilling

come into being. With the development of well completion technology, the latest intelligent well completion technology is applied in multilateral wells. For the purpose of reasonable development of the reservoir, it is used to automatically analyze the production of many branches through intelligent-control instruments installed in each branch and automatically adjust each branch's production and control the production switch according to the dynamic parameters.

2. Classification of multilateral wells

So far, a great number of multilateral wells have been drilled all over the world. They differ in the purpose of well design, function, and production mode. To be specific, they are different from each other in the mode of well completion and the way of connecting the main borehole and the boreholes in the branches. Therefore, there are different types of multilateral wells. Now, multilateral wells are classified into two kinds: One classification is based on drilling mode and well completion mode, their levels of difficulty and complexity, and the connection relation between the main borehole and the boreholes in the branches. They are divided into seven levels: level 1, level 2, level 3, level 4, level 5, level 6, and level 6S (a sublevel) (see Table 7.1). The second classification is based on the basic functions of the production well (see Table 7.1).

Table 7.1 Classification of multilateral wells in terms of complexity

Standard	Description	Case
1	Open/non-supporting joint Open-hole completion or placement of slotted liner in the main shaft and the branch wells	
2	Pouring cement in casing pipe to achieve well completion in the main shaft, open-hole completion of branch wells Open-hole completion or placement of slotted liner	
3	Casing completion in the main shaft, branch well placed casing without cement. The casing pipe of branch well hung in the main shaft without cement	
4	Pouring cement in casing pipe to achieve well completion in the main shaft and branch wells Both cement completion at the junction	
5	Maintaining pressure balance at the junction and formation in the production (injection of cement is not recommended) Isolation by packer	
6	Maintaining pressure balance at the junction and formation in the production (injection of cement is not recommended) Casing completion	
6S	Use the separator in the well There are two branches with the same size in a large size	

3. Types of reservoir that fit multilateral wells

Because of the characteristics of multilateral well technology, it is not suitable for the development of all reservoirs. Therefore, we must choose reservoirs when adopting this technology. Otherwise, its superiority is unlikely to be brought into full play. Reservoirs that suit multilateral wells include the following major types: reservoirs with small fault blocks or independent oil sand bodies, lenticular reservoirs, reservoirs with strong directivity, multilayered reservoirs with interlayers, poor reservoirs, water channeling reservoirs, reservoirs with two kinds of natural fracture system, reservoirs where crude oil gathers at the top of the perforation section, attic reservoirs, water-drive reservoirs, etc. In addition, this technology can also be adopted with satisfactory results for the reservoirs whose development is restricted by the offshore platform, and the oil districts left to be developed in the future and the reservoirs in which normal well arrangement cannot be accomplished due to the surface factors. The specific reservoir types are as follows.

a. Reservoirs with small fault blocks or independent oil sand bodies: If people have a clear understanding of such a reservoir, they can drill multilateral wells through the main borehole to produce oil from different blocks, which is more economical than drilling many vertical wells, as shown in Fig. 7.2.
b. Lenticular reservoirs: They are arranged in the form of isolated lenses and each vertical well or horizontal well can thread several reservoirs, so a main borehole with several multilateral wells can be used to exploit different reservoirs, as shown in Fig. 7.3.

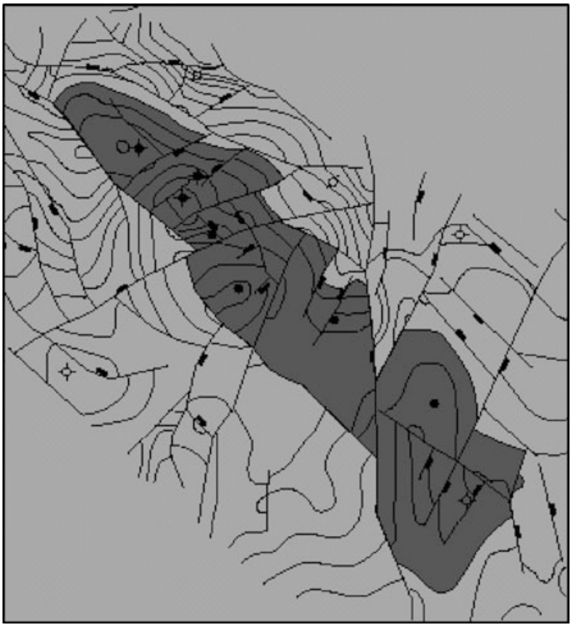


Fig. 7.2 A reservoir with small fault blocks

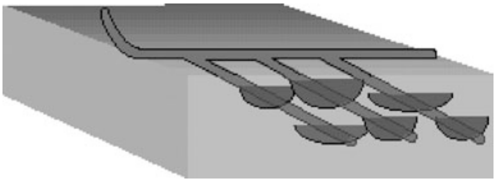


Fig. 7.3 A lenticular reservoir or independent sand bodies

c. Reservoirs with strong directivity: There exists high permeability or natural fracture in a certain direction. A careful design of multilateral wells in this kind of reservoir can increase recovery. In this case, the direction of multilateral wells should be vertical to that of the main permeability direction and the fracture direction when multilateral wells are arranged.
d. Multilayered reservoirs with interlayers: Because of the poor vertical conductivity and the reservoir separation, several parallel multilateral wells can be used to exploit different reservoirs, as shown in Fig. 7.4.
e. Poor reservoirs: They mainly include tight low-permeability reservoirs, etc.
f. Water channeling reservoirs: In a water-drive reservoir, water breakthrough occurs in high-permeability zone but the injected water fails to reach the low-permeability zone. If so, the multilateral wells can be drilled in the area of water injection. The direction and the length of the multilateral wells can be determined according to the circumstance of water flooding layer. That is, a linear displacement between the horizontal injection well and horizontal production well is adopted instead of a crossed radial displacement. This method can improve the oil displacement effect and reduce the inert area, as shown in Fig. 7.5.
g. Reservoirs with two kinds of natural fracture system: Because there are two kinds of natural fracture, and a horizontal well can cross only one group of fracture system, to thread the multilateral wells with the cross-mode or vertical orthogonal mode can have a better efficiency of oil extraction, as shown in Fig. 7.6.
h. Reservoirs where crude oil gathers at the top of the perforation section to form inert areas such as attic oil zones or top oil zones. In this case, multilateral wells can be used to increase the oil drainage area and channels, as shown in Fig. 7.7.
i. Attic reservoirs: Crude oil gathers at the top of the structure and cannot be reached with the original well pattern, as shown in Fig. 7.8.
j. Water-drive reservoirs: Multilateral wells can be drilled to improve the water flooding effect in the original well pattern. New branches of wells can be drilled in the original injection well as the production well or vice versa. Multilateral wells used as injection wells can help optimize pressure control and improve oil displacement efficiency, as shown in Fig. 7.9.
k. Reservoirs whose development is restricted by the offshore platform: The design of an offshore platform and the wellhead is designed for the original oilfield. New reservoirs or fault blocks reservoirs will be discovered with the development of the oilfield, the deep recognition of the formation or more thorough

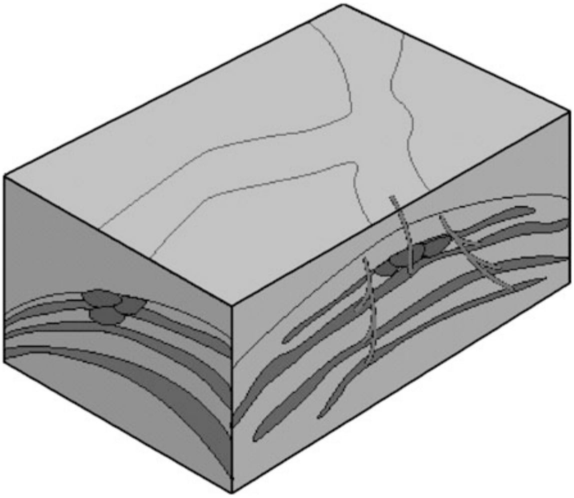


Fig. 7.4 A multilayered reservoir with interlayers

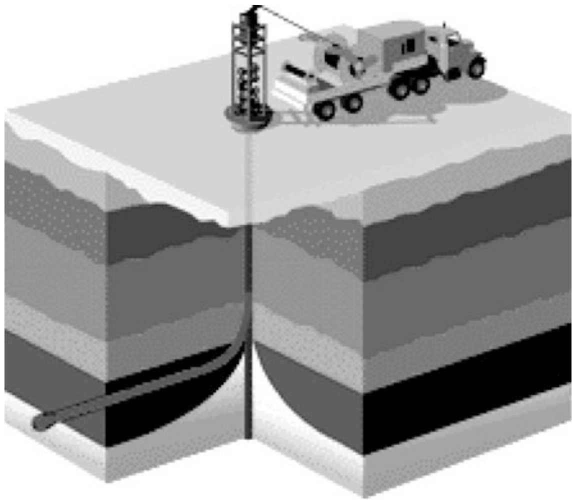


Fig. 7.5 A water channeling reservoir

exploration. However, they cannot be put into production with the original platform. Therefore, multilateral wells can be drilled to exploit new reservoirs or blocks reservoirs, as shown in Fig. 7.10.

l. Oil districts left to be developed in the future: When an overall planning of the oilfield is made, the main borehole is used to exploit the present region first. The next step is to drill multilateral wells to exploit other formations and new regions, as shown in Fig. 7.11.

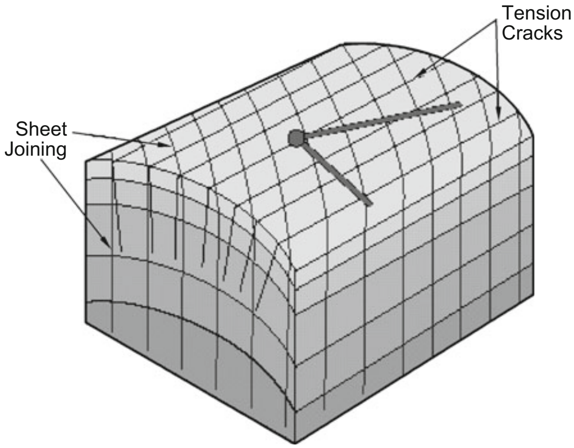


Fig. 7.6 A reservoir with two kinds of natural fracture

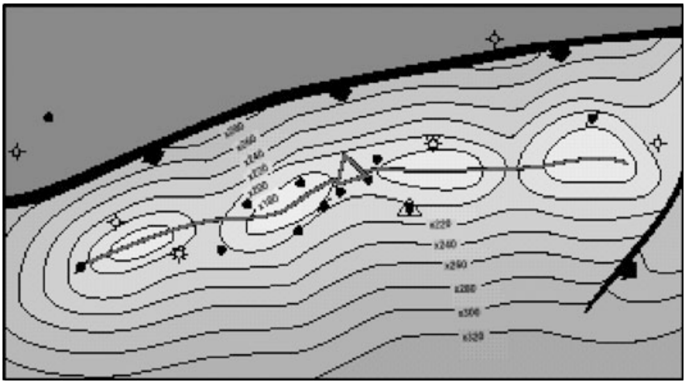
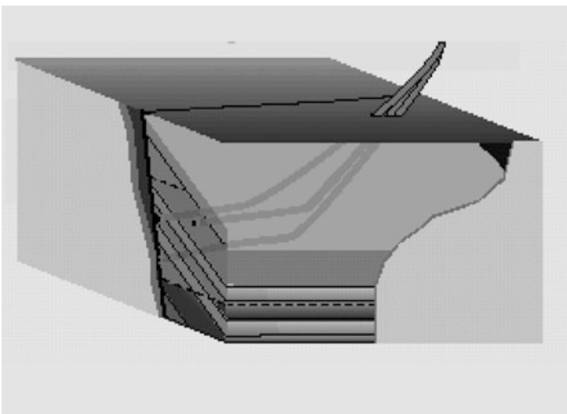


Fig. 7.7 Oil gathering at the top section of perforation

Fig. 7.8 An attic reservoir



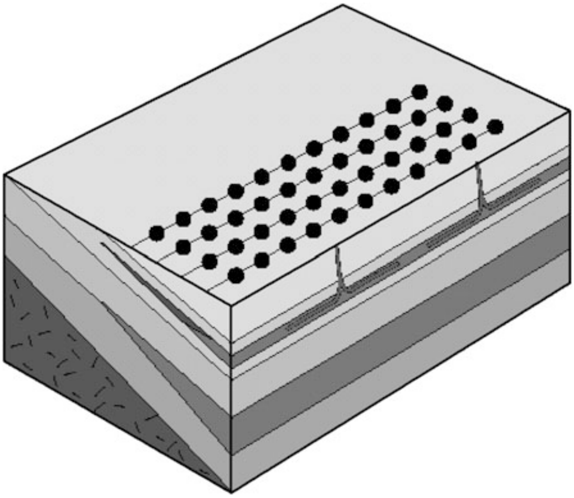


Fig. 7.9 A water-drive reservoir

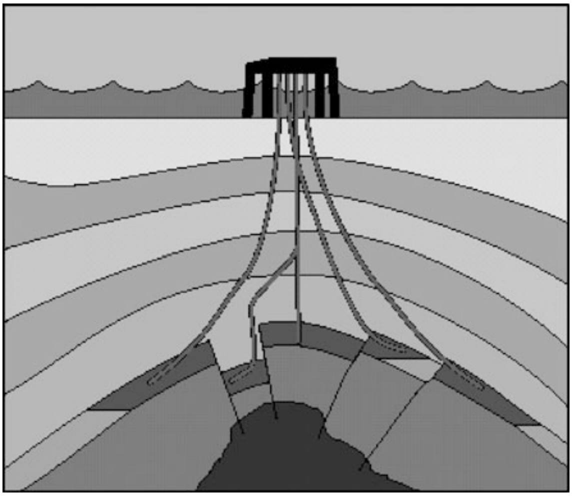


Fig. 7.10 Regions to be developed

m. Reservoirs in which normal well arrangement cannot be realized due to the surface factors. If a reservoir is located in a special geographical position, e.g., close to the town, main fields, rivers, and railways, the wells cannot be arranged normally due to the influence of cultural and environmental factors.

4. Well type and pattern of multilateral wells

The deployment of multilateral wells is closely related to the following factors: reservoir morphology, geological characteristics (reservoir distribution and sedimentary facies, etc.) reserves distribution, reservoir physical properties, fluid

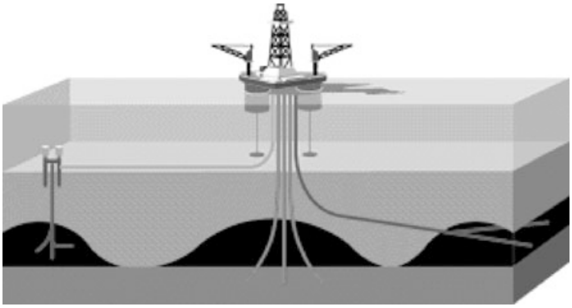


Fig. 7.11 Restriction of the offshore platform

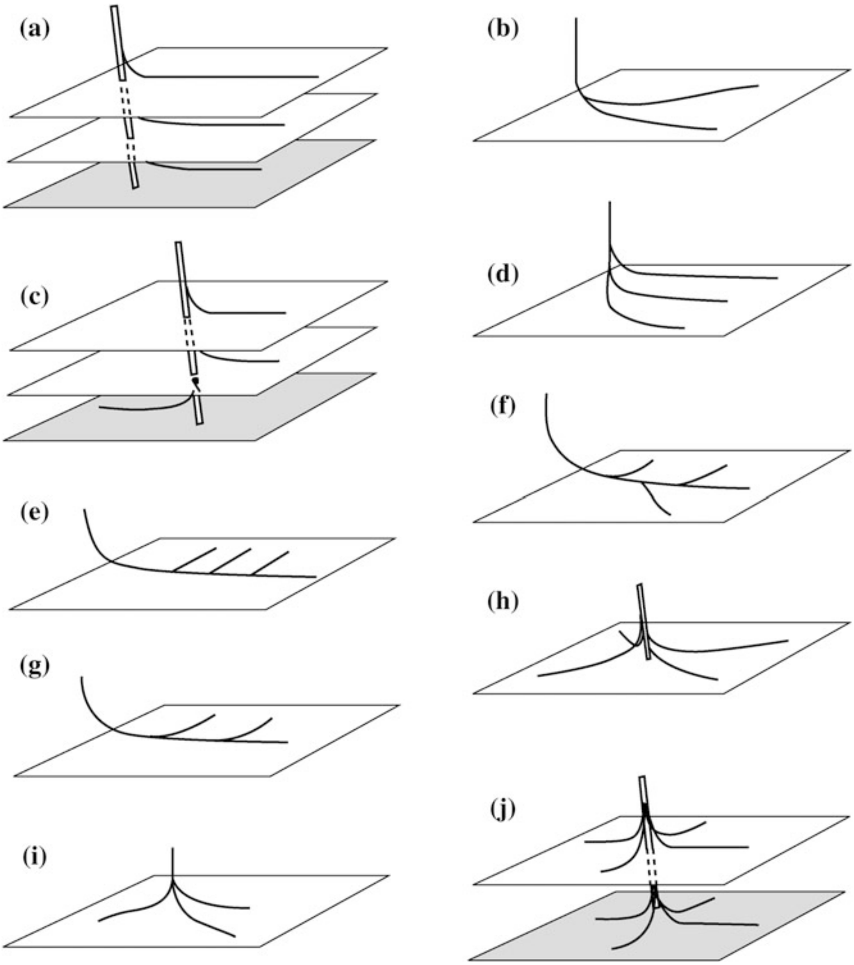


Fig. 7.12 Deployment patterns for different types of multilateral wells

characteristics, reservoir heterogeneity, etc. Different well types are suitable for different reservoir characteristics. According to the practice of the current oilfield development in China and other countries, the main well type is adopted for multilateral wells, as shown in Fig. 7.12. Altogether, there are 10 well types, in which types (a), (c), and (j) are more suitable for the multilayered reservoir, with types (a) and (c) for the reservoir with a main direction of permeability. Types (b), (d), (e), (f), (g), (h), and (i) are suitable for the single-layer thickness reservoir, and types (d), (e), and (g) are also suitable for the reservoir with a main direction of permeability.

7.2 Horizontal Wells and Well Pattern Optimal Design

7.2.1 Advantages and Adaptability of Horizontal Wells in Reservoir Development

1. The advantages of horizontal wells for reservoir development

Horizontal wells used for oilfield development have the following advantages: to increase reservoir openness degree, to increase the drainage area, to increase the single well production, and to reduce production cost. Therefore, this technology is widely applied to different types of reservoir development in China. In particular, it has the advantage in low-permeability reservoirs. Fishbone horizontal well development of low-permeability oilfield has been widely used in the world. The main advantages in performance are as follows.

a. Due to the high filtrational resistance of low-permeability reservoir, drawdown pressure is generally high. However, the near wellbore pressure drop of a horizontal well is lower than that of a vertical well and it is linear. A smaller differential pressure can be used for production to reduce gas breakthrough and water coning, delay the water breakthrough time, and improve the water flooding swept volume and ultimate recovery.
b. Horizontal wells can connect vertical fractures, increase production well permeability, and improve the oil production of low-permeability reservoir and oil production rate.
c. With horizontal wells, the single well control drainage area is large and the single well production is high, which can reduce the number of drilling well and realize a high production of sparse wells. With less investment and cost of concentrated production, the horizontal well is economically superior to the vertical well.

2. The main factors that affect the development effect of horizontal wells are as follows:

The main factors that influence the development effect of horizontal wells are as follows.

a. Vague geological understanding. The reservoirs which are characterized by simple structures, the single fault and the thick reservoir, and relatively stable reservoir distribution are an easy task for the application of horizontal wells. But due to insufficient geological understanding of the region and due to the complexity of the structures, people are unclear about the main layer and the reservoir distribution, which makes horizontal wells incapable of reaching the favorable areas and achieving the expected effect of increasing oil production.

b. Reservoir damage affects production well productivity. Because the area opened through horizontal well drilling is large and the operation time is long, reservoirs are vulnerable to damage, and the pollution is difficult to eliminate. Therefore, special attention should be paid to reservoir protection in the whole process of operation from the moment of opening the reservoir.
c. The magnitude of the stratum energy affects the productivity. Water injection is also needed to supplement energy in horizontal wells to maintain a stable production. At the initial stage of production, most horizontal wells have a high production, but it will decrease rapidly if water injection cannot keep pace with the production and the pressure drops dramatically. For horizontal wells, sufficient and appropriate water injection must be ensured just as it is done in the whole oilfield development.
d. The number of opened or fractured sections. To drill horizontal wells is to open more reservoirs to obtain a high production. A small number of perforated or fractured sections will be meaningless to drill horizontal wells.

3. The basic requirement of horizontal well developing reservoir

In order to get better efficiency, the basic requirements is given as follows when horizontal well be used to develop for the reservoir. Of course, if progress is made in some aspects of technology, some special reservoirs can be developed.

a. Reservoir buried depth: 1000–5500 m.
b. Reservoir thickness: More than 0.5 m, a single layer, good reservoir continuity.
c. The ratio of horizontal permeability and vertical permeability: The reservoir parameter $(h(k_h/k_v)-1)/2$ less than 100 m. Therefore, the reservoir cannot be too thick and the vertical permeability cannot be too low.
d. Formation coefficient: It should be more than 20 mD m. According to experience in some countries, if the reservoir formation coefficient is lower than 20 mD m, the horizontal well production in such a reservoir is not recommended except the reservoir formation with well-developed fracture.
e. Formation pressure: The ratio of the formation pressure to the reservoir initial pressure is higher than 0.5.
f. Crude oil viscosity: It should be less than 50 mPa s. Conventional water injection development can be used.
g. Single well recoverable reserves: The recoverable reserves are more than the economic limit of recoverable reserves and the oil drainage area is large enough.

Some reservoirs are not recommended for using the horizontal well production for example, the giant thick oil layer, multilayered reservoir, and thin scattered reservoir with poor continuity.

7.2.2 Design of the Horizontal Well Extending Direction

In the design of the horizontal well extending direction, we must take the reservoir characteristics and the direction of the well pattern deployment into consideration so as to achieve a high degree of water flooding control and effective water-drive direction in the process of production (Fig. 7.13). Generally speaking, the inherent directions of reservoirs consist of the following: the direction of the main permeability (the source direction, the direction of the main channel or the crack), the principal stress direction, the fracture direction (natural or artificial), the extension direction of sand bodies, the fault strike direction, the direction of the structural dip angle, and the direction of the edge water invasion. The pattern deployment directions consist of the following: the well line direction, the water-drive direction, the direction of horizontal well extension, etc. To achieve a favorable development effect, the reasonable well pattern deployment needs a harmonious coupling of the reservoir storage direction and artificial control direction. The inherent direction of the reservoir, together with the water-drive direction and the well line direction, should be taken into consideration in the design of the extending direction of horizontal wells. The following principles should be followed in the design.

a. The horizontal well extending direction should be perpendicular to the direction of the main permeation and intersect the sand body direction.
b. The horizontal well extending direction should be perpendicular to or forms an angle of 45° with the direction of the principal stress and the fracture direction.

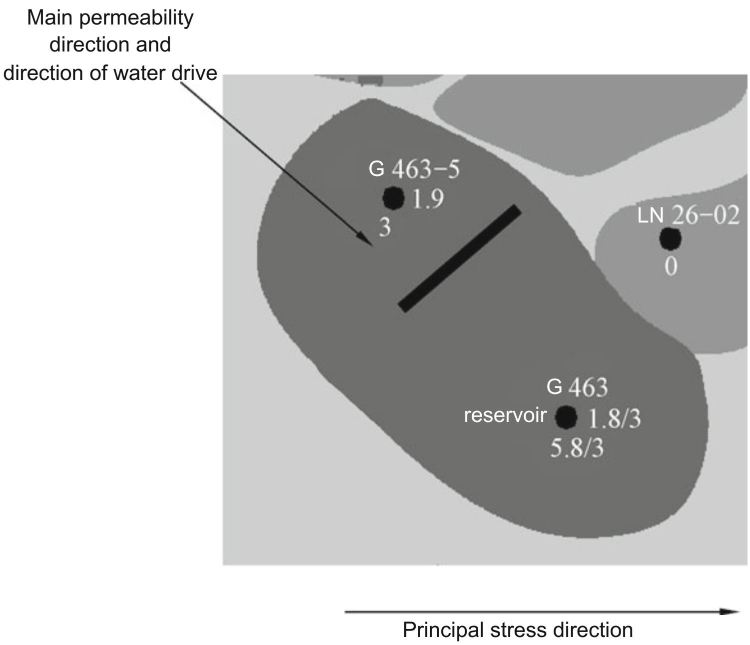


Fig. 7.13 Design of the horizontal well extending direction

c. When the direction of the main permeation is not consistent with the fracture direction, the former is taken as the main direction.
d. For the fracturing operation horizontal well, it is better that the water-drive direction is kept inconsistent with the fracture direction.
e. For edge water reservoirs, the direction of the edge water invasion should be vertical to the extending direction of the horizontal wells.

7.2.3 Design of the Length of the Horizontal Section

The length of horizontal section directly influences the oil drainage area of horizontal wells and controls the recoverable reserves. Ideally, the longer the horizontal section length is, the higher the horizontal well productivity will be. However, due to the constraints of the following factors, including the well pattern deployment, drilling technology, reservoir protection measures, reservoir characteristics, economic benefits, a longer length of the horizontal well is not necessarily better. So in the actual oilfield development and design, we can make an analysis from the following aspects.

1. Theoretical analysis and calculation of the length of the horizontal section

At present, people often use the formulas for calculating productivity of the horizontal wells derived by some foreign scholars such as Joshi, Giger, and Borisov, or the formula created by FAN Zifei et al. First, the vertical and horizontal productivity ratio is analyzed by means of theoretical formula of horizontal well productivity calculation and the calculation formula of vertical well productivity, and then the length of the horizontal section is optimized with the ratio. The calculation formula of the ratio of vertical well productivity to horizontal well productivity is obtained by means of Joshi's formula and the productivity formula of the vertical well:

$$\frac{q_{\mathrm{h}}}{q_{\mathrm{v}}} = \frac{\ln\frac{r_{\mathrm{ev}}}{r_{\mathrm{w}}}}{\ln\frac{a+\sqrt{a^2-(L/2)^2}}{L/2} + \frac{\beta h}{L}\times\ln\left(\frac{Lh}{2\pi r_{\mathrm{w}}}\right)}$$
$$a = \frac{L}{2}\left[0.5\left(0.25+\left(\frac{r_{\mathrm{eh}}}{L/2}\right)^4\right)^{0.5}\right]^{0.5},$$
$$r_{\mathrm{eh}} = \sqrt{\frac{\pi r_{\mathrm{ev}}^2 + 2L\cdot r_{\mathrm{ev}}}{\pi}},\ \beta = \sqrt{\frac{k_{\mathrm{h}}}{k_{\mathrm{v}}}} \tag{7.1}$$

where

q_h, q_v are the horizontal well productivity and vertical well productivity, respectively, m^3/d;
r_{ev} is the vertical well drainage radius, m;
r_w is the wellbore radius, m;
L is the horizontal well section length, m;
h is the reservoir thickness, m;
k_h, k_v are the horizontal permeability and vertical permeability, respectively, $10^{-3} \mu m^2$;
r_{eh} is the horizontal well drainage radius, m.

We can get the horizontal and vertical productivity ratio by means of Formula (7.1). Set the horizontal and vertical permeability ratio as 10. If the horizontal well drainage radius is converted from the square 250 × 250 m inverted nine-spot drainage radius (Fig. 7.14), we find that the horizontal and vertical productivity ratio increases with the increase of the horizontal section length, as in Fig. 7.15. In the actual well pattern deployment, horizontal wells are usually deployed in a limited area, and the area controlled by the horizontal well is also limited. If a single well controls the same area, the productivity ratios under the condition of different lengths can be obtained by calculating the drainage radius of the horizontal well with Formula (7.1), as shown in Fig. 7.16.

In general, the productivity formula of the horizontal well is deduced under the condition of infinity formation. Therefore, the longer the horizontal wells, the greater the productivity. Since the actual horizontal wells are deployed in a certain scope, the growth of production capacity will slow down when the horizontal length reaches a certain extent. Because the drainage area is unchanged, the second case is more realistic.

Another optimization method of the horizontal section length is numerical simulation analysis, with which a horizontal well can be designed to exploit a limited

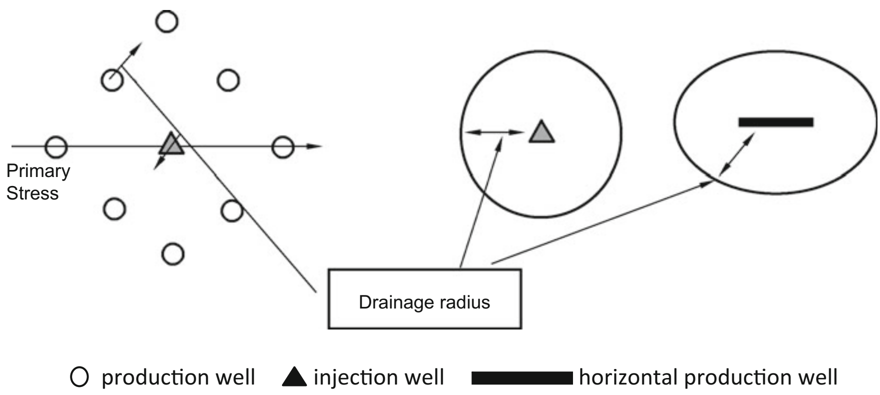


Fig. 7.14 Conversion of different drainage radiuses

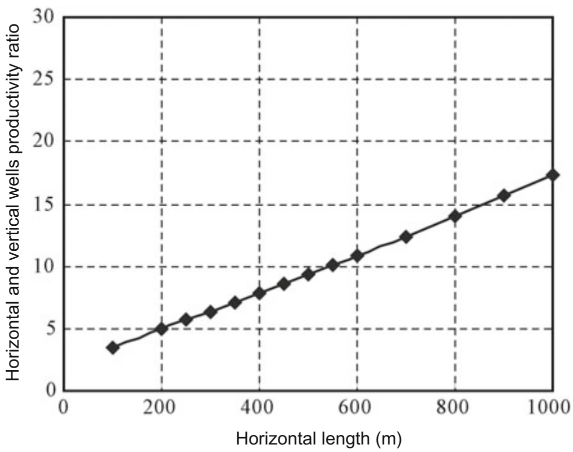


Fig. 7.15 Relationship of horizontal well length and capacity (converted drainage radius of vertical wells, Joshi's method)

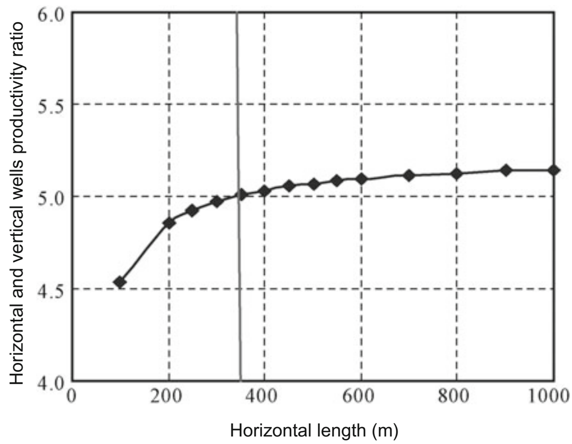


Fig. 7.16 Relationship of horizontal well length and capacity (converted drainage radius of the same control area, Joshi's method)

area. Suppose there is a rectangular reservoir of 1000 m × 1000 m with a horizontal well in the middle, the reservoir permeability is 15×10^{-3} μm^2, it is to produce oil with a constant pressure for 15 years, and the lengths of the horizontal section are 200, 300, 400, 500, 600, 800, and 1000 m, respectively, in different periods of time. Then, we can find the relationship between different lengths of the horizontal sections and the cumulative production through analog computation. In Fig. 7.17, after the length is greater than 600 m, the cumulative production increase slows down. It shows that the reasonable horizontal lengths are between 600 and 700 m.

2. Optimization based on economic analysis

According to the research by CHENG Linsong et al., the relationship between the horizontal section length and economic benefits is shown in Fig. 7.18. According to the variation of the curve in the graph, we can see that horizontal well lengths have

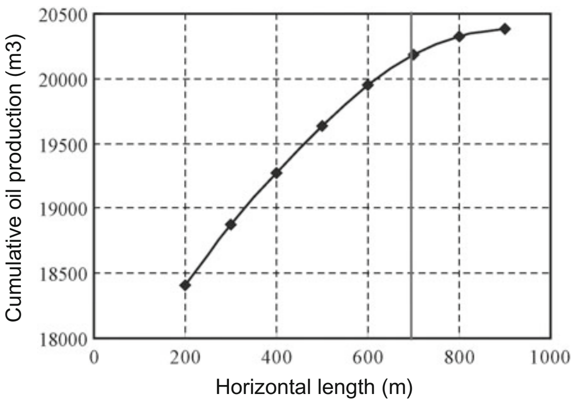


Fig. 7.17 Relationship between different horizontal well and cumulative production

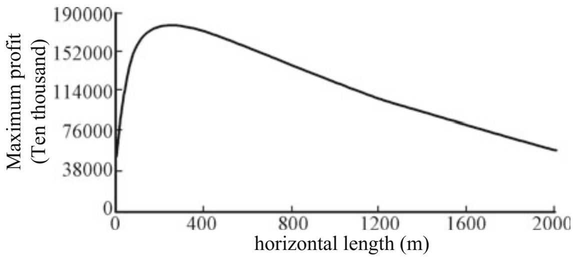


Fig. 7.18 Relationship between the horizontal well length and economic benefits

Table 7.2 Comparison of different lengths of the horizontal well in terms of economic benefits

Project	Row spacing: 300 m				Row spacing: 350 m			
	400 m	500 m	600 m	700 m	400 m	500 m	600 m	700 m
Internal rate of return (%)	10.18	10.86	15.35	15.71	6.14	8.15	11.15	13.45
Financial net present value (million *yuan*)	12.71	13.32	33.33	34.27	8.31	12.05	19.80	29.44
Dynamic payback (year)	6.65	6.42	4.62	4.48	9.15	7.95	6.05	4.52

a reasonable value, beyond which the economic benefits gradually decrease with the increase of the horizontal section length.

A calculation is made of the exploitation benefits of different lengths of the horizontal well in well lines according to the investment of horizontal wells in an oilfield in Table 7.2. The table shows the economic growth significantly diminishes when the lengths of the horizontal well are between 600 and 700 m. Based on an economic analysis, the horizontal well drilling reaches the oil sand body at about 300 m, and preferably the actual length is not more than 700 m.

3. Analysis and optimization of geological factors

Optimization of the length of the horizontal well is bound by the characteristics of reservoirs, and the adaptability of the reservoir must be taken into consideration. Main consideration is given to the restrictions of structure. Take the structure-controlled lithologic reservoir as an example. The width of the sand body is generally around 250 m and the maximum length is between 500 and 600 m. Most of them are potato-shaped sand bodies. If the horizontal well is drilled too long, many of them will remain a low drilling rate, which results in a high risk. Based on the distribution of sand bodies, the length of the horizontal section is preferably not too long.

Drilling technology's restriction on length: (1) If the horizontal well is too long, the drilling cycle will be very long and it will be prone to cause serious pollution, especially for low-permeability oilfields. (2) For low-permeability oilfields, reservoir reformation is required. The fracturing technology limits the length of the horizontal section of such reservoirs. The length of the horizontal well is preferably slightly longer than that of the segments to which staged fracturing can be applied to. For mid-high-permeability reservoirs with good properties, if there is no regional restrictions on the districts for well arrangement, the length of the horizontal well can be as long as possible. It will cause a high cost when the staged fracturing is implemented in low-permeability reservoirs. If horizontal wells are too long, it is difficult or even impossible to apply many underground technologies to them. Therefore, the horizontal well should not be extended too long.

In general, the length of the horizontal well in a low-permeability reservoir is about 300 m in China. A small portion of them reach the length of about 600 m. The average length of the horizontal wells in Zhaozhou Oilfield of Daqing Oilfield is 570 m. The length at which the oil sand bodies are drilled to is 312 m. Horizontal well development is employed on a large scale in low and extra-low-permeability reservoirs in Changqing Oilfield. With the progress of the technology of staged fracturing of horizontal wells in low-permeability reservoirs, the length of the horizontal section will gradually increase.

7.2.4 Design Principles for Spatial Location of Horizontal Wells

The design of the spatial position of horizontal wells mainly refers to the spatial position of the wellbore after the horizontal well has drilled to a reservoir, that is, the longitudinal position. The locations of reservoirs that are drilled to with horizontal wells are different due to different reservoir characteristics.

1. The location optimization of horizontal wells in the bottom water reservoir

The optimal vertical position of horizontal wells in the bottom water reservoir is closely related to its critical production and water breakthrough time. The critical

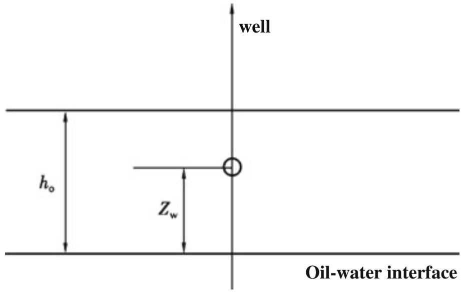


Fig. 7.19 Water-avoidance height of the bottom water-drive reservoir map

production of the bottom water reservoir horizontal well depends on average permeability, reservoir thickness, oil–water density difference, oil viscosity, and the vertical position of the horizontal well in the reservoir. It is generally considered that the farther the horizontal sections of the horizontal well are from the oil–water interface, the higher the critical production of the horizontal well is. But in fact, the closer the horizontal well is to the top of the reservoir, the greater the flow resistance of the horizontal well is in the bottom water reservoir and the lower the production capacity of the horizontal well is. Thus, there is an optimal location of horizontal sections of the horizontal well in bottom water reservoir. That can make the production effect best.

The location of the horizontal well in the bottom water reservoir has a greater impact on production and water cut. The closer it is to the top, the later the breakthrough occurs. Suppose it is closed above the ground, the boundary of oil–water is constant pressure and oil-feeding radius is infinity, as shown in Fig. 7.19.

where H_0 is the oil height, m;

Z_w is the distance between the horizontal section and oil–water interface, m.

Dimensionless well location $Z_0 = \frac{Z_w}{H_0}$

Formation horizontal and vertical permeability difference taken into consideration, the computational formula of critical production of the horizontal well in bottom water reservoir is given as:

$$\begin{aligned} q_o &= \frac{5.32 K_o L \Delta\rho_{wo} h_w / \mu_o B_o}{\ln \frac{4\beta h}{\pi r_w} + \ln \tan \frac{\pi h_w}{2h}} \\ \beta &= \sqrt{K_h / K_v}, \\ K_o &= \sqrt{K_h K_v} \end{aligned} \tag{7.2}$$

where K_o is the reservoir permeability, 10^{-3} μm^2;

K_h is the horizontal permeability, 10^{-3} μm^2;
K_v is the vertical permeability, 10^{-3} μm^2;
q_o is the horizontal well critical production, m^3/d;
$\Delta\rho_{wo}$ is the underground oil/water density difference, kg/m^3;
h_w is the distance from the oil–water interface to the horizontal wellbore, m;

μ_o is the crude oil viscosity, mPa s;
B_o is the crude oil volume factor;
h is the reservoir thickness, m;
r_w is the borehole radius of the horizontal well, m;
L is the length of the horizontal section, m.

To facilitate the research, define the dimensionless quantity,

$$\begin{aligned} q_D &= \frac{q_c \mu_o B_o}{5.32 K_v L \Delta\rho_{\mathrm{wo}} h_{\mathrm{w}}}, h_D = \frac{h_w}{h} \text{ then,} \\ q_D &= 1 \bigg/ \left(\ln \frac{4\beta h}{\pi r_w} + \ln \tan \frac{\pi h_D}{2} \right) \end{aligned} \tag{7.3}$$

where q_D is the critical production of the dimensionless horizontal well;
h_D is the vertical position of the dimensionless horizontal well.

Based on the calculation of Formula (7.3), a curve is drawn of the relationship between the dimensionless production of the horizontal well and the dimensionless vertical location of the horizontal well, as shown in Fig. 7.20.

As shown in Fig. 7.20 that when the ratio of the drawdown pressure to permeability anisotropy reaches a certain value, the horizontal well production decreases with the increase of the well location h_D; that is, the farther the horizontal well is from the oil–water interface, the smaller critical production of the horizontal well is. When the dimensionless distance $h_D < 0.2$ or $h_D > 0.9$, the horizontal well critical production declines rapidly with the increase of h_D, when the dimensionless distance is 0.2–0.9, and the horizontal well critical production changes more gently with the increase of h_D.

2. Position and structure optimization of the horizontal section

For the maximum use of reserves, in the design of the location, the horizontal section is designed to be parallel with the tectonic line of the target layer, which leads to a good development effect. With the numerical simulation method, the

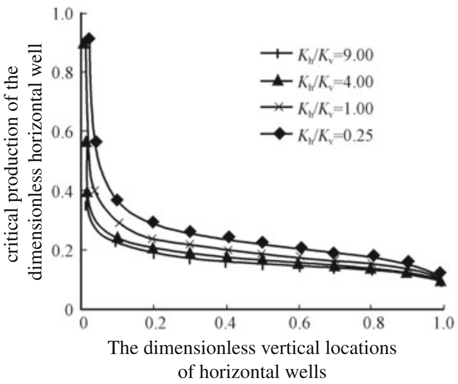


Fig. 7.20 Relation between the critical production of the horizontal well in the bottom water reservoir and the vertical position of the horizontal well

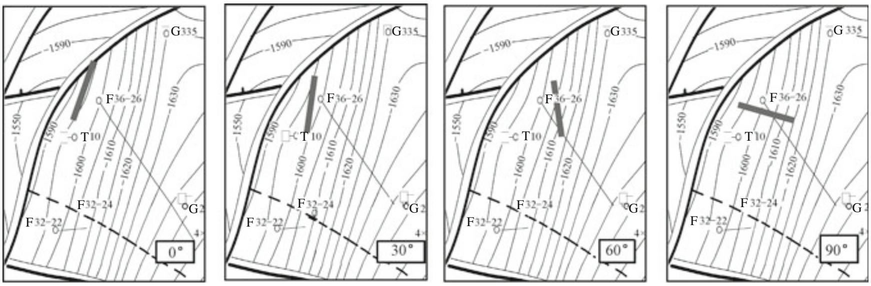
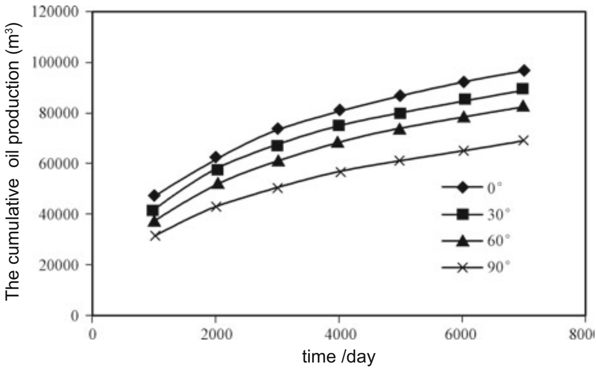


Fig. 7.21 Angles between the direction of the horizontal sections and the tectonic line

Fig. 7.22 Comparison of cumulative oil production under the condition of different angles formed by the horizontal section and the tectonic line



angles between the direction of the horizontal well and the tectonic line are set, respectively, as 0°, 30°, 60°, 90° for comparison (see Fig. 7.21).

From the results calculated in Fig. 7.22, we can see that when the direction of the horizontal well and the tectonic line forms an angle 0°, the best economic production life is 20 years, because in this case, the horizontal well can not only increase the oil volume, but also help to prevent the edge water tonguing so that a favorable development effect is obtained.

3. Horizontal well location optimization in general sandstone reservoirs

For general sandstone reservoirs, the production of horizontal wells is related to the permeability anisotropy and vertical permeability. The higher the ratio of vertical permeability k_v to horizontal permeability k_h, the higher the horizontal well production. Through the numerical simulation study, it is found that:

a. For conventional sandstone reservoirs, when $k_v/k_h < 0.2$, the best position of the horizontal well is in the middle of the reservoir.
b. For positive rhythm reservoir, the horizontal well position is located in the upper part of the reservoir, and its specific location depends on permeability differential ratio, the existence of the interlayer, and the size of the interlayer if it exists. The ratio of the area of the sandwich to the area controlled by the horizontal well is known as dimensionless area. When the interlayer range is

small, the development effect varies a little; when the dimensionless area is greater than 1, the recovery increases with the increase of the dimensionless area, and then gradually decreases; when the dimensionless area is 2.5, the change derivative of the recovery is the highest, and then gradually decreases; when the dimensionless area is more than 6, the increase magnitude of the recovery gradually declines and then keeps stable. Therefore, the analysis shows that, in the thick reservoir development, when the interlayer dimensionless area is greater than 6, a favorable development effect can be achieved with the horizontal well technology.

c. For an inverted layered reservoir, the horizontal well is located in the lower part of the reservoir, and its specific location depends on permeability, the existence of the interlayer, and the size of the interlayer if it exists.

7.2.5 Optimization of the Design Method of Horizontal Well Productivity

The design of horizontal well productivity is an important aspect of horizontal design. Due to the difference in the location of horizontal well drilling and deployment, the method of selecting the productivity calculation method should be different. In some countries, e.g., France's F.M. Giger and L.H. Reiss, and America's Renard and Dupuy et al., successively deduced the prediction formulas of horizontal well productivity in the early 1980s. In 1981, S.D. Joshi, an American scholar, reinfer the formula of horizontal well productivity by using the complex potential theory. The postulated conditions of the formulas are as follows: (1) steady flow, single-phase, incompressible fluid and isotropic homogeneous reservoirs, (2) without considering the formation damage, (3) the well is located at the center of the reservoir, (4) the drainage area is elliptical, and (5) the well has fracture for infinite conductivity and the flow pressure is constant at the bottom hole.

A typical productivity formula is as follows:

Joshi's formula:

$$q_{\mathrm{h}} = \frac{2\pi K_{\mathrm{h}} h}{\mu_{\mathrm{o}} B}\left[\frac{\Delta P}{\ln\frac{a+\sqrt{a^2-(L/2)^2}}{L/2} + \frac{h}{L}\ln\frac{h}{2\pi r_{\mathrm{w}}}}\right] \tag{7.4}$$

Borisov's formula:

$$q_{\mathrm{h}} = \frac{2\pi K_{\mathrm{h}} h}{\mu_{\mathrm{o}} B}\frac{\Delta P}{\ln\frac{4r_{\mathrm{eh}}}{L} + \frac{h}{L}\ln\frac{h}{2\pi r_{\mathrm{w}}}} \tag{7.5}$$

Giger's formula:

$$q_{\mathrm{h}}=\frac{2\pi K_{\mathrm{h}}h}{\mu_{\mathrm{o}}B}\left[\frac{\Delta P}{\ln\frac{1+\sqrt{1-[L/(2r_{\mathrm{eh}})]^2}}{L/(2r_{\mathrm{eh}})}+\frac{h}{L}\ln\frac{h}{2\pi r_{\mathrm{w}}}}\right] \tag{7.6}$$

Renard and Dupuy's formula:

$$q_{\mathrm{h}}=\frac{2\pi K_{\mathrm{h}}h}{\mu_{\mathrm{o}}B}\left[\frac{\Delta P}{\ln\frac{1+\sqrt{1-[L/(2a)]^2}}{L/(2a)}+\frac{h}{L}\ln\frac{h}{2\pi r_{\mathrm{w}}}}\right] \tag{7.7}$$

Joshi's was modified formula 7.1:

$$q_h=\frac{2\pi K_h h/\mu_o}{\ln\left(\frac{a+\sqrt{a^2-(L/2)^2}}{L/2}\right)+\beta\frac{h}{L}\ln\left(\frac{\beta h}{2\pi r_w}\right)}\cdot(P-P_{wf}) \tag{7.8}$$

Joshi's was modified formula 7.2:

$$q_h=\frac{0.534k_{\mathrm{h}}/(\mu B_{\mathrm{o}})}{\ln\left(\frac{a+\sqrt{a^2-(L/2)^2}}{L/2}\right)+\beta\frac{h}{L}\ln\left(\frac{\beta h}{2r_{\mathrm{w}}}\right)+256\,k\beta hB_{\mathrm{o}}\frac{L}{D^4}} \tag{7.9}$$

where

$$a=\frac{L}{2}\left[0.5\left(0.25+\left(\frac{r_{\mathrm{eh}}}{L/2}\right)^4\right)^{0.5}\right]^{0.5}$$

$$r_{\mathrm{eh}}=\sqrt{\frac{\pi r_{\mathrm{ev}}^2+2L\cdot r_{\mathrm{ev}}}{\pi}}$$

$$\beta=\sqrt{k_{\mathrm{h}}/k_{\mathrm{v}}}$$

In which

q_{h} is the production of the horizontal well, m^3/s;
K_{h} is horizontal permeability, 10^{-3} $\mu\mathrm{m}^2$;
h is the reservoir thickness, m;
B_{o} is the volume factor of reservoir oil, $\mathrm{m}^3/\mathrm{m}^3$;
μ is the fluid viscosity, mPa s;
L is the horizontal length of the horizontal well, m;
ΔP is the drawdown pressure, MPa;
a is half of the long axis of the ellipse, m;

r_w is the wellbore radius, m;
a is the long axis radius of the elliptical drainage area of the horizontal well, m;
r_{eh} is the drainage radius of the horizontal well, m;
r_{ev} is the drainage radius of the vertical wells, m;
D is the wellbore radius of the horizontal well, m.

In theory, horizontal well production increases infinitely as the length of the well increases infinitely. Actually, there is an ultimate length of the horizontal well. When the well is longer than the length, the production will decline due to friction loss or other pressure loss, and the above Formulas (7.4)–(7.8) do not take into the friction loss into account. For a reservoir with limited oil supply area, when the horizontal well is located in the limited area, the drainage area is taken as the capsule-type drainage area, as shown in Fig. 7.23. The horizontal well productivity Formula (7.10) is obtained through the derivation.

$$\begin{gathered} Q_h = \frac{2\pi KL(P_e - P_w)}{\mu_o B_o}\left(\frac{1}{L\ln\frac{R_e}{R_w}} + \frac{1}{\alpha - \pi} + \frac{1}{\beta - \pi}\right) \\ \alpha = \frac{\pi R_e}{H_l} + 2\ln\frac{H_l}{R_w},\ \beta = \frac{\pi R_e}{H - H_l} + 2\ln\frac{H - H_l}{R_w} \end{gathered} \tag{7.10}$$

In which

Q_h is the production well production (above ground value);
P_e is the supply pressure, 10^{-1}MPa;
P_w is the bottom hole pressure, 10^{-1}MPa;
K is the formation permeability, $10^{-3}\mu m^2$;
R_e is the supply radius, cm;
R_w is the well radius, cm;
B_o is the crude oil volume factor, m^3/m^3;
H is the reservoir thickness, cm;
H_l is the height of the horizontal section from the top, cm;
μ_o is the crude oil viscosity, mPa s;
L is the horizontal section length, cm.

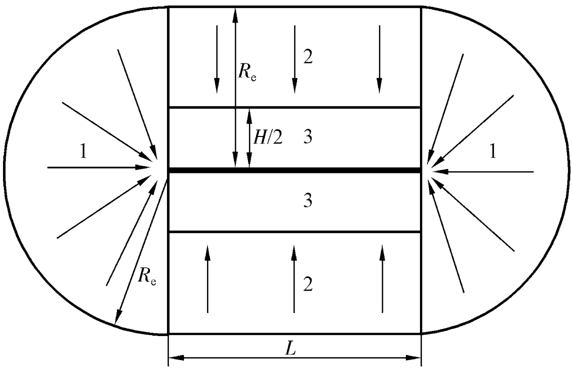


Fig. 7.23 Horizontal interface of the horizontal drainage area

Because the deployment areas and lengths of horizontal wells are different and so are the reservoir characteristics, an appropriate capacity calculation formula should be chosen. For an oval supply area in an infinite formation, the Formulas (7.4)–(7.8) can be used to calculate the output; for the capsule-type drainage area of the horizontal well, the Formula (7.10) should be chosen; if the horizontal well length is long or the friction along the horizontal section is strong, Formula (7.9) can be used. The above formulas are for a budgetary estimate of the capacity, and the actual deliverability can be worked out by combining the formulas with other methods such as numerical simulation analysis, comparison of similar kinds, and trial production analysis.

7.2.6 Principles and Methods for the Horizontal Well Pattern Design

1. The principles for the horizontal well pattern design

The horizontal well pattern is more complicated than the vertical well pattern, and there are many forms of horizontal well pattern, such as the exclusive horizontal well pattern, and the combination pattern of vertical and horizontal wells. Generally, the former consists of the row well pattern and the staggered well pattern which is suitable for well pattern of irregular reservoir characteristics; the latter consists of the five-spot well pattern with the vertical well for water injection and the horizontal well for production, the row well pattern, and the well pattern with the horizontal well pattern for water injection. The following principles should be followed in the actual deployment of the well patterns:

a. Economical and effective control of the geological reserves.
b. The water flooding direction is consistent with the main seepage direction.
c. The well pattern design is consistent with the reservoir characteristics and is harmoniously coupled with the reservoir directivity.
d. The overall deployment and the local well groups are harmoniously combined to adapt to different sedimentary facies and the heterogeneous characteristics.
e. It is helpful for the adjustment of the water flooding direction and the implementation of technology of enhanced oil recovery at the later stage of reservoir development.

On the basis of the above principles, different well patterns should be deployed according to different characteristics of reservoirs for the purpose of well pattern optimization. As shown in Fig. 7.24, it is a reservoir well pattern with a main fracture direction.

2. The methods for the well pattern design

   a. The reasonable supply radius is determined with the method of reservoir engineering. The limit control reserves and the corresponding control area of

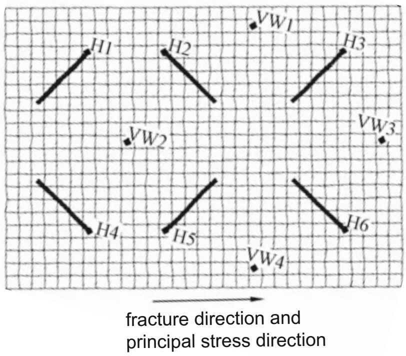


Fig. 7.24 Best well pattern for low-permeability fractured reservoirs

the horizontal well are determined with the economic evaluation method. Based on the two methods above, the limit control radius is determined.

b. The direction of water drive is designed according to the directional characteristics of the reservoir.
c. Based on the evaluation of the well pattern adaptability, a combination of different well patterns suitable for the reservoir is designed, a simulation combination is designed with the orthogonal experiment method, and the optimized well pattern is chosen with the numerical simulation method.
d. Based on different reasonable well patterns, the system parameters of the well patterns such as the reasonable injection-production ratio and injection-production well ratio are chosen according to the reservoir characteristics for the optimal control of the reservoir.

7.2.7 Design of the Horizontal Well Pattern

In China, there are not many reservoirs that are developed entirely with horizontal wells. They are used mainly as adjustment horizontal wells to improve the oilfield development effect at the later stage of development. The deployment and design of such horizontal wells currently rely mainly on the status of the development and residual oil distribution. The optimal design of the horizontal wells is made with the methods mentioned above with the results of fine understanding of reservoirs taken into consideration. In the process of the design, the reservoir characteristics, including sand body distribution, sedimentary facies, and reservoir direction, should also be fully considered. Furthermore, the advanced method of numerical simulation is used to optimize the modes, adaptability, and well pattern parameters of the well patterns so that the well patterns can match with the actual reservoir.

1. Horizontal parallel wells

The modes of parallel horizontal wells are described in Fig. 7.25, including the exclusive mode of horizontal production wells and the alternative mode of horizontal production wells and horizontal injection wells. Horizontal parallel wells are suited to reservoirs with a stable distribution, a large area and a distinct whole reservoir direction. The horizontal well extending direction should be vertical to the direction of the main seepage, which can obtain a high production. The mode of well pattern (b) in Fig. 7.25 shows that the water injection wells are parallel to the production wells. If the reservoir has favorable continuity, analog linear drive will be formed, which will greatly improve the efficiency of water flooding and the final results. This kind of wells can be used in heavy oil reservoirs that adopt steam injection drive or the technology of steam huff and puff.

2. The five-spot pattern of horizontal wells

The five-spot pattern of horizontal wells is shown in Fig. 7.26. According to different combination modes of production wells and water injection wells, they can be divided into: (a)—the inverted five-spot pattern of horizontal wells, (b)—the positive five-spot pattern of horizontal wells, (c)—the five-spot orthogonal pattern of horizontal wells, and (d)—the five-spot oblique pattern of horizontal wells. Their specific modes are shown in Fig. 7.26a–d. These well patterns are suitable for the reservoirs with the following characteristics: irregular reservoir distribution, poor extension, a large area, medium-sized distribution of sand bodies, and a distinct direction of the whole or part of the reservoir. In the figure, type (c) and type (d) are particularly suitable for reservoirs characterized by fracture. For a large reservoir where multiple horizontal well groups need to be arranged at the same time, type (a) and type (b) are similar in that they both constitute a staggered well pattern, that is, the five-spot pattern of horizontal wells in terms of well pattern arrangement.

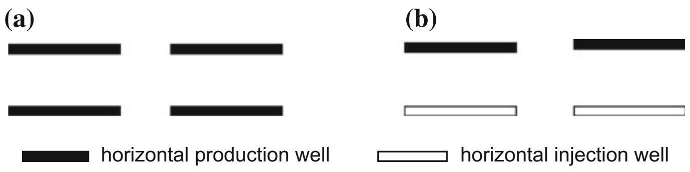


Fig. 7.25 Horizontal parallel wells

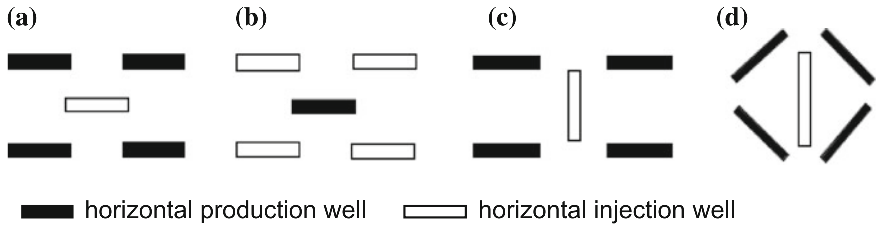


Fig. 7.26 Five-spot pattern of horizontal wells

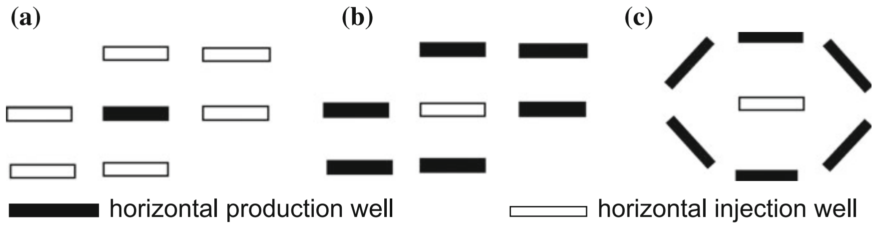


Fig. 7.27 Seven-spot pattern of horizontal wells

3. The seven-spot pattern of horizontal wells

The seven-spot pattern of horizontal wells is shown in Fig. 7.27. According to different combination modes of production wells and water injection wells, they can be divided into: (a)—the positive seven-spot pattern of horizontal wells, (b)—the inverted seven-spot pattern of horizontal wells, and (c)—the inverted seven-spot diamond pattern of horizontal wells. Their specific modes are shown in Fig. 7.27a–c. These well patterns are suitable for the reservoirs with the following characteristics: irregular reservoir distribution, poor extension, a large area, medium-sized distribution of sand bodies, and a distinct direction of the whole or part of the reservoir. They are also suitable for the reservoirs with poor permeability and low flow coefficient which need enhanced oil recovery.

4. The nine-spot pattern of horizontal wells

The nine-spot pattern of horizontal wells is shown in Fig. 7.28. According to different combination modes of production wells and water injection wells, they can be divided into: (a)—the inverted nine-spot pattern of horizontal wells, (b)—the positive nine-spot pattern of horizontal wells, (c)—the inverted nine-spot orthogonal pattern of horizontal wells, and (d)—the nine-spot orthogonal pattern of horizontal wells. Their specific modes are shown in Fig. 7.28a–d. These well patterns are suitable for the reservoirs with the following characteristics: irregular reservoir distribution, poor extension, a large area, medium-sized distribution of sand bodies, and the distinct direction of the whole or part of the reservoir. Among them, type (c) and type (d) are particularly suitable for reservoirs characterized by fracture. They are also suitable for the reservoirs with poor permeability and low flow coefficient which need enhanced recovery. For reservoirs characterized by

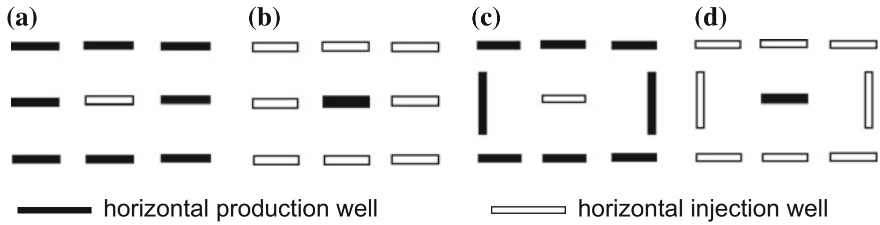


Fig. 7.28 Nine-spot pattern of horizontal wells

fracture, it is necessary to study how the well pattern direction reasonably couples with the fracture direction to get a favorable water flooding effect.

5. The combination pattern of horizontal and vertical wells

In most cases, the combination pattern of vertical wells and horizontal wells is used in China. There are two reasons for it. For one reason, it comes into being at the later stage of development, when the adjustment wells pattern are deployed by drilling horizontal wells on the basis of the original vertical wells pattern. For the other reason, due to the higher cost of drilling horizontal wells, injection wells are designed in the form of vertical wells. The combination pattern of horizontal and vertical wells mainly includes the following modes.

a. The row well pattern
   The row well pattern can be classified into four basic types, as shown in Fig. 7.29. The other types can be obtained from them through variation of combinations.

b. The combination of five-spot well pattern
   According to the reservoir characteristics and different combination types of horizontal well injection and horizontal well production, six basic combination types of horizontal wells and vertical wells can be composed, as shown in Fig. 7.30.
c. The combination of seven-spot well pattern
   Four types of the seven-spot well pattern are designed according to different conditions such as horizontal well water injection and vertical well water injection, as shown in Fig. 7.31. The angle and spacing can be adjusted according to the reservoir conditions in actual application.
d. The combination of nine-spot well pattern
   The seven-spot well pattern is designed into different combinations: the vertical injection wells plus the production well or the horizontal injection well plus vertical production wells, as shown in Fig. 7.32. The angle can be adjusted according to the reservoir conditions in actual application.

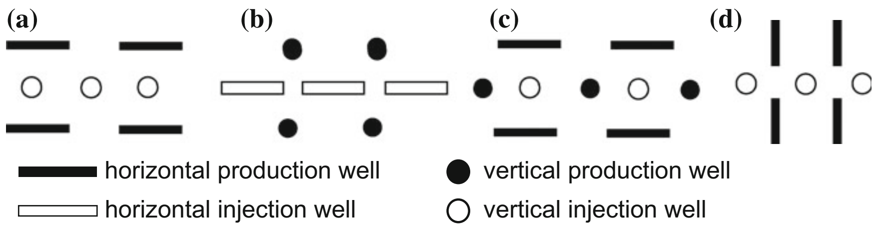


Fig. 7.29 Different combinations of row well patterns of the horizontal and vertical wells

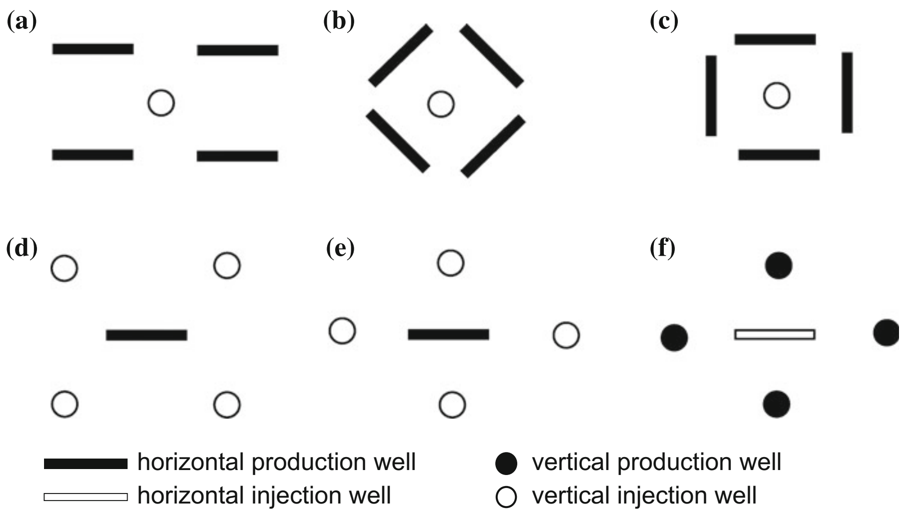


Fig. 7.30 Types of the five-spot well pattern formed by different combinations of horizontal wells and vertical wells

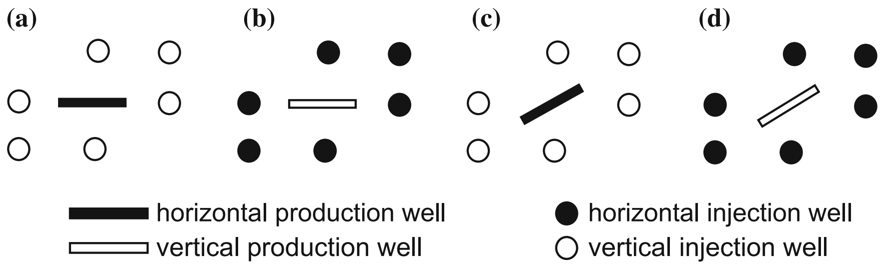


Fig. 7.31 Types of seven-spot well pattern formed by different combinations of horizontal wells and vertical wells

6. The horizontal stereoscopic well pattern
   The horizontal stereoscopic well pattern is determined according to special reservoirs. There are usually three modes. The first one is to use the auxiliary technology of SAGD in horizontal wells for viscous reservoirs, to be specific, a combination of the horizontal gas injection well with the horizontal production well, as shown in Fig. 7.33. It is suitable for the production of thick viscous reservoirs with the technology of steam huff and puff as well as steam drive. The second is longitudinal displacement method in extra-thick reservoirs to improve oil displacement efficiency by making use of the gravity of oil and water, as shown in Fig. 7.34. The third is to use selective zonal production of horizontal wells for multiple oil zones. As long as there are enough reserves, the oil can be extracted layer by layer, as shown in Fig. 7.35.

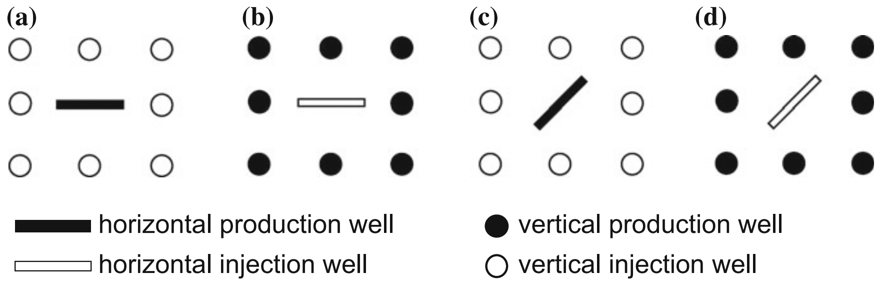


Fig. 7.32 Nine-spot well pattern formed by different combinations of horizontal wells and vertical wells

Fig. 7.33 Heavy oil reservoir

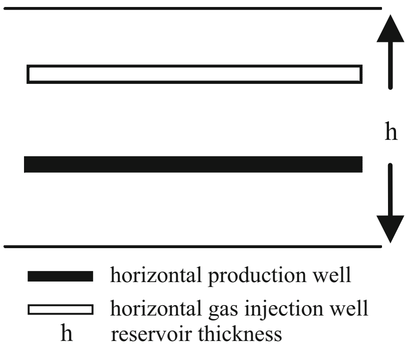


Fig. 7.34 Extra-thick reservoir

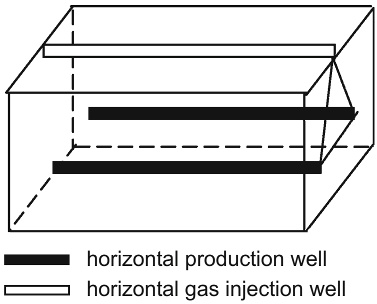
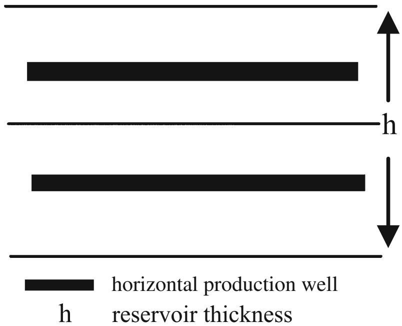


Fig. 7.35 Multiple oil layers



According to the simulation research and practical analysis, the degree of reserve recovery of the horizontal well pattern is higher than that of the vertical well pattern. Of them, the staggered row of the horizontal injector and producer ranks first, which is followed by the mode of the vertical injection well plus the horizontal production well and vertical production well. With the same well pattern, the degree of reserve recovery is higher when the horizontal well is used as a producer than when it is used as an injector. It is clear that the exclusive horizontal well pattern has more development advantages than the exclusive vertical well pattern.

7. Adaptability analysis of different modes of injection-production well patterns

   a. In a horizontal injection and horizontal production well pattern, the staggered combination is more effective than the combination of linear displacement, because in a staggered well pattern, the well section and the center of the adjacent well section overlap, as a result of which the swept volume is larger than that of the opposite type of well patterns.
   b. In the long-distance displacement with horizontal injection and horizontal production well pattern, the flood front tends to flow from the well heel of the injection well to that of the production well, and the pressure loss of the horizontal section and its sweep efficiency are seriously affected by the direction of liquid flow. Therefore, experts like Alex T. Turta recommend the inverted well pattern.
   c. In the short-distance displacement with horizontal injection and horizontal production well pattern, water breakthrough always happens at the well toe. It is recommended a mode of the short-radius horizontal well injection and the long-radius horizontal well production.
   d. Compared with the mode of horizontal well injection and vertical well production, the mode of vertical well production injection and horizontal well production can control the water injection velocity and vertical bottom hole pressure more easily, thus improving the sweep efficiency and increasing the recovery.
   e. Because the displacement method of vertical well production injection and horizontal well production has the advantages of reducing unfavorable mobility ratio and enhancing the water absorption capacity, its recovery is at least twice that of the conventional water flooding.

7.3 Well Pattern Optimal Design for the Fractured Low-Permeability Reservoir

Fractured low-permeability reservoirs mainly refer to those with primary fractures or recessive fractures (fractures that open when the injection pressure reaches a certain value). These fractures act as the main flow channels in the development process. The following is focused on the discussion of the fractured low-permeability sandstone reservoir, which has the following characteristics: (1) Reservoir matrix permeability is low, generally less than 10×10^{-3} μm^2, a typical feature of extra-low-permeability reservoir; (2) medium porosity; (3) large effective thickness and good extensibility; (4) well-developed natural fracture and obvious directivity.

The horizontal well development has become an important means to improve the degree of reserves control and the oilfield development effect. It is widely applied in many oilfields in China. According to adaptability of reservoirs, horizontal wells have been used as a major mode to increase the production well productivity and oilfield output in low-permeability and extra-low-permeability oilfields in Daqing and Changqing. But due to the different characteristics of different reservoirs, such as sedimentary micro-facies, permeability distribution characteristics, and different fracture distribution, the adaptability of horizontal wells and the mode and requirement of well pattern deployment may be very different. Therefore, it is necessary to study the optimization of the deployment mode of the horizontal development well pattern in extra-low-permeability sandstone reservoirs.

7.3.1 Design of the Vertical Well Pattern

1. The shortcomings of conventional well patterns

At the beginning of the low-permeability oilfield development, the areal well pattern is often adopted as is done in mid-high-permeability oilfields. In the process of development, there often appear the problems of inadaptability, mainly in the following several aspects:

a. The well production is low and decreases quickly. The natural production capacity of low-permeability reservoirs is very low, or even there is no natural capacity at all. Even if general fracturing production is adopted, its production capacity is also low, usually with a productivity index of only l–2 t/(MPa d). Because of poor reservoir connectivity and strong filtrational resistance of low permeable oilfields, usually the edge or bottom water is inert and the elastic energy is very weak. Except a small number of oilfields with abnormal pressure, the recovery is only 1–2 % at the elastic stage and it is not high even with dissolved gas drive, either. If natural energy is used for oil production, the well production will decline dramatically with the sharp drop of formation pressure, which results in passive production management.
b. Low water absorbing capacity and a slow effect of water injection. Not only does low-permeability reservoir have low water absorbing capacity, but also it requires a high pressure to start injection. The formation pressure near the injection wells rises up soon, and even the wellhead pressure and pump pressure reach a balance, which stops water absorption. Many oilfields have to shut the injection well or switch to intermittent water injection. Because low permeable

formation filtrational resistance is big, most of the energy is consumed around the injection wells and the water flooding effect is poor. Under the condition of 250–300 m well spacing, usually the water injection does not work until six months to one year later, after which the production well pressure and the output are relatively stable, with no obvious increase.

c. In the fractured low-permeability sandstone oilfield, water channeling and waterflooding of production wells are serious along the fracture direction. Due to the high water absorption capacity of injection wells of fractured low-permeability sandstone oilfield, channeling and water flooding of production wells are serious along the direction of fracture. In some oilfields, the adjacent wells will suffer violent water flooding a few days or even a few hours after an injection well is put into use. In most cases, the production wells and corresponding injection wells have to be abandoned once water flooding occurs. But fractures have a dual function. With proper adjustment and control, a better effect can also be achieved on development.

In order to solve the main problems in the development process, people have done a lot of research and exploration on the development well pattern and well type, such as the change of pattern modes, converting a vertical well into a horizontal well, which improves the development effect significantly.

2. The practice and understanding of the development well pattern

Scholars and engineers in both China and other countries have carried out extensive research on and field practice of development well pattern deployment optimization in fractured low-permeability reservoirs, from which they have accumulated some experience and learned some lessons. In China, for example, the inverted nine-spot well pattern is adopted in Shiyougou Oilfield of Yumen, the method of the well line intersecting the fracture direction with an angle of 22.5° and 45° is adopted in Linxin Oilfield of Jilin, and the inverted nine-spot well pattern (the well line intersects the natural fracture with an angle 22°) is used in Ansai Oilfield. The existence of natural fractures and artificial fracture system plays a dual role in reservoir water flooding development. On the one hand, it improves the water absorption ability of reservoir, makes up for the inadequacy of the reservoir permeability, and supplements formation energy with water injection. On the other hand, the underground natural micro-fractures are opened or the fractured fractures and natural micro-fractures help facilitate the connection between oil and water wells after water injection. As a result, some wells suffer a rapid water cut rise and water flooding, which affects the oil displacement effect of water injection and reduces the recovery of the reservoir. Therefore, micro-fracture and artificial fracture in the well pattern deployment is a very important factor to be considered.

Based on the development practice of a number of oilfields, we realize the key point of the reasonable vertical well pattern deployment that the reasonable well spacing in low-permeability oilfield development should be the unequally spaced linear injection well pattern. Then, we must first find out the following two key issues of well pattern deployment in the low-permeability oilfield development.

a. We must clearly recognize the fracture direction. Because even if there is only a small angle between the fracture direction and the well line direction, water channeling will occur because the spacing between the injection well lines is smaller than that between the production well lines in the unequally spaced linear injection well pattern arranged along the fracture direction. Therefore, the prerequisite for this kind of scheme of well deployment is to accurately find out the direction of the fractures (whether natural or fractured) before the well pattern deployment. There are a variety of methods for the determination of natural fracture direction, including geological method (structural analysis, outcrop survey, core observation, etc.), logging method (imaging logging, stratigraphic dip logging, dual caliper logging, etc.), and dynamic testing. The key to predicting the direction of hydro-fractured fractures is mainly to find out the ground stress direction in the current geological conditions. At present, there are many methods for the determination of ground stress direction, but they all have certain errors. Therefore, it is difficult for them to meet the requirements of the unequally spaced linear injection well pattern deployment. Accurate data should depend on an accurate analysis, in the perspective of rock mechanics, of the core collected by means of directional coring from the exploratory wells and appraisal wells. For the relatively new formations in the tertiary system and later, if there are no directional coring data, the core position is determined in the formation by utilizing the outcrop of the same formation and the paleomagnetic method, which is relatively accurate. In general, if natural fracture exists in the low-permeability oilfield, the direction of most of its hydro-fractured fractures (the maximum principal stress direction) is consistent with the natural fracture direction. They are different in very few cases.

The water injection should be operated with caution for such a reservoir, in which the natural fracture direction is not consistent with the fractured crack direction, the natural fracture direction is uncertain, or the natural fracture system is complicated. For this type of oilfield, generally, exploitation by using natural energy is the first choice, and the well pattern should be arranged according to the specific situation.

b. The ratio of the matrix permeability to the fracture permeability must be identified, because the well spacing and row spacing of unequally spaced linear injection well patterns mainly depends on it. Therefore, optimal fracturing design should be made in consideration of the production well productivity, reservoir buried depth, reservoir and interlayer distribution, and reservoir matrix permeability (including the natural fracture permeability value). Based on the optimal fracturing design, the ratio of matrix permeability to fracture permeability can be determined.

3. The design and evolution of actual well patterns

At the beginning of the low-permeability oilfield development, the areal well pattern is often adopted as is done in mid-high-permeability oilfields. In the process of development, it mainly includes the five-spot well pattern, the inverted nine-spot well pattern, and the row well pattern. Because the natural fractures play a leading role to fluid flow in the development process and the fracture system is used unreasonably, water channeling will soon appear. Generally, the natural production is low in low-permeability oilfields. They need fracturing operation to get relatively high production, and the injection-production well should be reasonably designed to match the existence of fracturing fractures. Several main factors must be considered in the design process of well pattern design: the fracture orientation, the direction of fracturing fractures (the principal stress direction), the main seepage direction, the well line direction, and the direction of water flooding, etc.

In Fig. 7.36, there are three kinds of well pattern. (a) is the square nine-spot pattern with the following characteristics. In the blocks with well-developed fracture, if the area between the injection well and production well is in the direction of or close to the direction of fracture, then the flow resistance is small, the effective driving distance is far greater than the well spacing, the well is quick to come into effect, and water cut rises fast due to the function of fracture. In contrast, if the area between the wells is perpendicular or nearly perpendicular to the fracture direction, then the flow resistance is big, the well effect is poor, the degree of water flooding recovery is low, the production well's liquid producing capacity is low, and its exploitation effect is also inevitably bad. In low sandstone permeability reservoirs, due to the existence of fractures, the permeability parallel to the principal stress direction is dozens of or even hundreds of times higher than that in other directions. Under the condition of such a large plane permeability differential, if the regular square pattern system is adopted, it is difficult to solve the problem of quick directional breakthrough and water flooding in permeability anisotropy reservoirs. It is proved that the problem of quick water flooding of the wells (especially the wells in the corner of the pattern) on the fracture cannot be solved with the square well pattern. The actual development effect of this kind of well pattern is bad, because water flooding occurs too soon in the wells in the fracture direction. Through exploration practice, two kinds of well pattern, i.e., (b) and (c), are designed, whose purpose is to delay water breakthrough by increasing the interwell distance along the

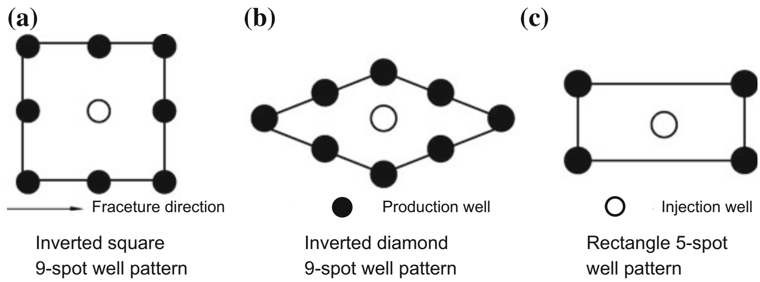


Fig. 7.36 Design of different well patterns

fracture direction and shortening the inter-row distance to improve the water flooding effect. This pattern has a better development effect in practice.

Inverted nine-spot diamond well pattern is shown in Fig. 7.36b. It is adopted in blocks with well-developed fracture, because the diamond's long diagonal is parallel to the direction of the maximum principal stress, which can delay the water flooding of the wells in the corner and increase the effect of the wells on the edge. Besides, with the increase of the well spacing in the fracture direction, the fracturing scale and the artificial fracture length will also increase, which can improve the single well production and initial production rate. It has two adjustable row directions, which are suitable both for the operation at the beginning of the block development and for the adjustment of the well line direction according to the fracture direction at the late stage. With this pattern, the injection well line can be converted to production wells when the production wells are flooded to form a well pattern of two rows of injectors with two rows of producers in between.

The five-spot rectangular well pattern (Fig. 7.36c). It is a development mode of enhanced injection and enhanced recovery used in blocks with well-developed fracture. The direction of the injection well line is consistent with the fracture direction so that the water flooding problem of the production wells along the fracture direction is avoided. Its actual mode is staggered rows of water injection, in which the well spacing is increased, the distance between the well lines is shortened, and the fracture drainage channel water flooding is formed. As a result, the actual linear flow or linear displacement is formed, which has a good effect of water flooding. In the actual process, the fracturing scale can be expanded and different production well lines and injection well lines form their respective linear drainage channels, which greatly increases production.

4. The basic principles and implementation steps for the reasonable placement of the water injection development well pattern in fractured sandstone oilfields

On the basis of practical experience and theoretical research and according to the structural characteristics of the fractured sandstone oilfield reservoir, the basic principle for the water flooding development well pattern deployment in a fractured sandstone oilfield is "the well array of flexible well line spacing along the fracture direction," which includes the following three points specifically:

The well line direction, especially the injection well line direction, should be parallel to the fracture development direction, and the water flooding direction should be perpendicular to the fracture direction. In this way, the water channeling into the production wells and violent water flooding can be avoided to improve the effect of water flooding.

The injection well spacing can be appropriately increased to the length greater than the spacing between the injection well line and production well line. This can give full play to the advantages of high water absorbing capacity of the fractured reservoir, and at the same time increase the driving pressure gradient between the injector-producer rows so as to improve the development effect. In the beginning, every other well is used for injection. Then, after the waterline is formed, the drainage wells are gradually converted into injection wells (the second patch of injection wells).

At the early stage, the production well spacing can be the same as the injection well spacing in the stagger arrangement. At the middle stage, infill adjustment wells can be drilled at the production well line according to the actual situations to expand the sweep volume of the injected water to prolong the stable production years of an oilfield and to improve the ultimate recovery of crude oil.

According to the above basic principles, assuming the fracture direction of an oilfield reservoir to be an east–west direction, its specific implementation steps of the well pattern arrangement are as follows.

The first step is to arrange the wells in parallel with the fracture direction. To begin with, it is necessary to determine the two parameters:

a. Well spacing. It is determined mainly according to the fracture permeability. Generally, the higher the fracture permeability is, the bigger the well spacing should be. Otherwise, the well spacing should be narrowed. In the beginning, the production well spacing and the injection well spacing are the same. At the middle or late stage, infill adjustment wells should be considered.
b. Row spacing. It is determined according to the matrix permeability and fracture density (i.e., the number of fractures per unit length perpendicular to the fracture direction). In general, the lower the matrix permeability is and the smaller the fracture density is, the smaller the row spacing should be. Otherwise, it should be increased.

To sum up, the well pattern deployment in the fractured sand (gravel) oilfield, whose matrix material is mainly low permeable formation, can be summarized as the following specific principles. If the direction of the well arrangement is parallel to the main direction of the fractures and the linear water injection is adopted, the well spacing can be increased and the row spacing should be shortened. But in the deployment of injection wells, the injection well line direction in the five-spot system should be in the same direction of the maximum principal stress as far as possible. This is the principle for the deployment or adjustment of the injection-production system.

According to China's actual situations of the fractured and low-permeability sand (gravel) oilfields, the following combinations of well pattern deployment are recommended (see Table 7.3).

It should be pointed out that in the study of the well pattern deployment, preliminary consideration has already been given to the function and effect of the fracturing technology.

Of course, factors such as reserves abundance and reservoir depth should also be taken into consideration in a specific development well pattern scheme of an oilfield. Detailed technical and economic evaluation should be made with the economic benefits focused on.

Table 7.3 Reference table of the well deployment in a low-permeability and fractured sandstone (gravel) oilfield

Matrix characteristics	Combination of well patterns	No fractures	Micro-fracture	Small fractures	Medium-to-big fractures
		Well spacing = 1 row spacing	Well spacing = 2 well spacings	Well spacing = 3 well spacings	Well spacing = 4 well spacings
Super-low permeability	Well line (m)	120	120	120	120
	Well spacing (m)	120	240	360	480
	Well spacing density (number of wells/km^2)	69	34	23	17
Extra-low permeability	Well line (m)	150	150	150	150
	Well spacing (m)	150	300	450	600
	Well spacing density (number of wells/km^2)	44	22	14	11
Relative-low permeability	Well line (m)	170	170	170	170
	Well spacing (m)	170	340	510	680
	Well spacing density (number of wells/km^2)	34	17	11	8.7
Common-low permeability	Well line (m)	200	200	200	200
	Well spacing (m)	200	400	600	800
	Well spacing density (number of wells/km^2)	25	12	8.3	6.2
Medium-low permeability	Well line (m)	250	250	250	250
	Well spacing (m)	250	500	750	1000
	Well spacing density (number of wells/km^2)	16	8	5.3	4

The second step is to put the injection wells into use in two batches: (1) initial injection wells and (2) the injection wells converted from the drainage wells. When the first batch of injection wells is working, the second batch of injection wells converted from the drainage wells can be used to appropriately amplify the differential pressure in the production to help from the waterline. After the drainage wells are flooded, they should be converted into injection wells to constitute a linear injection pattern.

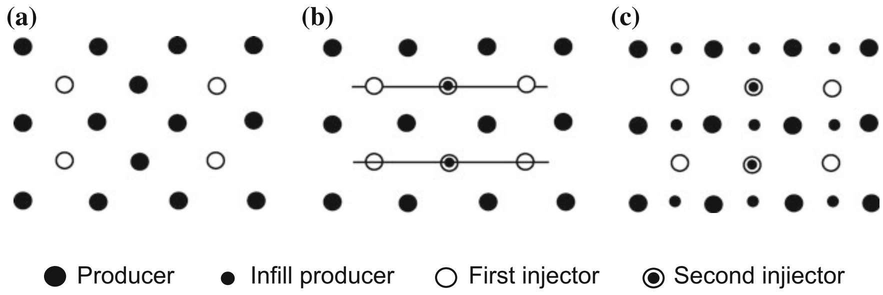


Fig. 7.37 Deployment of well patterns parallel to the fracture direction

The third step is as follows: In the beginning, the producing wells' drawdown pressure should be properly controlled. When the drainage wells are converted into injection wells, the drawdown pressure can be increased in order to make up for the loss of the drainage wells' production before the conversion and keep the stable production of the whole oilfield. When the production well drawdown pressure cannot be enlarged continuously or the rise of the production well water cut affects the whole oilfield production, research should be done to slow down the production reduction magnitude, improve the development effect, and increase the ultimate recovery of crude oil. Economic calculation and evaluation of the adjustment scheme are necessary to make the final decision with economic benefits as the center.

The deployment patterns according to the above ways are shown in Fig. 7.37. In the figure, (a) refers to the well pattern at the early stage, (b) refers to the well pattern with the second batch of injection wells (those converted), and (c) refers to the well pattern after the infill wells are drilled.

4. The elements that need to be paid attention to in the design of the well pattern

   a. To fully recognize the directional characteristics of reservoirs, mainly including the fracture direction, the principal stress direction, and the main seepage direction.
   b. To reasonably control the fracturing scale and be clear about the trend of the hydro-fractured fractures.
   c. To choose the appropriate diamond well pattern and harmoniously couple the direction of injection well line with the reservoir direction.
   d. The well pattern deployment should be convenient for the well pattern adjustment at the late stage.

7.3.2 Design of the Horizontal Well Pattern

Because the vertical well production is low and decreases fast, some low-permeability oilfields have bad development effect and economic benefits. Now horizontal wells are successfully used in many oilfields for the development of low-permeability reservoirs in China. In particular, the progress and breakthrough in horizontal well-staged fracturing technology greatly improve the effect of horizontal well development. Currently, horizontal wells are used on a large scale for the development of low-permeability reservoirs in Changqing Oilfield, Jilin Oilfield, etc.

Facts show that in extra-low-permeability reservoirs, if horizontal sections are perpendicular to the maximum principal stress direction, coupled with the multi-spot fracturing technology, it can greatly improve the seepage ability, thus improving the production. In the horizontal well pattern design, the vertical wells can meet the basic requirements of injection in low-permeability oilfields. Therefore, it is not common to adopt horizontal well patterns exclusively. In most cases, a combination pattern of vertical and horizontal wells is used. When a specific well pattern design is made, the following points should be paid attention to: (1) the horizontal extension direction, (2) the fracture direction and the principal stress direction, and (3) the injection well line direction and the direction of water flooding.

1. The design of horizontal injection-production well pattern

Generally, it is not common for a low-permeability oilfield to adopt the horizontal well exclusively because of the high cost of drilling a horizontal well for water flooding. In actual oilfield application, we can use the five-spot well pattern as shown in Fig. 7.26, especially (c) the five-spot orthogonal horizontal well pattern, (d) the five-spot oblique horizontal well pattern, and (c) in Fig. 7.27 the inverted seven-spot diamond horizontal well pattern.

Figure 7.38 shows two horizontal well patterns, which can obtain good development effect if coupled with fracturing technology. In Fig. 7.38a is a parallel staggered horizontal well pattern, suitable for reservoirs with good continuity. Pulling the waterline to form quasi-linear displacement can greatly improve the water flooding efficiency and ultimate recovery. In Fig. 7.38b is an orthogonal staggered horizontal well pattern. Through staged fracturing in the principal stress direction, this well pattern can increase the seepage ability significantly to establish a normal displacement system, thus increasing the well production.

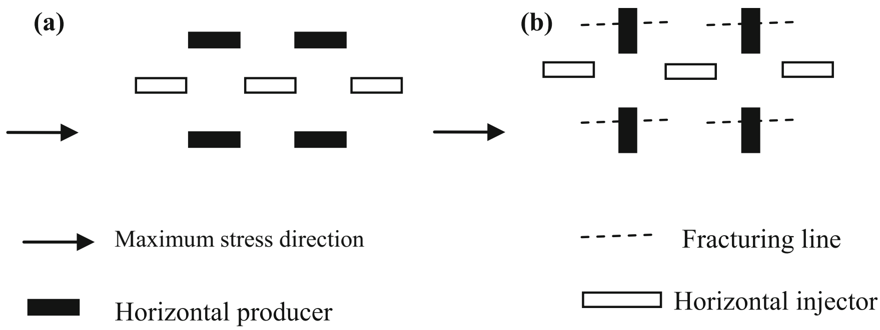


Fig. 7.38 Horizontal well pattern in a low-permeability oilfield

In the low-permeability oilfield development, other horizontal well patterns presented in Chap. 2 are not suitable for low-permeability fractured reservoirs.

2. The design of the horizontal and vertical well combination pattern

The combination of vertical and horizontal well pattern is commonly used in the development of fractured low-permeability reservoirs, which obtains good results in actual field application. Due to various factors such as the fracture direction and reservoir characteristics, the modes of its well pattern vary to some extent. Different modes have their own characteristics and advantages.

Through production practice, people realize that the row well pattern and the five-spot well pattern are more suitable for the development of the fractured low-permeability reservoir. The details are as follows.

a. The row well pattern

The row well pattern is a combination of the horizontal wells and vertical wells according to the reservoir characteristics when the vertical well is used as an injection well or production well, and the horizontal well is used as a production well or an injection well. Its four basic modes are shown in Fig. 7.39. The other modes can be created through the combination or transformation of the four basic modes.

b. The five-spot well pattern

According to the reservoir characteristics and different modes such as horizontal well injection or horizontal well production, four basic well patterns with the horizontal well and vertical well combined can be designed, as shown in Fig. 7.40.

The fracture direction and the direction of hydro-fractured fractures must be considered when the above patterns are applied. It is essential that the waterline along the fracture direction not be vertical to the production well line.

c. The combination modes' optimization of the vertical and horizontal well patterns

In the process of actual oilfield development, different modes of well patterns are needed due to the differences in reservoir characteristics, fluid property, formation of pressure system, and production strategy. The well pattern design is influenced

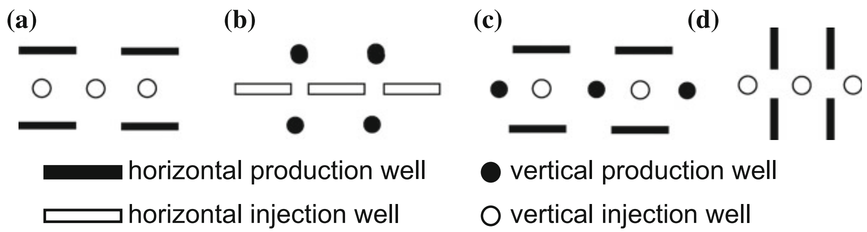


Fig. 7.39 Different combinations of horizontal well patterns and vertical well patterns suitable for fractured low-permeability reservoirs

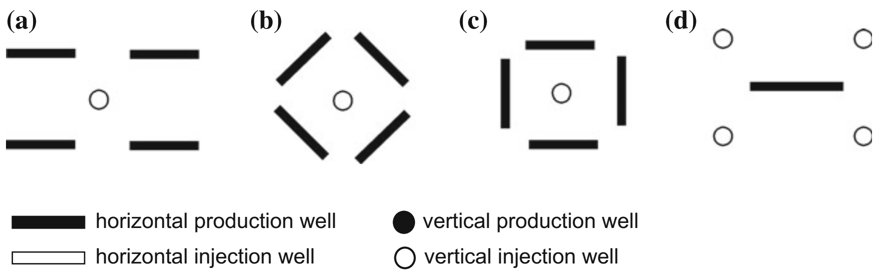


Fig. 7.40 Five-spot well patterns with the horizontal well and vertical well combined

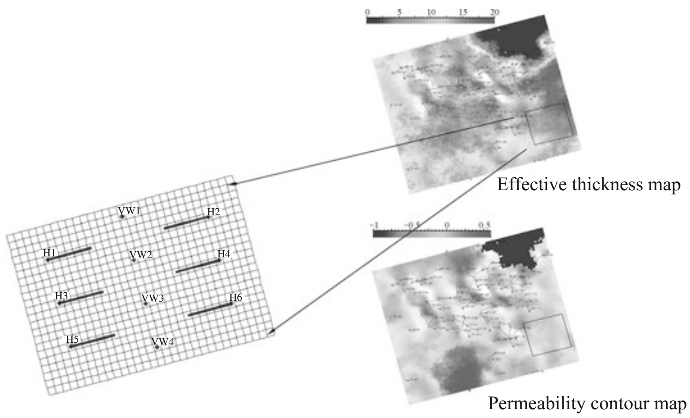


Fig. 7.41 Area of the horizontal well optimization model

by the following factors: different combination modes of well patterns, well pattern parameters (well spacing, row spacing, injection-to-production-well ratio, well spacing density, etc.), and the way of maintaining and supplementing energy. Here is a research on the mode optimization of well patterns in a low-permeability fractured reservoir.

This is a case study of the geological model of Chang 4 + 52 reservoir of Y48 well block in CQ Oilfield. A favorable area with high porosity and permeability reservoirs is chosen for the horizontal well deployment (Fig. 7.41). Its size is 1.7 km^2, its geological reserves are 78.74×10^4 t, and its grid nodes are $31 \times 22 \times 1 = 682$.

a. Well pattern design

According to the size of the selected area, reservoir fracture characteristics, etc., and based on the design principles for the horizontal well and reservoir adaptability mentioned above, the horizontal well pattern is designed with a certain ratio of vertical wells to horizontal wells. The design consists of seven types and fifteen schemes, including the vertical well pattern, the horizontal well pattern, and the combination of the two. An optimal mode of development well pattern is selected through the calculation of development dynamic by means of numerical simulation and through economic analysis. Detailed descriptions are shown in Tables 7.4 and 7.5. The corresponding well patterns are shown in Figs. 7.42, 7.43, 7.44, 7.45, 7.46, 7.47 and 7.48.

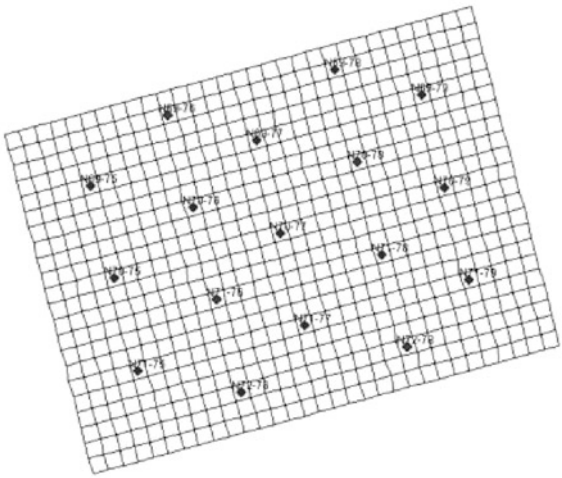
Table 7.4 Schemes of the basic well pattern deployment

Names of schemes		Number of production wells		Number of injection wells		Scheme description
		Vertical well	Horizontal well	Vertical well	Horizontal well	
Basic well patterns	Inverted nine-spot diamond well pattern	13		3		The inverted nine-spot diamond for 550 m × 150 m well pattern deployment in the selected area
	Unequally spaced linear injection well pattern	12		6		The unequally spaced linear injection for 450 m × 150 m well pattern deployment in the selected area
	Scheme 1		6	3		The producers (horizontal) are parallel to the fracture direction and the injectors (vertical) are perpendicular to it
	Scheme 2		6	3		The producers (horizontal) are perpendicular to the fracture direction and the injectors (vertical) are parallel to it
	Scheme 3		6		2	Both the producers and the injectors are horizontal wells and the well line is parallel to the fracture direction
	Scheme 4		6		2	Both the producers and the injectors are horizontal wells. The producers are perpendicular to the fracture direction and the injectors are parallel to it.
	Scheme 5		6	2.5		The horizontal section direction and the fracture direction form an angle of 45°

Table 7.5 Schemes of the supplementary well pattern deployment

Names of schemes		Number of production wells	Number of injection wells		Scheme description
		Horizontal well	Vertical well	Horizontal well	
Improved well patterns	Scheme 1-1	6	4		According to the research based on the basic schemes, supplementary vertical or horizontal injection wells are drilled where there is plenty of remaining oil. The specific well locations are shown in the Figs. 7.49, 7.50, 7.51, 7.52, 7.53, 7.54, 7.55 and 7.56
	Scheme 2-1	6	6		
	Scheme 2-2	6	3		
	Scheme 3-1	6		3	
	Scheme 3-2	6	1	2	
	Scheme 4-1	6	2	2	
	Scheme 4-2	6	1	2	
	Scheme 5-1	6	3		

Fig. 7.42 Inverted nine-spot diamond well pattern



b. Determination of fracture conductivity

For the sake of good fitting dynamic simulation and the selection of fracturing fractures, the injection wells which are not affected by the production well (Xin 65–68 wells) are used to build a single well model. The conductivity of the injection wells are calculated through the fitting injection rate. The simulation results show that the fracture effective permeability is 30–60 times as high as the reservoir permeability. The next step is to calculate the conductivity of the injection wells

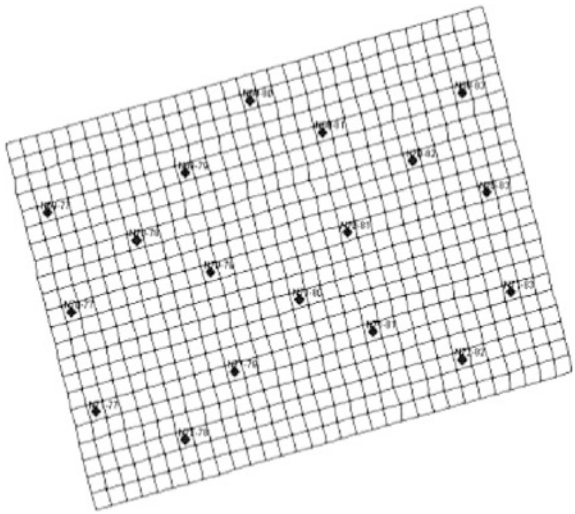


Fig. 7.43 Unequally spaced linear injectors

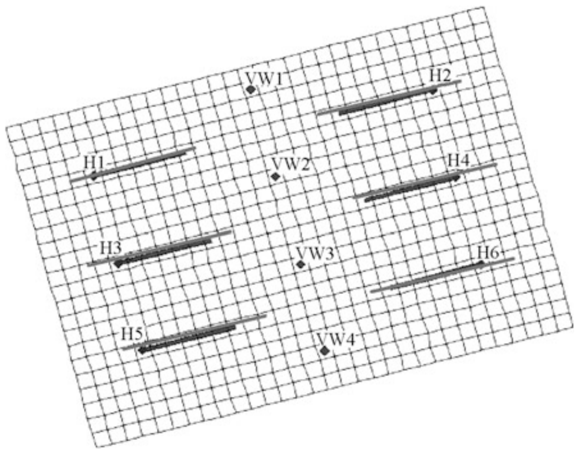


Fig. 7.44 Scheme 1

through the local grid refinement and the fitting injection rate. The simulation results show that the fracture effective permeability is 33 times as high as the reservoir permeability.

c. The specific selection of combination mode of well pattern between horizontal and vertical wells

According to different modes of well patterns, the reasonable injection-production pressure system, injection-production parameter, and working system of oil–water

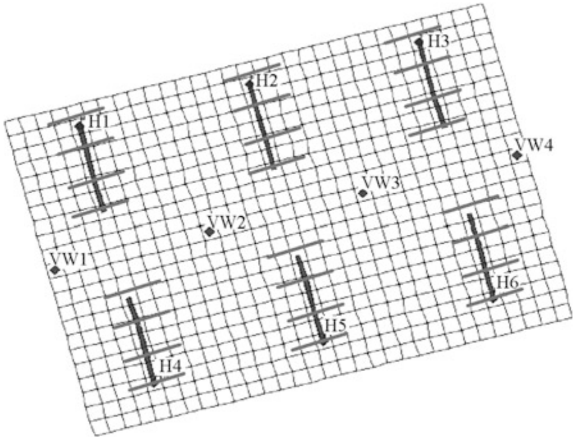


Fig. 7.45 Scheme 2

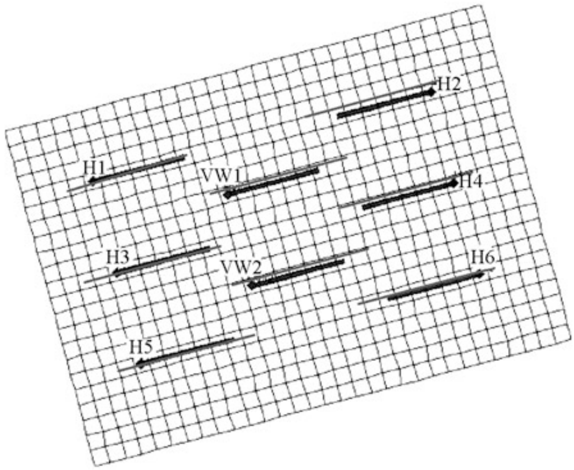


Fig. 7.46 Scheme 3

wells are determined. Through numerical simulation, the development dynamics of different design schemes are calculated, respectively. Based on the calculation, the development effects are compared. Besides, economic evaluation is made to choose the optimal design scheme with both a good development effect and economic benefits.

Seven better schemes are determined through the comparison of the basic well patterns and the development index of the supplementary well patterns. The relationship between water cut and degree of reserve recovery is shown in Fig. 7.57, the results of economic evaluation are shown in Tables 7.6 and 7.7. Through the comparison of similar schemes, we can see the following: Scheme 1 is better than

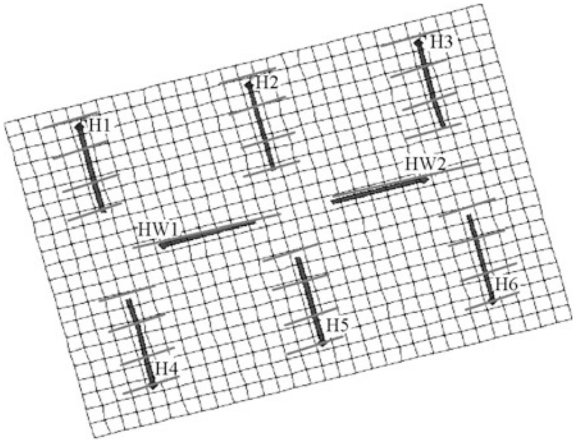


Fig. 7.47 Scheme 4

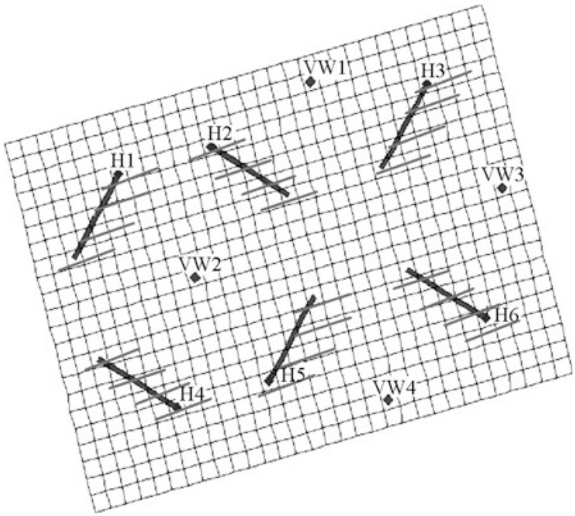


Fig. 7.48 Scheme 5

Scheme 1-1 in terms of both the development effect and economic evaluation results; Scheme 2-1 is better than Scheme 2 and Scheme 2-2 in terms of the development effect only, but due to the greater number of injection wells in Scheme 2-1, Scheme 2-2 is better in terms of economic evaluation; Scheme 3-1 and Scheme 3-2 are better than Scheme 3 in terms of the development effect, but in terms of the number of the vertical wells replaced by a horizontal well and

Fig. 7.49 Scheme 1-1

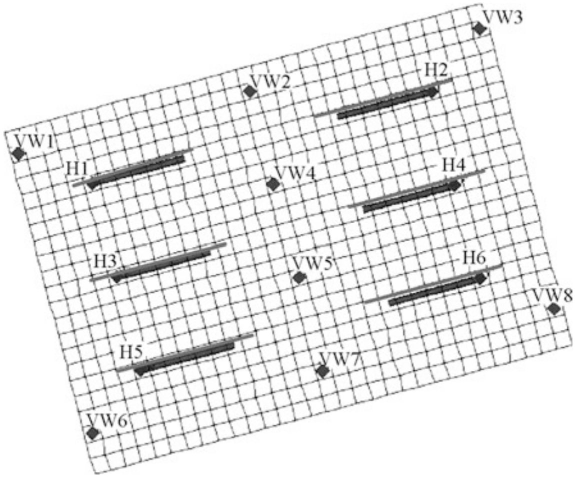
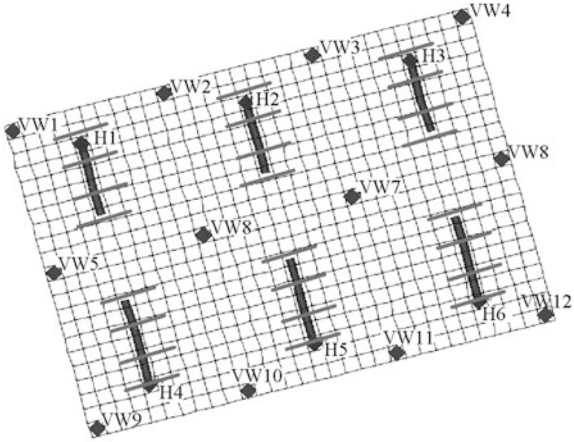


Fig. 7.50 Scheme 2-1



economic evaluation, Scheme 3-2 is better; Scheme 4-1 is better than Scheme 4 and Scheme 4-2 from the perspective of either development effect or economic evaluation; Scheme 5-1 is better than Scheme 5 from the perspective of the development effect and economic benefits.

On the basis of the research on the above basic well patterns and improved well patterns, and from the perspective of development effect and economic benefits, the

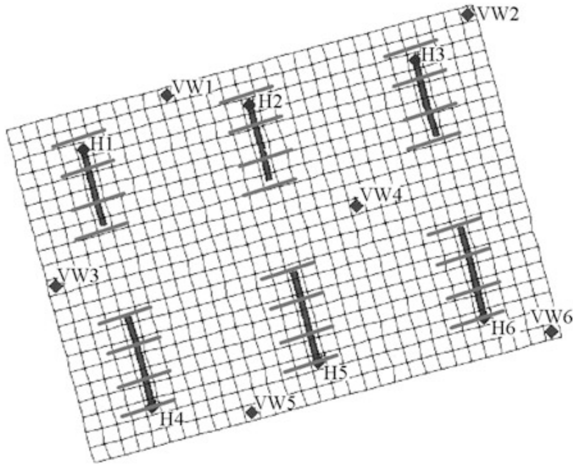


Fig. 7.51 Scheme 2-2

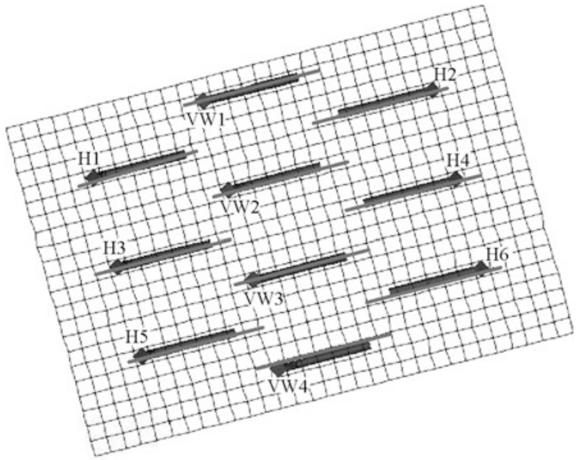


Fig. 7.52 Scheme 3-1

first batch of relatively good schemes is chosen from different types. They are Scheme 1, Scheme 2-2, Scheme 3-2, Scheme 4-1, and Scheme 5-1. The water cut and recovery-degree relationship in the selected five schemes, the inverted nine-spot diamond vertical well pattern, and unequally spaced linear injection well pattern is shown in Fig. 7.57. We can see in the figure that with the unequally spaced linear injection well pattern, Scheme 1 and Scheme 5-1, the development

Fig. 7.53 Scheme 3-2

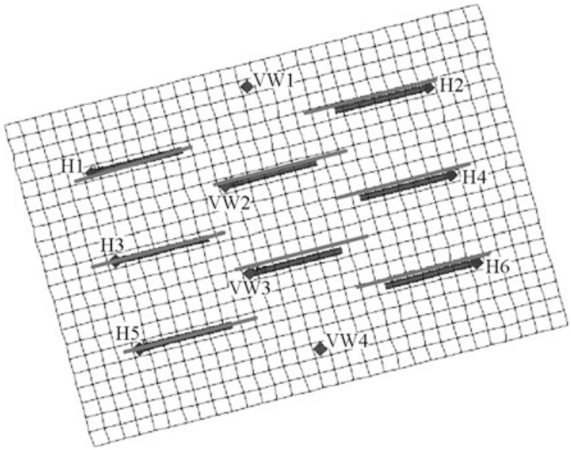
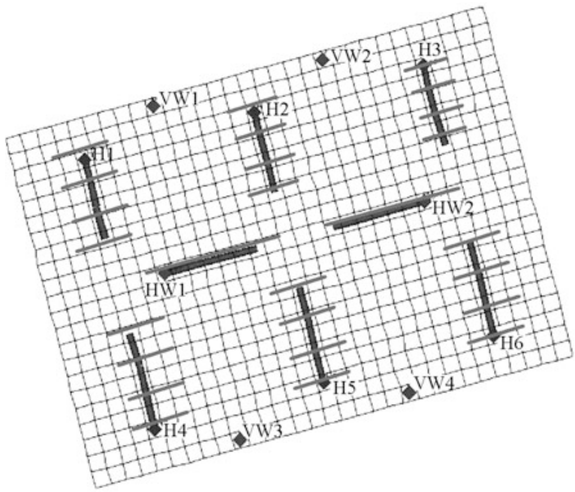


Fig. 7.54 Scheme 4-1



effect is good, but the degree of reserve recovery of the unequally spaced linear injection well pattern and the degree of reserve recovery of Scheme 1 are 2.75 percentage points and 2.39 percentage points lower than that of Scheme 5-1, respectively. Because it is difficult to form vertical fractures by means of fracturing with Scheme 1, the horizontal well productivity is low. Through comprehensive analysis and economic evaluation, Scheme 5-1 (the horizontal direction and the fracture direction forms an angle of 45º) is the best.

Fig. 7.55 Scheme 4-2

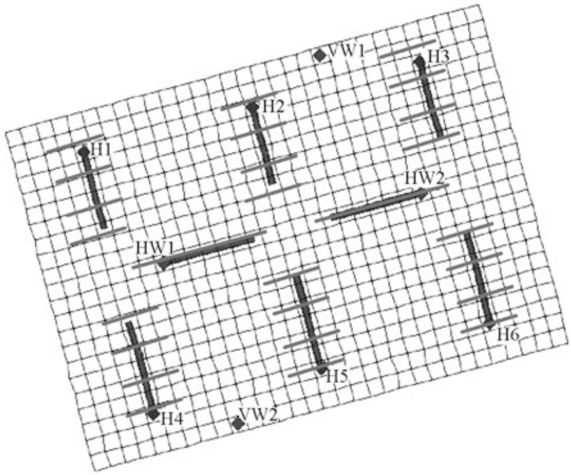
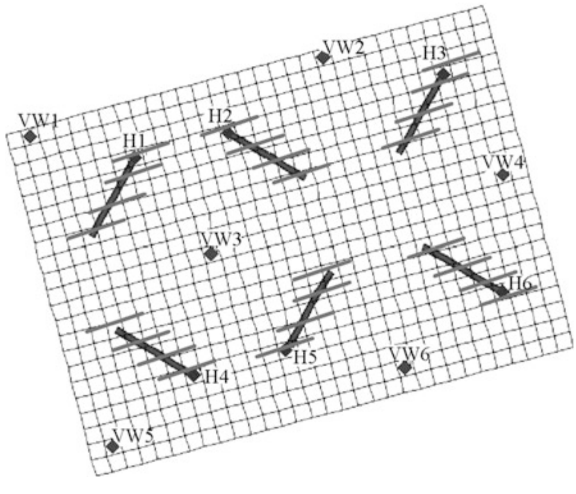


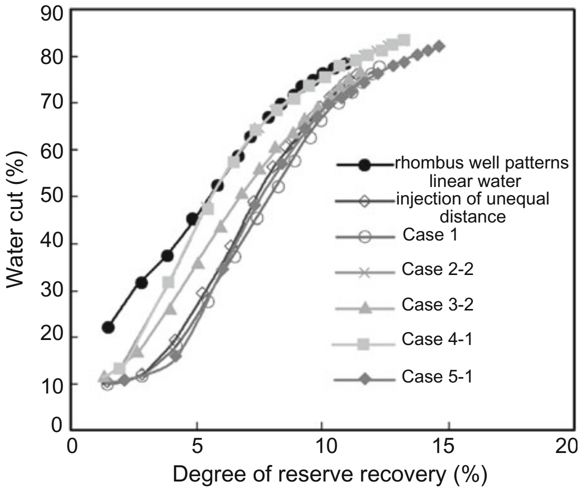
Fig. 7.56 Scheme 5-1



7.3.3 Optimal Design of Horizontal Well Fracturing

Because of the low natural production in the low-permeability oilfield development process, fracturing is often adopted to gain economic benefits in such reservoirs. For horizontal wells, staged fracturing and volume fracturing are used to increase production. Due to the fractures in fractured reservoirs, parameters like fracture

Fig. 7.57 Comparison of the optical schemes in terms of water cut and the degree of reserve recovery



distribution characteristics should be fully considered in the deployment of horizontal wells to determine such factors as the extension direction and length of horizontal wells. When fracturing is used in the horizontal well, it is necessary to determine the following factors: the number of fracturing fractures of a certain length, the angle between the fracture direction and the horizontal section, fracture half length, fracture height, fracture conductivity, etc. This plays an important role in the whole system, the effective control of reserves, and the effect of water flooding. The coexistence of artificial and natural fractures leads to reservoir heterogeneity. Natural fracture is closed under formation conditions, with low permeability; artificial fracture supports fracture permeability, which can reach several darcies. The reservoir seepage capacity is mainly controlled by artificial fracture, so the well pattern optimization of low-permeability reservoirs mainly means the reasonable match of artificial fracturing and the well pattern. In low-permeability reservoirs, permeability and ground stress usually have obvious anisotropy. Before water injection development, the reasonable matching relation between the horizontal row direction and fracture system must be well studied, which is one of the key factors to determine reservoir development effect.

When horizontal wells are used for the development of low-permeability reservoirs, there are many factors affecting production capacity after artificial fracturing transformation, including the number of artificial fractures, fracture conductivity, and the location of the fractures. Here is how simulation technology is applied to make the fracturing optimal design.

Table 7.6 Comparison of the simulation results of basic well patterns

Project	Number of vertical producers	Number of vertical injectors	Number of horizontal producers	Number of horizontal injectors	Annual oil output at the early stage (10^4 t)	Annual production rate at the early stage (%)	Cumulative production in the 15th year (10^4 t)	Comprehensive water content (%)	Degree of reserve recovery (%)	Net present value (million yuan)	Internal rate of return (%)
Former diamond well pattern	13	3			1.09	1.4	8.12	76.94	10.47	7.95	14.2
Unequally spaced linear injection well pattern	12	6			1.51	1.94	7.59	86.43	9.79	8.5	13.7
Scheme 1		3	6		1.03	1.33	9.17	75.75	11.82	29.1	41.8
Scheme 2		3	6		1.51	1.94	7.59	86.43	9.79	19.69	43.3
Scheme 3			6	2	1.5	1.93	8.44	85.74	10.88	16.71	31.2
Scheme 4			6	2	1.46	1.88	7.23	86.95	9.32	17.61	39.5
Scheme 5		2.5	6		1.53	1.97	10.47	81.73	13.5	41.07	91.6

Table 7.7 Comparison of the simulation results of improved well patterns

Project	Number of vertical producers	Number of vertical injectors	Number of horizontal producers	Number of horizontal injectors	Annual oil output at the early stage (10^4 t)	Annual production rate at the early stage (%)	Cumulative production in the 15th year (10^4 t)	Comprehensive water content (%)	Degree of reserve recovery (%)	Net present value (million yuan)	Internal rate of return (%)
Scheme 1-1		4	6		1.09	1.4	8.12	76.94	10.47	26.17	35.8
Scheme 2-1		6	6		1.03	1.33	9.17	75.75	11.82	30	43.7
Scheme 2-2		3	6		1.51	1.94	7.59	86.43	9.79	34.61	70.8
Scheme 3-1			6	3	1.5	1.93	8.44	85.74	10.88	16.44	19.3
Scheme 3-2		1	6	2	1.46	1.88	7.23	86.95	9.32	23.09	32.6
Scheme 4-1		2	6	2	1.53	1.97	10.47	81.73	13.5	29.86	48.1
Scheme 4-2		1	6	2	1.09	1.4	8.12	76.94	10.47	27.89	49.5
Scheme 5-1		3	6		1.03	1.33	9.17	75.75	11.82	43.03	89.7

The optimization analog computation below is based on the reservoir characteristics and the well pattern deployment of actual oilfields. For example, the geologic characteristics and distribution rule of oil sand bodies are taken from Gu 88 well block of D Oilfield, and the actual parameter field is used as the geological model. Based on this, different well pattern schemes are designed, with a horizontal section 600 m long, a production allocation of 10 t and 15 years of simulation production.

1. The angle between the fracture direction and the horizontal section

Under the condition that the horizontal well extension direction is the transverse channel direction, four schemes are designed with different angles between the horizontal well and fracture direction, and different fracture distributions (Table 7.8). The development effect is simulated and simulation production period is 15 years.

For Scheme 2 and Scheme 4, the angle between the fracture direction and the horizontal section is 90°; for Scheme 1 and Scheme 3, the angle between the fracture direction and the horizontal section is 45° (Fig. 7.58).

An analog computation is made with a certain length of fracture. Through it, the angle between the fracture direction and the horizontal section, and the simulation results of the development effect are found out (Fig. 7.59).

The simulation results show that there is little difference in degree of reserve recovery when the angle between the fracture direction and the horizontal well is 45° or 90°. Therefore, when the horizontal well direction intersects the river channel to form an angle of 45° between the hydro-fractured fractures and the direction of the horizontal wells, the development effect will not be affected.

2. The design of fracture numbers

Three schemes are designed with three, four, or five fractures involved in each scheme, respectively. The fractures are unevenly distributed in the horizontal sections. The specific design is shown in Table 7.9. The smallest distance between

Table 7.8 Design schemes of different modes of intersection between the horizontal well and the fracture direction

Scheme number	The angle between the fracture direction and the borehole (°)	Distribution of fracture	Number of fractures	Length of fracture (m)	Model permeability (10^{-3} μm^2)	Production mode
1	45	Even	4	100	5	Liquid control
2	90	Even	4	100	5	Liquid control
3	45	Uneven	4	100	5	Liquid control
4	90	Uneven	4	100	5	Liquid control

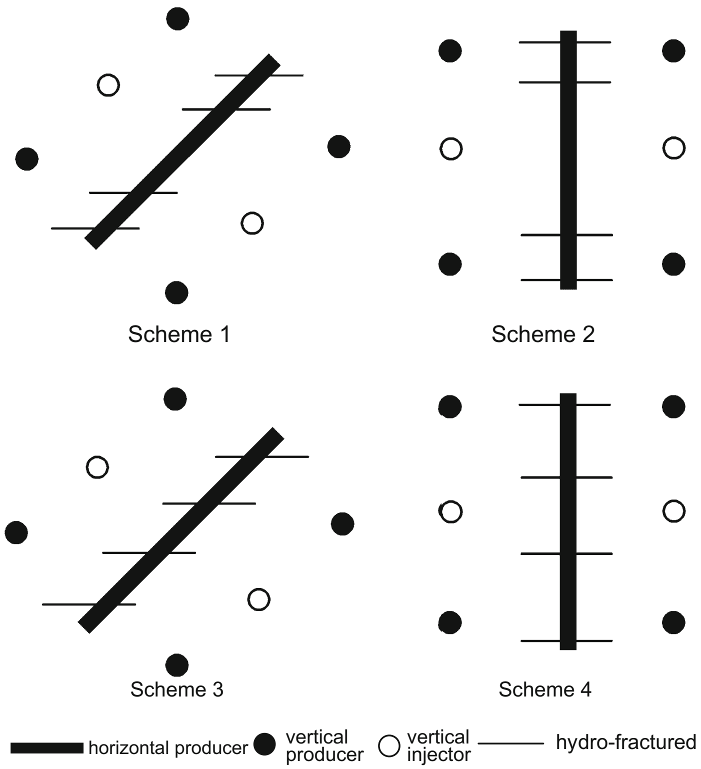


Fig. 7.58 Different design schemes reflecting the intersection relation between the horizontal well and the fracture direction

Fig. 7.59 Degree of reserve recovery and water cut relation in horizontal wells with different modes of fracture

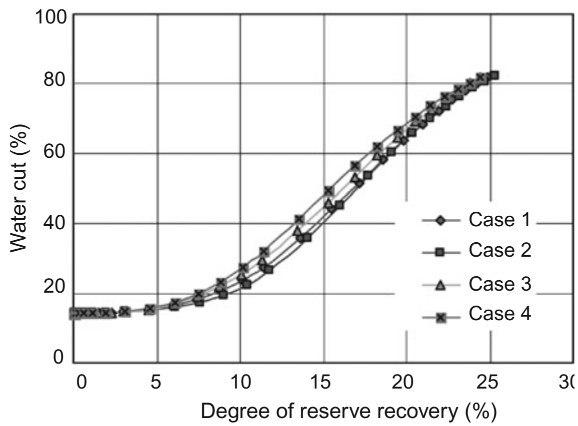


Table 7.9 Optimal design schemes of the number of hydro-fractured fractures for horizontal wells

Scheme number	The angle between the fracture direction and the borehole (°)	Distribution of fracture	Number of fractures	Length of fracture (m)	Model permeability (10^{-3} μm^2)	Production mode
1	45	Uneven	3	100	5	Liquid control
2	45	Uneven	4	100	5	Liquid control
3	45	Uneven	5	100	5	Liquid control

the fractures is 120 m. When three fractures are formed by fracturing, two of them are close to the well heel; when four fractures are formed by fracturing, two of them are close to the well heel and the well toe, respectively; when five fractures are formed by fracturing, two of them are close to the well heel and another two are close to the well toe, with the other one in the middle, as shown in Fig. 7.60. The simulation production period is 15 years (Fig. 7.61).

The simulation results show that when three, four, and five fractures are fractured, respectively, there is not much difference between them in degree of reserve recovery. When the number of fractures is greater than three, it will not help to increase the development effect significantly. When the degree of reserve recovery is 5–15 %, the degree of reserve recovery is the highest in the horizontal well with four fractures under the condition of the same water cut. It indicates that under the condition of the current well pattern and horizontal section length, four fractures are needed at most.

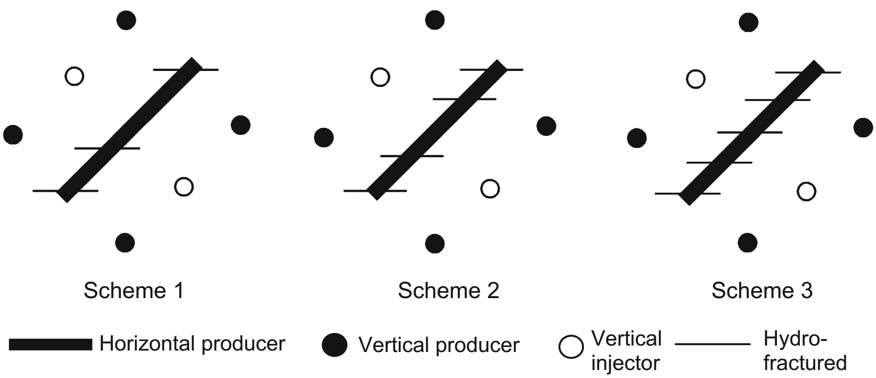


Fig. 7.60 Number of hydro-fractured fractures for horizontal wells

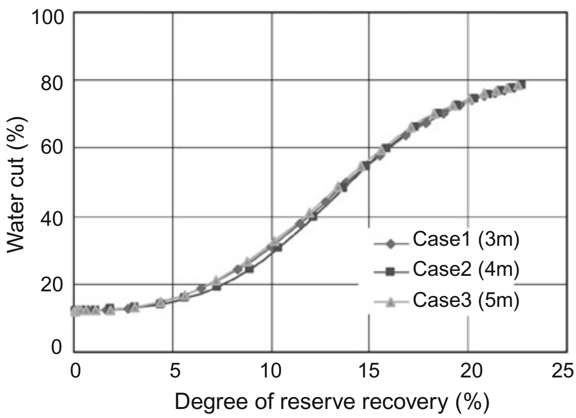


Fig. 7.61 Relation between the degree of reserve recovery and water cut of horizontal wells under the condition of different number of fractures

Normally, production increases with the increase of the number of fractures. However, the increment declines gradually after the fractures reach a certain number. Relevant studies suggest that the best fracture number is three to five. Of course, it mainly depends on the horizontal section length. The longer the horizontal section is, the more fractured fractures are needed and the higher the production will be.

With theoretical method, an analysis is made of the influence of the number of artificial fractures on horizontal well development effect. The results show that with the increase of the number of fractures, the horizontal well production gradually increases, but the increment declines gradually. There is a boundary value for each horizontal section length. When the horizontal section length is 300 m, the number of fractured fractures should not be more than three. When the horizontal section length is 300 m, it should not be more than six.

3. The optimization of Fracture length

Under certain conditions, the longer the fractures of a fractured horizontal well is the better. However, with the extension of production time, the advantages of long fractures are weakened gradually. The cumulative output differs little when the penetration rate is 100 and 30 %, respectively. In actual injection-production well pattern, if the maximum fracture length is set as the half of the well spacing and it is coupled with the well pattern pressure system, then effective displacement will be established to obtain a favorable production. Too large a scale may lead to the connection to the water well fracture system because of the pressure, resulting in water channeling. Besides, the bigger the fracturing scale is, the bigger the investment.

The hydro-fractured fractures are designed to be 50, 80, and 100 m long, respectively, with an uneven distribution in horizontal well sections. The specific designs are shown in Table 7.10. The fracture distribution is shown in Fig. 7.62. The simulation production period is 15 years (Fig. 7.63).

Table 7.10 Optimal design schemes of the lengths of fractures

Scheme number	The angle between the fracture direction and the borehole (°)	Distribution of fracture	Number of fractures	Length of fracture (m)	Model permeability (10^{-3} μm^2)	Production mode
1	45	Uneven	4	100	5	Liquid control
2	45	Uneven	4	80	5	Liquid control
3	45	Uneven	4	50	5	Liquid control

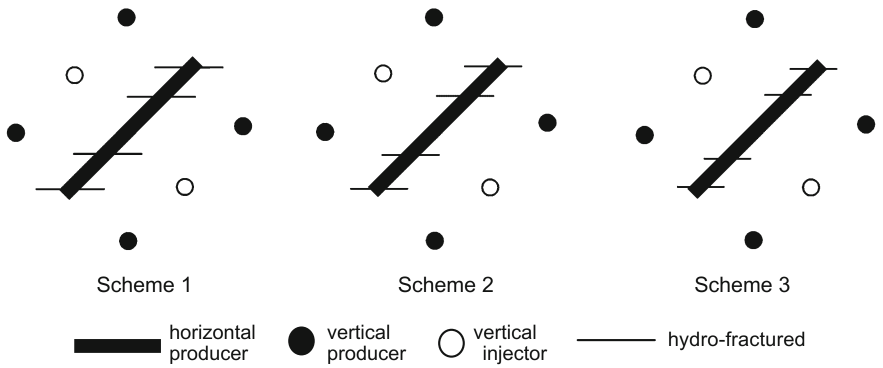


Fig. 7.62 Optimization schemes of horizontal wells with different lengths of hydro-fractured fractures

The simulation shows that if the fracture lengths are 50, 80, and 100 m, respectively, there is not much difference in degree of reserve recovery after a production period of 15 years, that of 80 m length being the best. For an area with a 250-m well spacing, the fracturing scale should not be too big and a little more than 50 m would be all right. If it is too long, there will appear early breakthrough and quick water cut rise. However, it must be ensured that the effective scale is more than 50 m. Therefore, 80 m is recommended in the actual fracturing.

4. The influence of fracture conductivity

Oil production increases with the increase of fracture conductivity, which exerts a great influence on production. After the crack length reaches a certain value, however, the effect becomes smaller and smaller. Therefore, based on different formation conditions, it is necessary to get the best fracture conductivity through the

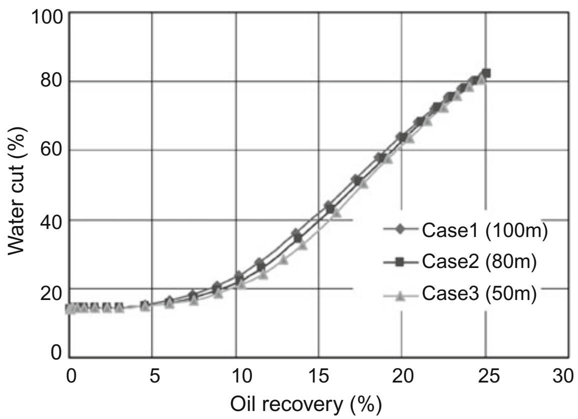


Fig. 7.63 Relation between the degree of reserve recovery and water cut of horizontal wells under the condition of different fracture lengths

optimization of proppant or operation scale. The fracture flow conductivity is the lower, then the cumulative production is the smaller, and the water cut is also the smaller. With the increase of flow conductivity, however, the cumulative production decreases with the increase of the increment. Therefore, we should choose the optimal fracture conductivity according to different circumstances.

a. When the horizontal well is parallel to the fracture direction, the water breakthrough in horizontal wells will occur late, the oilfield's production duration will be lengthened, and the ultimate recovery of the reservoir will increase slightly with the increase of the ratio of fracture permeability to matrix permeability.
b. When the horizontal well is perpendicular to the fracture direction, the water breakthrough in horizontal wells will occur soon, the oilfield's production duration will be shortened, and the ultimate recovery of the reservoir will decrease slightly with the increase of the ratio of fracture permeability to matrix permeability.

5. The influence of the angle between the injection well line and the fracture direction on the production and water cut

The influence of deflection angle on injection wells is small but regular. For a corner well, initially, the smaller the angle, then the higher the cumulative production under the condition of the same water cut and the greater the degree of reserve recovery will be. On the contrary, the degree of reserve recovery will go up with the increase of the angle under the condition of the same moisture.

7.4 Important Factors for the Well Pattern Design

The main factors influencing horizontal well patterns are as follows: permeability, ground stress, types of the horizontal well in the combinational injection-production well pattern, horizontal well length, direction of well spacing, fracture development degree, the unit area of the well pattern, well spacing, formation parameters (permeability, thickness, fluid viscosity, mobility ratio, etc.), horizontal section direction, well line direction, well pattern configuration and well pattern shape factor, and so on. Besides, in the process of actual production, the well pattern system has a great influence on injection-production dynamic parameters. Other factors, including the injection-production pressure system, drawdown pressure, and the working system of oil–water wells, also have an important influence on the development effect. The static parameters involved in the actual well pattern design include the following aspects, which will be discussed, respectively, in the following.

7.4.1 Penetration Ratio

Horizontal well penetration ratio refers to the ratio of the horizontal well length L to twice the vertical well spacing a, or the ratio of the half length of the horizontal section of the combination well pattern of the vertical well (injection) and horizontal well (production) to the vertical distance from the injector to the horizontal section. Fracture penetration ratio refers to the ratio of the fracture length to effective supply length of the reservoir. The sweep efficiency plummets with the increase of the penetration ratio of the horizontal well. This is because with the increase of the penetration ratio of the horizontal well, the mainstream line direction between the injection well and horizontal well has changed, which causes a quicker water breakthrough and decreases the sweep efficiency at the breakthrough.

7.4.2 Ground Stress

1. Influence on fracture

The fracturing fractures extend along the direction of the maximum principal stress. Therefore, the principle for well pattern deployment is that the direction in which the injection wells and production wells are connected should avoid the maximum principal stress direction. In addition, it is recommended that the rectangular five-spot system be used as the well pattern. The injection-production ratio of this form is greater than that of the inverted nine-spot well pattern. With intense injection, the water flooding moves linearly along the fractures; that is, the well line direction is consistent with the fracture direction. As a result, not only the oil and water channeling is avoided, but also the scale of artificial fracturing is expanded, which increases the production well productivity and injection capacity and improves the waterflood effect.

2. Influence on the well pattern

In the perspective of the ground stress direction, generally speaking, there are two types of well pattern deployment; i.e., the direction of the horizontal section is parallel or perpendicular to the direction of maximum principal stress.

When the direction of the horizontal section is parallel to the direction of maximum principal stress, oil is displaced to the production wells by the water flow from the injection wells, whose direction is vertical to the fracture direction, with an even and regular advancing waterline, which leads to a good development effect for high-permeability reservoirs. For low or extra-low-permeability reservoirs, however, the development effect is not good with horizontal well fracturing.

When the direction of the horizontal section is vertical to the direction of maximum principal stress, multi-section fracturing can be used to create several fractures with the horizontal well as the producer to get a high output. According to the numerical simulation results, the well pattern in which the horizontal section is perpendicular to the maximum principal stress is superior to the well pattern in which the horizontal section is parallel to the maximum principal stress in terms of oil production rate and degree of reserve recovery. However, the disadvantages of the former well pattern should also be paid attention to; that is, the water flow from the injection wells may form a coning to the horizontal production well along the nearest hydra-fractured fractures, which makes stable production difficult. This places greater demands on the repetitive shutting-off water technology of horizontal wells.

7.4.3 Influence of Types of Horizontal Wells on the Development Effect

1. The influence on water cut

At the early stage of oilfield development (half a year after an oilfield is put into production), the well pattern water cut at the time when horizontal wells are used as injection wells is significantly higher than that at the time when they are used as production wells. Whether horizontal injection wells or horizontal production wells, with the increase of penetration ratio, their water cut increases significantly. At the later stage, (10 years after the oilfield is put into production), the well pattern water cut at the time when horizontal wells are used as injection wells is lower than that at the time when they are used as production wells.

2. The influence on the average injection pressure

The average injection pressure of the well pattern at the time when horizontal wells are used as production wells is higher than that at the time when they are used as injection wells. With the increase of the permeability, the average injection pressure almost remains unchanged in the well pattern when horizontal wells are used as production wells, but when they are used as injection wells, it decreases slightly.

3. The influence on the average drawdown pressure

The average drawdown pressure of the well pattern when horizontal wells are used as injection wells is higher than that when they are used as production wells. With the increase of the permeability, the average drawdown pressure in both cases decreases slightly.

4. The influence on the degree of reserve recovery

The degree of reserve recovery of the well pattern at the time when horizontal wells are used as production wells is higher than that at the time when they are used as injection wells. The difference is not big at the early stage of production, but it is obvious at the late stage.

7.4.4 Horizontal Section Length

1. The technology boundary value analysis of the length of the horizontal section

Horizontal section length is the most important factor which influences the horizontal drainage area and the drilling quantity. DOU Hong'en et al. have derived the calculation formula of horizontal section length L according to the horizontal seepage theory:

$$\begin{aligned} &2\sqrt{2}\sqrt{R_e^2 - b^2} \le L \le 2\sqrt{2}\sqrt{a^2 - R_e^2} \\ &L_{max} = 2\sqrt{2}R_e \end{aligned} \tag{7.11}$$

where

L is the horizontal section length, m;
L_{max} is the horizontal maximum length, m;
R_e is the oil-feeding radius, m;
a is the length of the elliptic domain semimajor axis, m;
b is the length of the elliptic domain semiminor axis, m.

Therefore, the horizontal section length is influenced by the oil-feeding radius, the length of the elliptic domain semimajor axis, and the length of the elliptic domain semiminor. It is between $b < R_e < a$. It is more reasonable to set the range values of the horizontal section between $R_e \le L \le 2\sqrt{2}R_e$. Unreasonable horizontal well length not only increases the difficulty of drilling engineering, but also weakens the effect of the horizontal well production.

2. Analysis of the relation between the horizontal section length and the drainage area

There are two major methods for calculating the horizontal well drainage area. One way of calculation is to take the two ends of the horizontal section as two vertical boreholes, and the drainage area of the horizontal well as the sum of a vertical well drainage area plus the rectangular drainage area calculated with the horizontal section as the length and the diameter of the vertical well drainage area as the width. The other way of calculation is to take the drainage area as an ellipsoid, the vertical well drainage diameter plus the horizontal section length as the major axis, and the vertical well drainage as the minor axis. Based on the two methods, the horizontal drainage area formula can be obtained:

$$A = \pi R_e^2 + R_e \times L + \pi R_e \times L/4 \tag{7.12}$$

where

R_e is vertical well drainage diameter, m;
L is the horizontal section length, m

3. The influence on the areal sweep efficiency

The horizontal well length increases, but the sweep efficiency decreases. The main cause of this situation is that after the horizontal well length increases, the time gap of the water breakthrough between different points of the borehole widens. Water breakthrough occurs too soon at the points close to the injection well.

4. The breakthrough point of injection water

The intersection (the breakthrough point of the injected water) of the mainstream line and the horizontal well is generally between the two endpoints of horizontal wells, and it comes closer to the endpoints with the increase of the horizontal well length. When the horizontal well length and the network unit width are equal, i.e., when two horizontal wells are connected, the breakthrough point will be moved to the horizontal well endpoint.

5. Dimensionless length

With the increase of dimensionless length of the horizontal well, the horizontal well dimensionless production increases. However, if the horizontal well length further increases when the dimensionless length reaches a certain extent, the dimensionless output increases only modestly. Therefore, from economic considerations, the dimensionless length of the horizontal well should be controlled in a certain range, appropriately 0.5.

7.4.5 Optimal Design of the Horizontal Section Direction

In low permeable oilfields, the deployment of the water injection development well pattern is very important as a result of the existence of reservoir fracture. If the azimuth layout of horizontal wells is reasonable, the areal scanning system of waterflood will be in an optimal condition and good development effects will be achieved. Otherwise, the injected water will rapidly advance along the fracture system, causing the well's breakthrough and water flooding soon. Therefore, the azimuth of horizontal sections and its reasonable configuration with the bearing and fractures is a key to the success of the low-permeability oilfield development.

The azimuth of horizontal sections is closely related to the following factors: the reservoir structure, fault location, the sedimentary type and boundary of oil sand bodies, the stress distribution in the reservoir, and the development situation of the natural fracture. If the natural fracture system in a reservoir is not developed or there are only blind fractures in it, which does not lead to water channeling phenomenon in water injection development, then the horizontal section should extend in the direction of the main sand body belt and should be vertical to the direction of the blind fractures. For a water flooding reservoir, if natural fractures in the reservoir are relatively well developed, then, after the main extension direction of the natural fracture is determined, the horizontal well section direction should be parallel to the fracture extension direction or should form a certain angle with the fracture extension direction, in order to achieve the best effect of development.

7.4.6 Optimization Research on the Well Line Direction

Usually, the economic benefits of low-permeability reservoirs need to be achieved through fracturing of production wells. The coexistence of artificial and natural fractures causes the heterogeneity of reservoirs. Natural fractures are closed under formation conditions and their permeability is low. On the other hand, the permeability of artificial prop fracture can reach several darcies. What controls the capacity of reservoir seepage is mainly artificial fracture. Reservoir directional characteristics mainly include the directions of natural fracture, formation principal stress, and principal permeability. These characteristics decide the characteristics and rule of the fluid flow. The connective pores in the fracture are the main flow channels. The fracture direction depends on the principal ground stress direction. They are generally consistent. The main seepage direction refers to the matrix permeability direction in addition to the fracture permeability. It depends on the reservoir sedimentary characteristics. Therefore, well pattern optimization of the low-permeability reservoir is mainly the reasonable matching of the incipient fracture direction, and the artificial fracturing direction, and the principal permeability direction. In low-permeability reservoirs, permeability and ground stress often have obvious anisotropy. Before the water injection development, we must study the reasonable matching relation between the horizontal row direction and the fracture system. In this way, a reasonable injection-production system can be formed and serious problems such as linear waterflooding will not appear. This is one of the key factors for determining the reservoir development effect.

7.4.7 Formation and Fluid Parameters (Permeability, Reservoir Thickness, Fluid Viscosity, and Mobility Ratio)

1. The influence on production and sweep efficiency
   Formation permeability and formation thickness are proportional to the well production and fluid viscosity is inversely proportional to it. Waterflood sweep efficiency is related to formation permeability, formation thickness, and fluid viscosity.
2. Permeability anisotropy

   a. If permeability anisotropy increases, the single well production capacity in the well pattern decreases and the sweep volume coefficient increases.
   b. When permeability anisotropy is strong, the flow line in the well pattern unit presents the characteristics of parallel seepage.
   c. The stronger the permeability anisotropy is, the farther away the mainstream line breakthrough point is from the endpoint of the horizontal well.

Chapter 8
Determination of Reasonable Well Spacing Density

This chapter mainly focuses on the optimization of the well pattern in actual oilfields in light of the different types of producing wells according to the principles and deployment methods of the vector well pattern. Modern refine reservoir description technology can be utilized to present a basic understanding of the reservoir distribution, sedimentary characteristics, and characteristics of the reservoir's direction in specific oil reservoirs. Modern drilling techniques can also be utilized to choose the reasonable well pattern to effectively control the oil reserves and at the same time achieve the best water-flooding effects.

8.1 Overview of Well Spacing Density

8.1.1 *Classification of Well Spacing Density*

There are two concepts on well spacing density: one refers to the oil area controlled and invalidly controlled by each well in an oil-bearing area, which is the ratio of the total area to the total number of wells (km^2/well); the other refers to the number of wells per unit of oil-bearing area. The former is generally used overseas while the latter in China. In practical application, the well spacing density is generally divided into two types: economic well spacing density and technical well spacing density.

1. Economic well spacing density
   Economic reasonable well spacing density: Under a certain set of fiscal and taxation policies and certain oil prices, the oilfield with the well spacing density reaches the maximum profit. Economic limit well spacing density: Under a certain set of fiscal and taxation policies and certain oil prices, the total production of the oilfield is equal to the total investment, and when it increases, the oilfield production will have a negative benefit. Economic well spacing density

D. Liu and J. Sun, *The Control Theory and Application for Well Pattern Optimization of Heterogeneous Sandstone Reservoirs*, Springer Geology,
DOI 10.1007/978-3-662-53287-4_8

is a dynamic index, which varies with the development of oilfield and economic and technical conditions.

2. Technical well spacing density
   Technical reasonable well spacing density: It refers to the well spacing density determined under the present technology with relatively high water drive recovery and production rate, and fairly good development effects, without considering the economic factors. Technical limit well spacing density refers to the converted well spacing density that just makes the crude oil controlled by the whole injection and production wells flow in a quasi-linear way, under the present technology. In other words, under the technical limit well spacing density, the area can be effectively controlled with the deployed well pattern. The technical limit well spacing determines the technical limit well spacing density, which is controlled by the nature of the reservoir and varies with the development of oilfield technology.

   a. In the condition that the well spacing density is smaller than the technical limit well spacing density, among the injection and production wells there is a crude oil retention area unaffected by water flooding and uncontrolled by producing wells. In other words, the well pattern cannot control all the development area or establish effective injection and production displacement pressure system.
   b. In the condition that the well spacing density is larger than the technical limit well spacing density, the control range of the injection and production wells begins to overlap, which makes all the crude oil in the area effectively recovered by forming continuous seepage field in the injection and production units, leaving no “unaffected spots.”

8.1.2 Basic Principles for Well Spacing Density Selection

In designing oilfield development schemes, it is very important to determine the reasonable well spacing density according to the geological, fluid properties, and economic parameters. The development of China’s and other countries’ oilfields has confirmed that well spacing and the initial development of the best well pattern in oilfields are determined by the reservoir characteristics and development characteristics and that the injection-production well pattern has a direct influence on the oil production rate and oil recovery. The basic principles for density selection are as follows:

1. The well spacing density must be adapted to the continuity of reservoir to improve the control water-flooding degree and the recovery as much as possible.

The primary condition for optimizing well spacing density is the reservoir continuity. The worse the continuity is, the smaller the spacing of injection-production wells is. In other words, the bigger the well spacing density is, the better control water-flooding degree and water-flooding recovery will be. The better the continuity is, the weaker the sensitivity of injection-production well spacing and well spacing density to control water-flooding degree will be.

2. The well spacing density must meet the requirements of a certain oil production rate.

Taking into account the life of oil wells and oilfield facilities, an oilfield should recover most of the recoverable reserve when the facilities are in good condition. The well spacing density must meet the need of the basic oil production rate. In the development and design of low-permeability sandstone reservoir in China, 70–80 % of recoverable reserves is generally required to be recovered within 20–30 years.

3. The well spacing density must ensure sufficient well-controlled reserves.

When the abundance of OOIP (original oil in place) is low, the reasonable well spacing density must ensure sufficient well-controlled reserves, which can make reasonable adjustments and extend the oilfield development period in developing the oilfield.

4. Injection-production well spacing must meet a certain displacement pressure gradient.

For a low-permeability oilfield, the injection-production well spacing and pressure system must match and meet the following requirements.

Because of the nonlinear seepage characteristics in low-permeability sandstone reservoir, different degrees of actuating pressure in water flooding and the big seepage resistance existent in the low-permeability sandstone reservoir cause relatively big pressure loss between injection and production wells. Therefore, a certain pressure difference and displacement pressure gradient must be established between the injection and production wells to overcome the actuating pressure and acquire reasonable oil production.

5. The well spacing must match the length of fracture of artificial fracturing.

Generally, low-permeability oil reservoir must be fractured to increase the production per well. Therefore, in determining the reasonable well spacing density, the application of the overall optimization of fracturing technology should be considered. The well row azimuth should best match the fracture azimuth, so should the well spacing and the fracture length.

8.2 Determination of Conventional Vertical Well Spacing and Well Pattern Density

8.2.1 Methods in Terms of Reservoirs Characteristics

1. Determine well spacing density by calculating oil sand bodies.

The relation between the degree of water-flooding control, the perimeter and area of oil sand bodies, and the well spacing density can be established by the principle of mathematical statistics:

$$M_i = 1 - 0.470698 \cdot \frac{L_i^{0.5}}{A_i^{0.75}} \cdot d \tag{8.1}$$

where

M_i is the degree of water-flooding control;
L_i is perimeter of oil sand bodies, km;
A_i is area of oil sand bodies, km^2;
d is well spacing, km.

If the well pattern is square, then

$$S = \frac{1}{d^2} \tag{8.2}$$

If the well pattern is triangle, then

$$S = \frac{2}{\sqrt{3}d^2} \tag{8.3}$$

So the formula for calculating the well spacing density is:
In the square well pattern:

$$S = \left[\frac{0.470698 \cdot L_i^{0.5}}{(1 - M_i) \cdot A_i^{0.75}}\right] \tag{8.4}$$

In the triangle well pattern:

$$S = \left[\frac{0.505798 \cdot L_i^{0.5}}{(1 - M_i) \cdot A_i^{0.75}}\right]^2 \tag{8.5}$$

where S is well spacing density, well/km^2.

2. Determine well spacing density according to the empirical relation between the degree of water-flooding control and morphology of oil sand bodies.

By statistical analysis, the formula is:

$$M_i = C_1 - C_2 \cdot f^{C_3} \cdot \frac{L_i^{C_4}}{A_i^{C_5}} \tag{8.6}$$

where

C_1–C_5 is statistical coefficient;
f is well spacing density, ha/well;
L_i is perimeter of oil sand bodies, km;
A_i is area of oil sand bodies, km.

So

$$\mathrm{S} = \left[\frac{(C_1 - M_i)A_i^{C_5}}{C_2 L_i^{C_4}}\right]^{\frac{1}{C_3}} \tag{8.7}$$

In pattern water flooding,
$C_1 = 95$, $C_2 = 1.12$, $C_3 = 0.45$, $C_4 = 1$, and $C_5 = 1$.
In parallel water flooding,
$C_1 = 95$, $C_2 = 0.625$, $C_3 = 0.6$, $C_4 = 1$, and $C_5 = 1$.

3. Determine well spacing density with Diyashev's method

The effective supply radius of the well pattern is determined by the permeability of the reservoir, and the reasonable well spacing is determined according to the types of the deployed well pattern.

a. The relation between the effective supply radius and the permeability of the reservoir by statistics

$$R = 171.8 + 0.53K \tag{8.8}$$

where R is effective supply radius of the well, m;
K is permeability of the reservoir, $10^{-3}\mu m^2$.

b. The relation between the effective supply radius and well spacing
Well spacing of the five-spot well pattern is:

$$d_5 = \sqrt{\pi}R \tag{8.9}$$

Well spacing of the inverted seven-spot well pattern is:

$$d_7 = \sqrt{\frac{2\pi}{1.732}}R \tag{8.10}$$

Well spacing of the inverted nine-spot well pattern is:

$$d_9 = \sqrt{\pi} R \tag{8.11}$$

4. Determine well spacing density with the probability method.

According to the actual parameters of oilfield development, the empirical formula is obtained.

$$\lambda = 1 - \varepsilon^{\frac{1}{2}} \cdot \exp\left(-\frac{0.635 \cdot C_0}{\psi \cdot d^2}\right) \tag{8.12}$$

where

λ is the degree of water-flooding control, decimal;
ε is injection-to-producing-well ratio;
C_0 is the area of sands, m^2;
d is average well spacing, m;
ψ is conversion relation between the controlled area per well and the square of well spacing.

Five-spot well pattern spacing $\psi = 1$
Inverted seven-spot well pattern spacing $\psi = 0.866$
Inverted nine-spot well pattern spacing $\psi = 1$
For irregular well pattern,

$$\psi(\varepsilon) = 0.13975 \cdot \varepsilon^2 - 0.5359 \cdot \varepsilon + 1.40792 \tag{8.13}$$

$$\varepsilon = \frac{n_0}{n_w}$$

where

$\psi(\varepsilon)$ is well pattern correction factor;
n_0 is the number of production wells;
n_{w} is the number of injection wells.

The relation between the well pattern area and well spacing in well pattern unit is:

Well spacing of the five-spot well pattern:

$$S_5 = 2 \cdot d^2 \tag{8.14}$$

Well spacing of the inverted seven-spot well pattern:

$$S_7 = 2.60 \cdot d^2 \tag{8.15}$$

Well spacing of the inverted nine-spot well pattern:

$$S_9 = 4 \cdot d^2 \tag{8.16}$$

If the oilfield area is F, the number of development layers is n, the number of injection well is N_w, the number of production well is n_0, the average well spacing is:

$$d = \left[\frac{F \cdot n}{\theta(\varepsilon) \cdot N_w}\right]^{\frac{1}{2}} \tag{8.17}$$

$$\theta(\varepsilon) = 0.4\varepsilon^2 - 0.6\varepsilon + 2.2$$

where

$\theta(\varepsilon)$ is the well group correction factor

5. Determine well spacing density according to the degree of water-flooding control.

The volumetric sweep efficiency is calculated by Shelkachev's deformation method in different well spacing density of oilfield.

$$E_r = e^{-\frac{a}{S}} \tag{8.18}$$

where

E_r volumetric sweep efficiency, decimal;
S well spacing density, well/km^2;
a Well pattern index

The well pattern index is obtained by the following empirical formula:

$$a = 18.14\left(\frac{K}{\mu_o}\right)^{-0.4218} \tag{8.19}$$

where

K permeability of the reservoir, 10^{-3} μm^2;
μ_0 oil viscosity, mPa s.

In order to visualize the well spacing density, the calculation results of the well spacing density are converted into well spacing. The formula of well spacing is

Table 8.1 Water drive sweep coefficient in different well spacing densities of G979

Well spacing density, well/km^2	115	74	51	38	29	23	18	15	13	11	9
Well spacing, m	100	125	150	175	200	225	250	275	300	325	350
Volumetric sweep efficiency, %	95.5	93.0	90.1	86.7	83.0	79.0	74.8	70.4	65.8	61.2	56.6

considered in terms of the irregular triangular well pattern (because the irregular triangular well pattern is basically applied to complex fault block oil reservoir).

The calculation formula of well spacing is:

$$d = \sqrt{\left(\frac{S}{86.6}\right)} \times 100 \tag{8.20}$$

The formula for well spacing of area well pattern is:

$$d = 2\sqrt{\left(\frac{S}{\pi}\right)} \times 100 \tag{8.21}$$

Case study: the average absolute permeability of fault block reservoir G979 is 61×10^{-3} μm^2, and the crude oil viscosity of the reservoir is 3.4 mPa s, which can be used to calculate the volumetric sweep efficiency of different well spacing density (Table 8.1; Fig. 8.1).

As shown in Table 8.1 and Fig. 8.1, the volumetric sweep efficiency increases with the increase of well spacing density. To achieve better development results, the degree of water-flooding control should reach more than 70 %. For the actual situation of G979 fault block, when the degree of water-flooding reaches 80 %, the

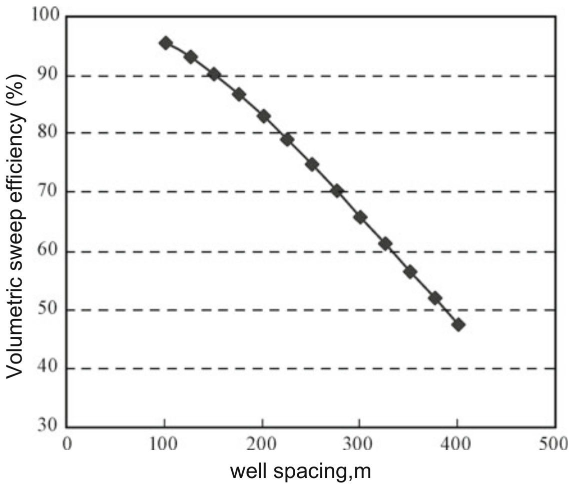


Fig. 8.1 The curve of volumetric sweep efficiency in different well spacing densities in fault block G979

corresponding well spacing density is 23 well/km^2 and the corresponding well spacing is about 225 m.

6. Determine well spacing density with the empirical formula method.

There is a certain relation between well spacing density and oil recovery, and the simplified formula put forward by USSR scientist V.N. Shelkachev is:

$$E_R = E_D \cdot E_r = E_D \cdot e^{-a.S'} = E_D \cdot e^{-a/S} \qquad (8.22)$$

where

E_R is oil recovery, decimal;
E_D is oil displacement efficiency, decimal;
S' is well spacing density, ha/well;
S is well spacing density, well/km^2;
a is well pattern index, decimal.

According to the actual data of 144 oilfields or development blocks in China, the Research Institute of Petroleum Exploration and Development (RIPED) of China takes advantage of Shelkachev's equation to sum up the relation between the final recovery and well spacing density (Table 8.2) by dividing the different mobility (k/μ) into five intervals.

A case study: according to the parameters and oil displacement efficiency of reservoir G979, the expression on the calculation of well spacing density and recovery percent for Group IV is:

$$E_R = 0.4382e^{-0.05423S} = 0.4832e^{(-5.423/S')}$$

According to the Shelkachev's formula and the expression for Group IV, the relation between well spacing density and recovery percent is shown in Table 8.3 and Fig. 8.2.

It is shown in Fig. 8.2 that the recovery increases with the increase of well spacing density, but the degree of increase is different. When the well spacing density is small, the recovery increases rapidly with the increase of the well spacing density. When the well spacing density is less than 29 well/km^2 (well spacing is

Table 8.2 The relation between well spacing density and the recovery percent of different oilfields in China

Category	Mobility (10^{-3} μm^2/mPa s)	Number of reservoirs	Regression correlation formula
I	300–600	13	$E_R = 0.6031e^{-0.02012S}$
II	100–300	27	$E_R = 0.5508e^{-0.02354S}$
III	30–100	67	$E_R = 0.5227e^{-0.02635S}$
IV	5–30	19	$E_R = 0.4832e^{-0.05423S}$
V	<5	18	$E_R = 0.4015e^{-0.10148S}$

Table 8.3 The final recovery in different well spacing densities in fault block G979

Well spacing density, well/km^2		115	74	51	38	29	23	18	15	13
Well spacing, m		100	125	150	175	200	225	250	275	300
Final recovery, %	V.N. Shelkachev	53.9	52.3	50.4	48.3	46.0	43.5	40.8	37.1	35.3
	Expression for Group IV	46.3	45.2	43.9	42.4	40.8	39.0	37.0	35.0	32.9

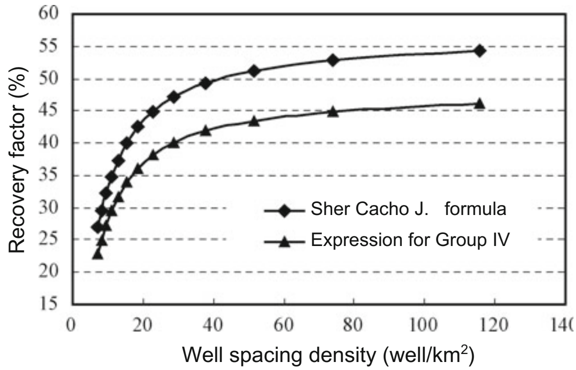


Fig. 8.2 Relation between well spacing density and the final recovery factor in reservoir G979

200 m), the oil recovery increases significantly; however, when the well spacing density is more than 29 well/km^2, the increase of recovery is not obvious, which proves that the well spacing density of 29 well/km^2 is reasonable, with the corresponding well spacing of 225 m.

8.2.1.1 Methods for Determining Well Spacing Density in Terms of Production Performance

In the process of oilfield development, there are a lot of production dynamic data. These data can be reasonably used and analyzed to understand the law of reservoir development and the law of oil and water movement and to analyze the development policy, development strategies, and the relation between well pattern and production dynamics, etc.

1. N_p-nt empirical formula

   a. Formula derivation

According to the research of well patterns in multiple fault block oilfields and small oilfields, the cumulative oil production of the oilfield and the development time and the number of wells in the development of the oilfield meet the following types of relation.

$$N_{\rm p} = A + Bnt \tag{8.23}$$

where

$N_{\rm p}$ is cumulative oil production, 10^4 t;
$n \times t$ is cumulative production characteristic value;
n is total well number;
t is development years, a;
A, B are fitting constant.

It shows that the cumulative oil production has a linear relation with the multiplied product of the number of production wells and time. The higher the correlation coefficient is, the better the fitting of the empirical formula is.

Formula (8.23) can be simply determined by the actual production data, so the number of wells in the reservoir is:

$$n = \frac{N_{\rm p} - A}{Bt} \tag{8.24}$$

The well numbers are different. When $N_{\rm p}$ and t have different values, it easily helps predict the required total number of wells in the future oilfield development.

When t becomes big enough to completely recover the whole recoverable reserves, the cumulative oil production is equal to the recoverable reserves.

$$n = \frac{N_{\rm r} - A}{Bt} \tag{8.25}$$

In practical application, it can simplify the analysis and calculation in two situations. (1) n is the total number of flowing wells; (2) n is the total number of wells (including the closed wells). The essence of this formula is the recurrence relation based on the contribution of the actual production wells to the production of the oilfield. For the development of new oilfields, related formula calculation can be applied.

b. Conditions for applying the formula

- When an oilfield has been officially put into operation for a period of time and has established a basic well pattern with a certain scale of production, the total number of wells needed to recover the total recoverable reserves in the present production condition in a certain production time is predicted.
- Suitable for the stage of stable and slow increase in water cut (Figs. 8.3 and 8.4).
- In the development process, there is no large-scale well pattern adjustment like drilling a lot of new wells. Otherwise, the production scale after stable production should be studied.
- Suitable for oil reservoir with good $N_{\rm p}$-nt linear correlation coefficient.

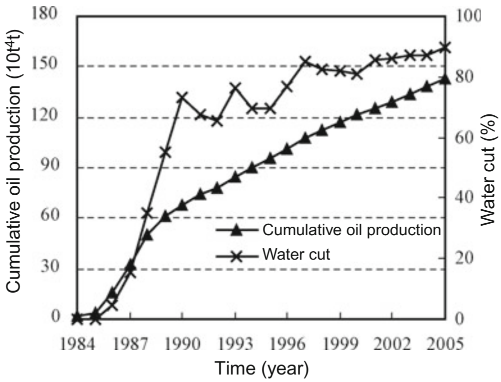


Fig. 8.3 Change of cumulative oil production and water cut with time in G979

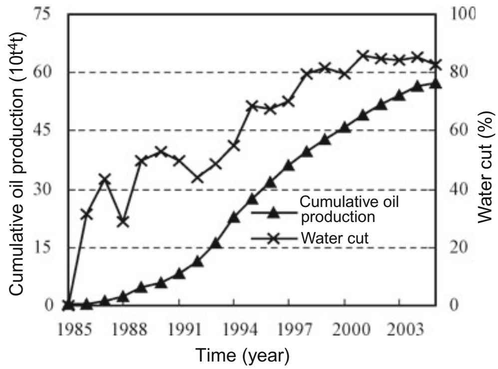


Fig. 8.4 Change of cumulative oil production and water cut with time in Z1270

– Suitable for the calculation and analysis in a reservoir developed in one layer. The reservoirs with multiple sets of layers should be calculated layer by layer.

c. Application of the formula

Case study 1: The fitting curve is obtained by using the actual production data of G979 fault block (Fig. 8.5). The fitting linear formula is: $y = 0.1443x + 52.708$, correlation coefficient $R^2 = 0.9712$, i.e. $A = 52.708$, $B = 0.1143$. Development time being $t = 30$a and recoverable reserve $N_p = 237 \times 10^4$ t, then substitute the value of A and B into the empirical formula:

$$n = \frac{N_p - A}{Bt} = \frac{237 - 52.708}{0.1443 \times 30} = 42$$

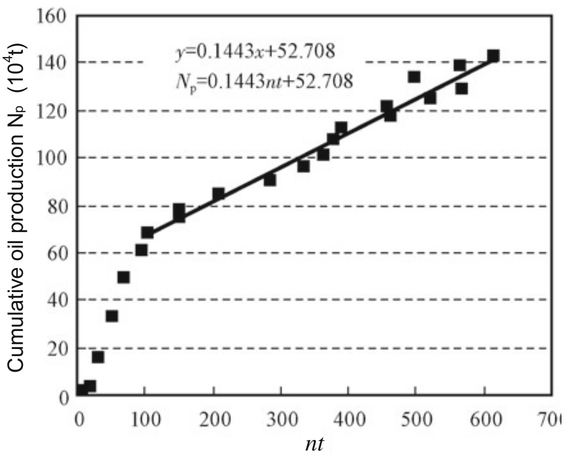


Fig. 8.5 Fitting curve of N_p-*nt* empirical method in G979

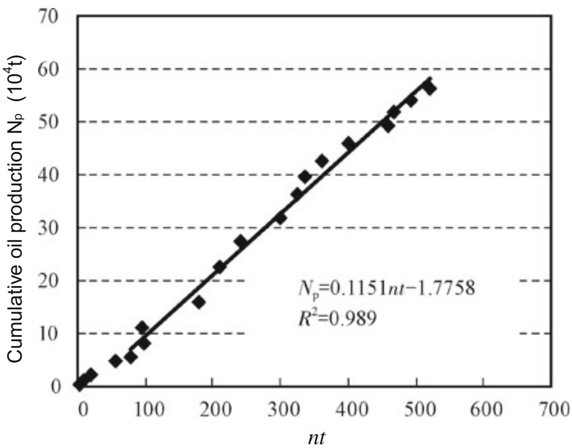


Fig. 8.6 Fitting curve of N_p-*nt* empirical method in Z1270

According to the current situation, to recover all the recoverable reserves of G979, until 2014, the needed are 42 wells including five newly drilled wells with a well spacing density of 39 well/km^2.

Case study 2: According to the actual production data, *nt* and N_p values of reservoir Zao-1270, a fitting curve can be obtained (Fig. 8.6), the fitting linear formula being $y = 0.1151x - 1.7758$ and the correlation coefficient $R^2 = 0.989$. According to the empirical formula ($N_p = A + Bnt$), the coefficient can be obtained ($A = -1.7758$, $B = 0.1151$). The development time being $t = 30$a, substitute the value of A, B in the empirical formula:

$$n = \frac{N_\mathrm{p} - A}{Bt} = \frac{N_\mathrm{r} - A}{Bt} = \frac{75 - (-1.7758)}{0.1151'30} = 23$$

According to the current situation, to recover all the recoverable reserves of Zao-1270 reservoir until the year of 2014, twenty-three wells are needed with a well spacing density of 57 well/km^2.

2. Analysis on the law of decline

   a. Formula derivation

Oilfield development is generally divided into three periods: increasing production, stable production and decline production. For the conventional development process, there is no large-scale well pattern infill adjustment. The period of increasing production and that of stable production last a short time, and many of the fault blocks or small and medium oilfields are rapidly declining in production, and the main production is recovered in the period of decline production in fault blocks such as G979 and Z1270. If the law of decline in the middle and later period of oilfield development meets the exponential decline law, the cumulative oil production (N_p) is:

$$N_\mathrm{p} = \frac{Q_0}{a}\left(1 - \mathrm{e}^{-at}\right) \tag{8.26}$$

When t becomes big enough to completely recover the whole recoverable reserves N_r, the cumulative oil production is equal to the recoverable reserves.

$$N_\mathrm{p} = \frac{Q_0}{a} = N_\mathrm{r} \tag{8.27}$$

So combined with (8.26) and (8.27) can be transformed into:

$$N_\mathrm{p} = N_\mathrm{r}\left(1 - \mathrm{e}^{-at}\right) \tag{8.28}$$

When $A = a/n$, (8.28) can be transformed into:

$$N_\mathrm{p} = N_\mathrm{r}\left(1 - \mathrm{e}^{-Ant}\right)$$

$$1 - \frac{N_\mathrm{p}}{N_\mathrm{r}} = \mathrm{e}^{-Ant} \tag{8.29}$$

Because A is changing with the number of wells, A is a variable. To be accorded with the oilfield production decline law, modified formula (8.29) is added, in which c is the correction factor:

$$1-\frac{N_{\mathrm{p}}}{N_{\mathrm{r}}}=c\mathrm{e}^{-Ant} \tag{8.30}$$

The logarithm transformation of (8.30) is:

$$\ln\left(1-\frac{N_{\mathrm{p}}}{N_{\mathrm{r}}}\right)=-Ant+\ln c \tag{8.31}$$

Make $\ln c = B$, then (8.31) can be transformed into:

$$\ln\left(1-\frac{N_{\mathrm{p}}}{N_{\mathrm{r}}}\right)=-Ant+B \tag{8.32}$$

As is shown in (8.32), $1-\frac{N_{\mathrm{p}}}{N_{\mathrm{r}}}$ and nt in the semilogarithmic coordinate is linear, so the parameters A and B can be obtained by fitting the actual production data. The formula is restored as:

$$1-\left(\frac{N_{\mathrm{p}}}{N_{\mathrm{r}}}\right)=\mathrm{e}^{B-Ant} \tag{8.33}$$

So the cumulative production can be expressed as:

$$N_{\mathrm{p}}=N_{\mathrm{r}}\left(1-\mathrm{e}^{B-Ant}\right) \tag{8.34}$$

In this way, the relations between the cumulative production, the recoverable reserves, and the number of production wells are obtained in different periods. The cumulative production in different times with different well spacing density can be analyzed. In turn, the number of production wells needed to recover a certain amount of oil production in a certain period can be calculated.

In order to calculate the reasonable well spacing density, the formula is obtained by combining the above formula with an economic analysis.

According to the net cash flow method, the net income is:

$$\mathrm{NET}=\mathrm{p}N_{\mathrm{r}}\left(1-\mathrm{e}^{B-Ant}\right)-\left[(M+G)(1+i)^{t/2}+tD\right]n \tag{8.35}$$

When the value of NET is zero, the limit number of wells is obtained and the net income of the oilfield development is zero at that time. The derivation of the number of wells on both sides of (8.35) results in:

$$\mathrm{NET}'=\mathrm{Atp}N_{\mathrm{r}}\mathrm{e}^{B-Ant}-\left[(M+G)(1+i)^{t/2}+tD\right] \tag{8.36}$$

When NET′ = 0, n obtained is the economic reasonable number of wells:

$$n = \frac{B - \ln \frac{(M+G)(1+i)^{t/2} + tD}{PN_r At}}{-At} \quad (8.37)$$

where

N_P is cumulative oil production, 10^4 t;
Q_0 is initial oil production, 10^4 t;
t is development years, a;
n is the total number of production wells, well;
N_r is recoverable geological reserves, 10^4 t;
a, A, B, c are coefficient;
P is the price of crude oil, yuan/t;
M is drilling investment per well, 10^4 yuan;
G is ground construction investment per well, 10^4 yuan;
i is loan interest rate, decimal;
D is annual operating cost per well, 10^4 yuan.

$n \times t$ is the cumulative production characteristics value, and the calculation presumes that the production time of new well each year is half a year. In the 1, 2, 3, 4, … t years of the developing oilfield, the number of oil and water wells is increased by n_1, n_2, n_3, n_4, … n_t; the annual comprehensive utilization ratio/is well working rate;

In the first year, $nt = n_1 \times 0.5$
In the second year, $nt = n_1 \times 1.5 \times \eta_1 + n_2 \times 0.5$
In the third year, $nt = n_1 \times 2.5 \times \eta_2 + n_2 \times 1.5 \times \eta_2 + n_3 \times 0.5$
In the fourth year, $nt = n_1 \times 3.5 \times \eta_3 + n_2 \times 2.5 \times \eta_3 + n_3 \times 1.5 \times \eta_3 + n_4 \times 0.5$
…
In the t year

$$nt = n_1 \times (t - 0.5) \times \eta_t + n_2 \times (t - 1.5) \times \eta_t + n_3 \times (t - 2.5) \times \eta_3 + \cdots + n_t \times 0.5$$

In actual application, the analysis and calculation can be simplified: (1) n is the total number of opening oil and water wells in a year. (2) n is the total number of oil and water wells (including the closed well).

b. Conditions for applying the formula

- When the oilfield has been officially in operation for a period of time and has established a basic well pattern with a certain scale of oil production, the total number of wells needed to recover the total recoverable reserves in the present production condition in a certain development period is predicted;
- Suitable for the stage of stable and slow increase in water cut;

Table 8.4 Annual production data of G979

Time (year)	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
Total active wells	8	10	11	13	14	16	15	19	17	21	26
Cumulative oil production (10^4 t)	1.88	3.44	15.45	32.85	49.64	60.81	68.19	74.41	78.32	84.78	90.18
Time (year)	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Total active wells	28	28	27	26	29	27	29	30	25	27	28
Cumulative oil production (10^4 t)	95.75	101.2	107.38	112.17	117.15	121.48	124.8	128.83	133.67	138.62	142.74

Table 8.5 Calculation parameters of G979

N_r	Recoverable geological reserves (10^4t)	237
t	Main development period	30
P	The price of crude oil (yuan/t)	1800 –4700
M	drilling investment per well (10^4 yuan)	690
G	ground construction investment per well (10^4 yuan)	
i	Loan interest rate, decimal	0.045
D	Annual operating cost per well (10^4 yuan)	65

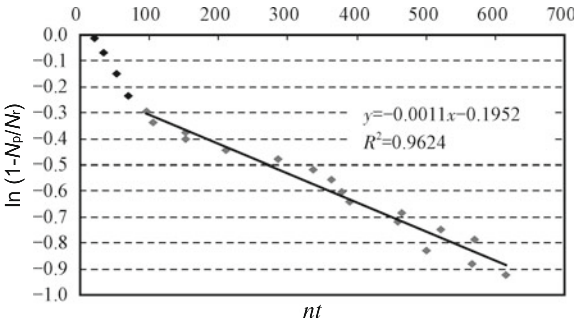


Fig. 8.7 The relation between $\ln(1 - N_p/N_r)$ and *nt* in reservoir G979

– In the development process, there is no large-scale well pattern adjustment like drilling a lot of new wells. Otherwise, the production scale after stable production should be studied;
– Suitable for the calculation and analysis in a reservoir developed in one layer series. The reservoirs with multiple layer series should be calculated layer by layer.

c. Formula application

– Case analysis 1: Fault block G979

The calculation parameters of G979 are listed in Tables 8.4 and 8.5.

The data from Tables 8.4 and 8.5 are substituted into (8.18) to get the relation curve in Fig. 8.7. The fitting linear formula is: $\ln(1 - N_P/N_r) = -0.0011nt - 0.1952$; the correlative coefficient $R^2 = 0.9624$, $A = 0.0011$, and $B = -0.1952$.

Then, substitute the parameters from Tables 8.4 and 8.5, and the value of *A* and *B* into (8.23). When the price of crude oil is fixed, *n*, the number of active opening wells, is obtained when $t = 20$, 25, 30, 35, and 40. Or when the development year *t* is fixed, *n*, the number of active opening wells, is obtained by adjusting the price of crude oil, as shown in Table 8.6 and Fig. 8.8.

Table 8.6 The reasonable number of active opening wells when the price of oil or development time changes in G979

P (yuan/t)	t (year)					
	15	20	25	30	35	40
1000	20	22	22	20	19	18
1200	31	30	28	26	24	22
1400	40	37	34	31	28	25
1600	49	44	39	35	31	28
1800	56	49	43	38	34	31
2000	62	54	47	41	37	33
2200	68	58	50	44	39	36
2400	73	62	53	47	42	38
2600	78	66	56	49	44	39
2800	82	69	59	52	46	41
3000	87	72	62	54	48	43
3200	91	75	64	56	49	44
3400	94	78	66	57	51	46
3600	98	80	68	59	52	47
3800	101	83	70	61	54	48
4000	104	85	72	62	55	49
4200	107	87	74	64	56	50
4400	110	89	75	65	57	51
4600	113	92	77	67	59	52

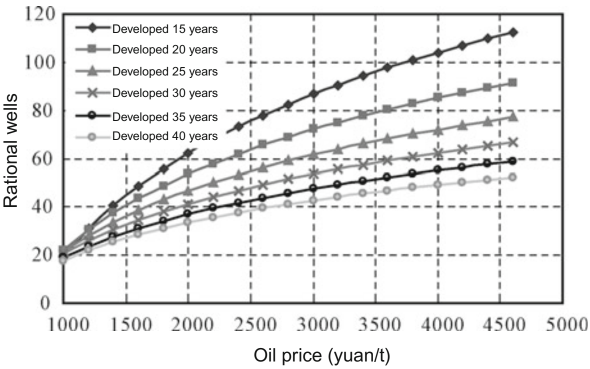


Fig. 8.8 The changing rule of reasonable number of wells in different oil prices and development years

As shown in Fig. 8.8, when the oilfield development period is over 30 years, the price of crude oil has relatively less effect on the reasonable well spacing density. However, when the development period is shorter, the price of crude oil has a relatively greater influence on the well spacing density. Under the condition of the

Table 8.7 The annual production data of Z1270 reservoir

Time (year)	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Total opening wells (well)	2	2	3	5	11	13	14	12	20	21	22
Cumulative oil production (10^4t)	0.33	0.45	1.29	2.74	5.37	6.21	8.71	11.76	16.45	23.10	28.03
Time (year)	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	
Total opening wells (well)	25	25	24	24	25	27	26	26	26	24	
Cumulative oil production (10^4t)	32.35	36.66	40.11	43.19	46.27	49.67	52.19	54.74	56.94	57.68	

Table 8.8 Parameters for the calculation of reasonable wells in Z1270

N_r	Recoverable geological reserves (10^4 t)	75
t	Main development period (a)	30
P	The price of crude oil (yuan/t)	1500–4700
M	Drilling investment per well (10^4 yuan)	460
G	ground construction investment per well (10^4 yuan)	
46i	Loan interest rate, decimal	0.045
D	Annual operating cost per well (10^4 yuan)	65

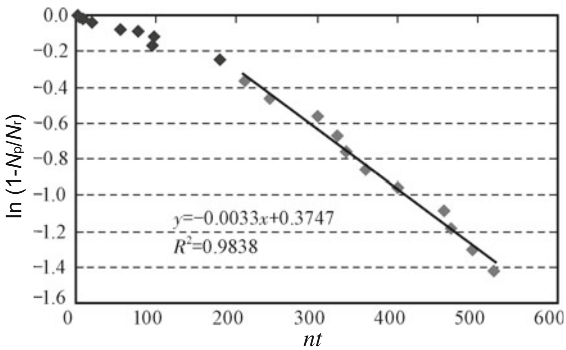


Fig. 8.9 The relation between ln$(1 - N_P/N_r)$ and nt in reservoir Z1270

same price, the shorter the development period is, the higher the well spacing density is, which is consistent with the actual situation.

Case analysis 2: Application in reservoir Z1270.

The calculation parameters of Z1270 are shown in Tables 8.7 and 8.8.

The reasonable number of well is determined when n represents the total number of opening wells, without considering the comprehensive utilization ratio.

The data from Tables 8.7 and 8.8 are substituted into (8.37) to get the relation curve in Fig. 8.9. The fitting linear formula is: $ln(1 - N_P/N_r) = -0.0033nt + 0.3747$; the correlative coefficient $R^2 = 0.9838$, $A = 0.\ 0.0033$, and $B = -0.\ 3747$.

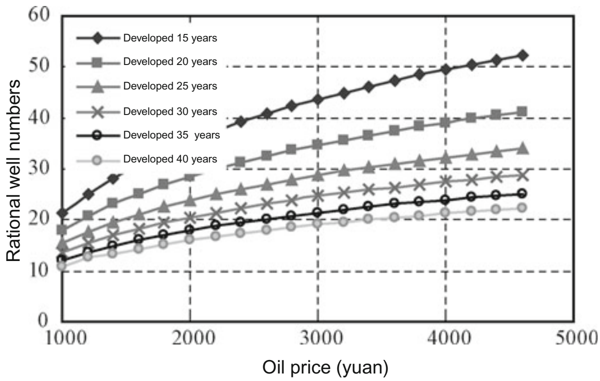


Fig. 8.10 The changing rule of reasonable number of wells in different oil prices and development years

Then, substitute the parameters from Tables 8.7 and 8.8 and the value of *A* and *B* in (8.37). When the price of crude oil is fixed, *n*, the number of flowing wells, is obtained when $t = 20$, 25, 30, 35, and 40. Or when the development year *t* is fixed, *n*, the number of flowing wells, is obtained by adjusting the price of crude oil, as shown in Fig. 8.10.

Although the crude oil properties and physical properties of Z1270 fault block reservoir are different from those of the Guan-979 fault block, the variation regularity of the reasonable well spacing density calculated by formula (8.23) is consistent.

When the oilfield development period is over 30 years, the price of crude oil has relatively less effect on the reasonable well spacing density. However, when the development period is shorter, the price of crude oil has a relatively greater influence on the well spacing density. Under the condition of the same price, the shorter the development period is, the higher the well spacing density is, which is consistent with the actual situation. At the same time, it shows that the formula is applicable in different reservoirs with different fluid characteristics and physical properties.

Case analysis 3: Ming 1 west block is located in the midwest of Wenmingzhai Oilfield, a NNE trending strip of complex fault block, with an oil-bearing area of 1.38 km^2, geologic reserves 745×10^4 t, and calibration recovery of 44.56 %.

Structural features: the small faults from north to south cut each other inside the small and complex fault block.

Reservoir features: the reservoir is composed of middle- and high-permeability layers, the shallow cementation is loose, and the upper layers have serious vertical heterogeneity.

Fluid feature: the layers are characteristic of strong hydrophilicity, high-sulfur crude oil, high oil–water viscosity ratio, big saturation pressure difference, low original solution gas–oil ratio, and calcium chloride water.

Since the development in May 1982, the Mingyi west block reservoir has been gradually building production capacity and adopting uneven well pattern in the rolling development mode. So far, the development process has experienced the rolling development stage (May 1982–December 1984), the high and stable production stage (January 1985–December 1987), the comprehensive adjustment and management stage (December 1988–July 1994), the specially stabilizing oil production by water control stage in high water cut (August 1994–December 2000), and increasing water cut with well pattern damage since January 2001.

By December 2001, Ming 1 west block had built 82 oil wells and water wells altogether with a well spacing density of 59.4 wells/km^2 . The number of oil wells: 50; that of the opening wells: 47; the opening well ratio: 94 %; daily liquid production: 1807 t; daily oil production: 186 t; comprehensive water cut: 89.7 %; cumulative oil production: 221.66 × 10^4 t; the number of water wells: 32, of which there are 23 flowing wells; the opening well ratio: 78.9 %; the daily water injection: 1497 m^3; the cumulative water injection: 888.82 × 10^4 m^3; the ratio of injection wells to production wells: 1–1.6; the recovery degree: 36.70 %; comprehensive decreasing rate: 11.64 %; natural decreasing rate: 19.2 %; and the cumulative injection-production ratio: 0.7646. The reservoir has entered the development period of high water cut, high recovery, and high well spacing density.

Table 8.9 and Figs. 8.11, 8.12, and 8.13 are obtained from the analysis of the production data of the Ming 1 west block reservoir.

This can get the fitting relationship $N_P = 0.1021nt + 121.81$, $\ln(1 - N_P/N_r) = -0.0009nt + 0.2679$. The well spacing density and the number of new wells can be calculated by the fitting formula.

As is shown in the above figure, the new method of $N_p - n_t$ and the law of decline are well applied to the fitting rate of Ming 1 west reservoir. The analyses with the same method in H3IV2$^{1-3}$ of Anpeng district and H3IV3^1 in Zhao'ao district in Zhao'ao Oilfield, Henan Province, also lead to relatively high fitting rates.

8.2.2 *Determination of Reasonable Well Spacing Density in Terms of Economic Benefits*

1. Determination of economical and reasonable well spacing density

According to the Shelkachev's relation between the recovery and well spacing density, the empirical formula of reasonable well spacing density can be established by theory of input and output, with the following factors taken into consideration: the depth of the reservoir, the drilling cost, the ground construction investment, investment loan interest rate, oil displacement efficiency, oil recovery, and crude oil price.

Table 8.9 Production data of Ming 1 west reservoir

Time (year)	Opening wells (well)	Injection wells (well)	Total opening wells (well)	Cumulative oil production (10^4 t)	Comprehensive water cut (%)	*nt*	Recovery factor of recoverable reserves	ln (1 − Np/N_r)
1982	2	0	2	1.1396	2.72	2	0.00	0.00
1983	15	1	16	8.959	21.95	32	0.03	−0.03
1984	32	9	41	24.5312	32.63	123	0.07	−0.08
1985	35	9	44	47.711	35.02	176	0.14	−0.16
1986	40	8	48	70.6337	38.85	240	0.21	−0.24
1987	37	10	47	90.7923	44.33	282	0.27	−0.32
1988	35	12	47	144.11	49.70	329	0.43	−0.57
1989	36	13	49	157.66	56.68	392	0.47	−0.64
1990	35	13	48	169.4	60.39	432	0.51	−0.71
1991	41	11	52	179.76	63.64	520	0.54	−0.78
1992	51	14	65	190.13	66.17	715	0.57	−0.85
1993	49	20	69	200.2	67.94	828	0.60	−0.92
1994	51	28	72	208.93	69.60	936	0.63	−0.99
1995	44	18	62	217	71.76	868	0.65	−1.06
1996	42	22	64	224.56	73.47	960	0.68	−1.13
1997	45	21	66	232.1	75.05	1056	0.70	−1.20
1998	44	22	66	240	75.98	1122	0.72	−1.28
1999	49	20	69	247.57	76.58	1242	0.75	−1.37
2000	58	26	70	257.21	76.94	1330	0.77	−1.49
2001	47	23	70	264.01	77.57	1400	0.80	−1.59

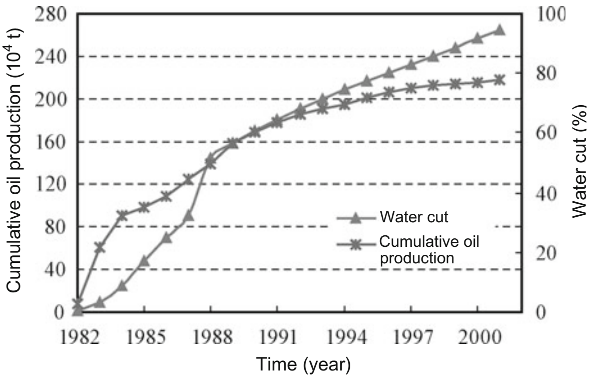


Fig. 8.11 Change of the cumulative oil production and water cut with time in Ming 1 west reservoir

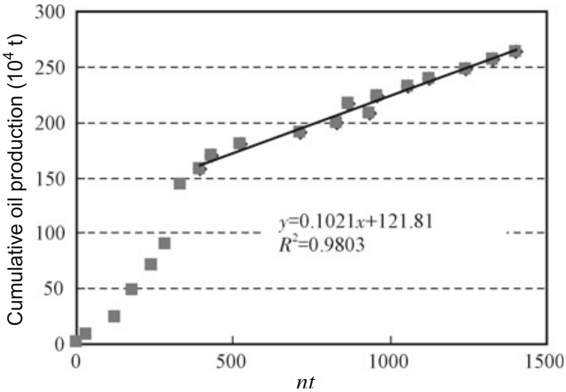


Fig. 8.12 Fitting curve of $N_p \sim N_T$ empirical method in Ming 1 west reservoir

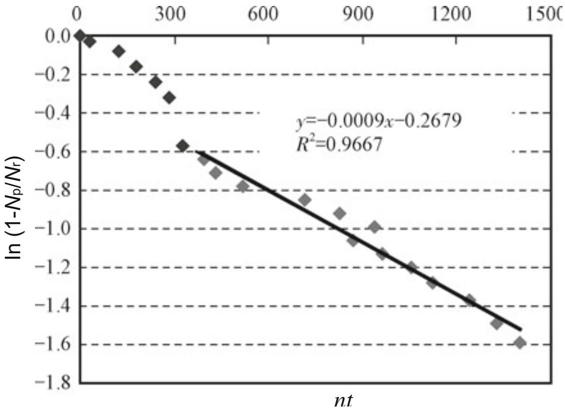


Fig. 8.13 The relation between $\ln(1 - N_P/N_r)$ and nt in Ming 1 west reservoir

In formula (8.22), the two sides of the equation are multiplied by the price of crude oil and geological reserves and then multiplied by the recovery in the main development period, which results in the total income in the main development period. The total income minus the cost of investment and drilling in the oil-bearing area leads to the relation between the net income of the oilfield development and the well spacing density:

$$\mathrm{NET_V} = NE_\mathrm{R}PE_\mathrm{D}\mathrm{e}^{-B/S} - \left[M(1+i)^{T/2} + TC\right]AS \tag{8.38}$$

where

N is geological reserves, 10^4 t
E_R is recovery of the recoverable reserves in the main development period, f;
P is crude oil price, yuan/t;
E_D is oil displacement efficiency;
B is well coefficient;
A is oil-bearing area, km^2;
M is total investment per well (drilling investment + ground investment + other investment), 10^4 yuan/well;
I is loan interest;
T is main development period, a;
C is annual operating cost per well, yuan/well a;
$NE_\mathrm{R}PE_\mathrm{D}\mathrm{e}^{-B/S}$ is crude oil sales income in the main development period;
$\left[M(1+i)^{T/2} + TC\right]AS$ is the sum of total investment and production cost during the main development period.

The extreme point of $\mathrm{NET_V}$ is the reasonable well spacing density. The derivative of S is obtained from Eq. (8.38). Assign the value of 0 to the derivative to have:

$$NE_\mathrm{R}PE_\mathrm{D}B\mathrm{e}^{-B/S} = \left[M(1+i)^{T/2} + TC\right]AS^2 \tag{8.39}$$

The well spacing density calculated from the above equation is the reasonable well spacing density. The true meaning of the formula is to obtain the largest net income in the main development period. The calculation of the well spacing density can be obtained by the iterative method and unreasonable extreme points should be removed from the calculation.

2. Determination of economic limit well spacing density

In (8.38), when $\mathrm{NET_v} = 0$, then

$$NE_\mathrm{R}PE_\mathrm{D}\mathrm{e}^{-B/S} = \left[M(1+i)^{T/2} + TC\right]AS \tag{8.40}$$

The well spacing density which meets the upper equation is the economic limit well spacing density. The meaning of the formula is the crude oil sales income of the main development period is equal to the total costs of investment and production. The calculation of the well spacing density can be obtained by the iterative method, and unreasonable extreme points should be removed from the calculation.

8.3 Determination of Technical Limit Well Spacing for the Low-Permeability Reservoir

The well spacing density in conventional oilfield development can be determined by the above methods, including reasonable well spacing density and economic limit well spacing density, etc., so as to obtain the corresponding well spacing. Due to the low permeability and low natural oil production in low-permeability oilfield, it is compulsory to analyze the technical limit well spacing regarding the seepage characteristics of layers while disregarding economic factors, in order to have economic benefits, establish effective displacement pressure system, and achieve relatively higher recovery and oil production rate.

8.3.1 Determination of the Technical Limit Well Spacing in Terms of Seepage Characteristics

The phenomenon of non-Darcy flow in low-permeability sandstone reservoir and the concept of starting pressure gradient have been widely recognized. At present, the studies on starting pressure gradient are basically concentrated in theoretical research. Owing to the difficulty in obtaining relevant parameters, the application research still focuses on qualitative concepts and can hardly be directly applied to reservoir engineering design. Laboratory studies in single-phase flow mechanism in low-permeability reservoir show that under a certain mobility, with the gradual increase of displacement pressure gradient, the fluid in low-permeability reservoir will have three seepage states: immobile, nonlinear seepage, and quasi-linear seepage. In actual reservoirs under a certain lift technology (with production pressure difference), an oil well with a certain amount of production correspondingly has three different seepage areas, the immobile area, the nonlinear seepage area (hard to seep), and quasi-linear seepage area (easy to seep), as shown in Fig. 8.14. The quantitative description of these three areas is of important practical

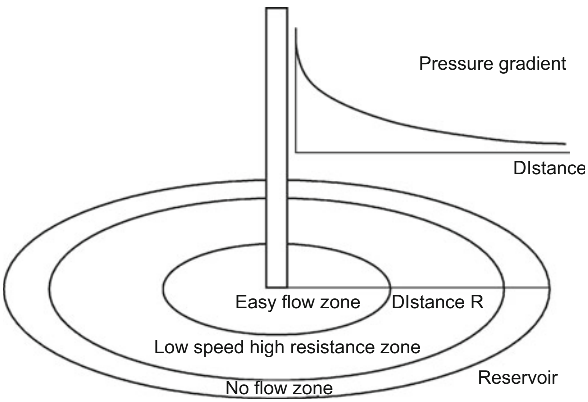


Fig. 8.14 Flow state distribution of areal radial flow in low-permeability reservoir

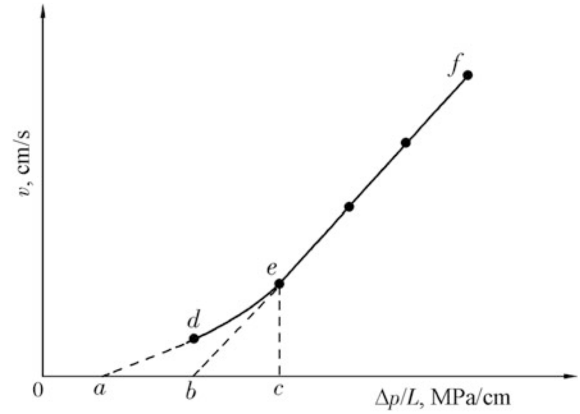


Fig. 8.15 Typical non-Darcy seepage curve

significance for revealing the seepage law of low-permeability reservoir, explaining its primary contradiction and dynamic characteristics and making corresponding reservoir reconstruction measures.

Figure 8.15 shows a typical non-Darcy seepage curve, which has three different seepage conditions: immobile (segment oa), the nonlinear seepage (segment ae), and the quasi-linear seepage (segment ef) along with the increase of displacement pressure gradient. Through tests, the value of $(\Delta P/L)_a$ can be directly determined. If the displacement pressure gradient is between 0 to $(\Delta P/L)_a$, the fluid seepage velocity is 0. When it is greater than $(\Delta P/L)_a$, the fluid begins to flow, showing a nonlinear seepage state (segment oa). The displacement pressure gradient at the point is defined as the minimum displacement pressure gradient. When the displacement pressure gradient is greater than $(\Delta P/L)_a$, it shows a linear flowing state (segment ef). The displacement pressure gradient at the c point is defined as the maximum displacement pressure gradient. The e point is the turning point of the nonlinear seepage to the linear seepage state, and the corresponding starting pressure gradient is defined as the critical starting pressure gradient.

Mathematical equations are used to, respectively, describe the curves shown in Fig. 8.15, in which segment oa and segment ef are described in lines while segment ae in starting pressure gradient is as follows:

$$\begin{cases} v = 0 & \frac{\Delta P}{L} \le \left(\frac{\Delta P}{L}\right)_a \\ v = \frac{k}{\mu}\left(\frac{\Delta P}{L} - \gamma\right) & \left(\frac{\Delta P}{L}\right)_a \le \frac{\Delta P}{L} \le \left(\frac{\Delta P}{L}\right)_c \\ v = \frac{k}{\mu}\left[\frac{\Delta P}{L} - \left(\frac{\Delta P}{L}\right)_c\right] & \frac{\Delta P}{L} \ge \left(\frac{\Delta P}{L}\right)_c \end{cases} \tag{8.41}$$

where

v is seepage velocity, cm/s;
k is effective permeability, $10^{-3}\mu m^2$;

M is viscosity mPa s;
$\left(\frac{\Delta P}{L}\right)b$ is b point pressure gradient, MPa/cm.

Fifty-eight natural rock cores in different blocks of low-permeability oilfield are selected as research objects and classified into four levels according to the air permeability (0.1–$1 \times 10^{-3}\ \mu m^2$, 1–$5 \times 10^{-3}\ \mu m^2$, 5–$10 \times 10^{-3}\ \mu m^2$, 10–$50 \times 10^{-3}\ \mu m^2$). And these samples are divided into three groups to measure the seepage curve of each core according to three experiment fluid viscosity (1.15, 6.15 and 15.71 mPa s). The fitting regression is carried out to obtain the starting pressure gradient γ of any point on segment ade:

$$\gamma = \frac{0.000013\left(\frac{k}{\mu}\right)^{0.964} + 0.012\left(\frac{k}{\mu}\right)^{2.0089}\left(\frac{\Delta P}{L}\right)^2}{0.024\left(\frac{k}{\mu}\right)^{2.0089}\frac{\Delta P}{L} + 0.0137\left(\frac{k}{\mu}\right)^{1.3999}} \tag{8.42}$$

With a great quantity of laboratory testing statistics, the displacement pressure gradients of the endpoints a and c of the nonlinear flowing segment are:

$$\left(\frac{\Delta P}{L}\right)_a = 0.1458 \quad \left(\frac{k}{\mu}\right)^{-0.4406} \tag{8.43}$$

$$\left(\frac{\Delta P}{L}\right)_c = 0.4144 \quad \left(\frac{k}{\mu}\right)^{-0.6023} \tag{8.44}$$

In actual low-permeability reservoirs, the three kinds of flowing patterns can be deduced by the steady-state theory.

Assume that an oil well of a circular homogeneous reservoir with steady-state flow and constant and steady-state production has a starting pressure gradient, the calculation formula of the production per well is:

$$q = \frac{2\pi Kh(P_e - P_w)}{\mu \ln\frac{r_e}{r_w}}\left[1 - \frac{\gamma(r_e - r_w)}{P_e - P_w}\right] \tag{8.45}$$

If an oil well has a constant production and the layer is under rigid seepage condition, then the reservoir is in a state of low-velocity non-Darcy seepage state and the seepage velocity is:

$$v = \frac{q}{2\pi rh} = \frac{k}{\mu}\left(\frac{dP}{dr} - \gamma\right) \tag{8.46}$$

Combine (8.45) and (8.46) to obtain the equation of displacement pressure gradient:

$$\frac{dP}{dr} = \frac{1}{r}\frac{(P_e - P_w)\left[1 - \frac{\gamma(r_e - r_w)}{(P_e - P_w)}\right]}{\ln\frac{r_e}{r_w}} + \gamma \tag{8.47}$$

where

q is production per well, cm^3/s;
h is effective thickness of oil reservoir, m;
P_e is reservoir pressure, MPa;
P_w is flowing pressure of oil wells, MPa;
γ is starting pressure gradient, MPa/m;
r_e, r_w is reservoir supply radius and wellbore radius, m;
r is limit control radius of oil wells, m.

As is shown in the above equation, when the reservoir is in rigid seepage condition, the displacement pressure gradient dp/dr is equal to the minimum displacement pressure gradient γ_a, the oil well production is zero, the fluid particles are no longer flowing, and the corresponding radius r is the limit control radius of r_{min} as follows:

$$1 - \frac{\gamma_a(r_e - r_w)}{P_e - P_w} = 0 \tag{8.48}$$

$$r_{min} = \frac{P_e - P_w}{\gamma_a} \tag{8.49}$$

Substitute the minimum starting pressure gradient in (8.49) obtained from laboratory experiments into (8.43):

$$r_{limit} = 6.8587(p_e - p_w)\left(\frac{K}{\mu}\right)^{-0.4406} \tag{8.50}$$

When the displacement pressure gradient is $dP/dr = (\Delta P/L)_c$ (the corresponding starting pressure gradient is $\gamma = \left(\frac{\Delta p}{L}\right)_b$, the outer boundary radius of the quasi-linear seepage zone can be obtained from (8.47):

$$\left(\frac{dP}{L}\right)_c = \frac{1}{r_{flow}}\frac{(P_e - P_w)\left[1 - \left(\frac{\Delta P}{L}\right)_b\frac{r_e - r_w}{P_e - P_w}\right]}{\ln\frac{r_{flow}}{r_w}} + \left(\frac{\Delta P}{L}\right)_b \tag{8.51}$$

$$r_{flow} = \frac{P_e - P_w}{\left[\left(\frac{\Delta P}{\mathrm{L}}\right)_c - \left(\frac{\Delta P}{\mathrm{L}}\right)_b\right]\ln\frac{r_{min}}{r_w}} \tag{8.52}$$

When $(\Delta P/L)_b$ cannot be easily determined but substituted by $\left(\frac{\Delta p}{L}\right)_b = \left(\frac{\Delta p}{L}\right)_c/2$, then:

$$r_{\text{flow}} = \frac{P_{\text{e}} - P_{\text{W}}}{\left[\left(\frac{\Delta P}{L}\right)_c - \left(\frac{\Delta P}{L}\right)_b\right] \ln \frac{r_{\min}}{r_W}} = \frac{2(P_{\text{e}} - P_{\text{W}})}{\left[\left(\frac{\Delta P}{L}\right)_c\right] \ln \frac{r_{\min}}{r_{\text{W}}}} \tag{8.53}$$

$$r_{\text{flow}} = 2.413 \cdot (p_{\text{e}} - p_{\text{w}}) \left(\frac{k}{\mu}\right)^{0.6023} \tag{8.54}$$

where

*r*flow is the flowable radius, m.

With the above method, under different injection-production pressures difference, the limit well spacing in reservoirs with different permeability values can be calculated, as shown in Figs. 8.16 and 8.17.

As shown in Figs. 8.16 and 8.17, when the injection-production pressure difference is 20 MPa, the average permeability of northern Gulong area of Gu 571 and Putaohua reservoir of Gu 463 are 23.75×10^{-3} and 4.6×10^{-3} μm^2, and the technical limit well spacing is 310 and 190 m, respectively.

8.3.2 Determination of Starting Pressure Gradient

Low-permeability reservoirs have poor physical properties, and the fluid flow has differences in the starting pressure gradient, so the differences in the starting pressure of reservoirs of different permeability values are relatively large. As starting pressure determines the pressure condition of the fluid to flow, the flow resistance and the starting pressure must be overcome in order to make the fluid flow from the matrix porous media. To recover the reservoir by driving the crude oil into the bottom of the well, it requires, from the supply boundary to the bottom of the production well, a reasonable pressure gradient larger than the starting pressure of the fluid, which is called the starting pressure gradient. In order to recover the low-permeability reservoir, it is necessary to reduce the well spacing, but that

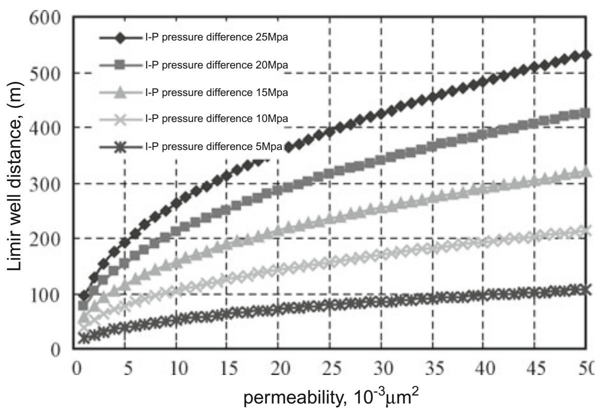


Fig. 8.16 The relation between limit well spacing and permeability under different injection-production pressure difference in Gu 463

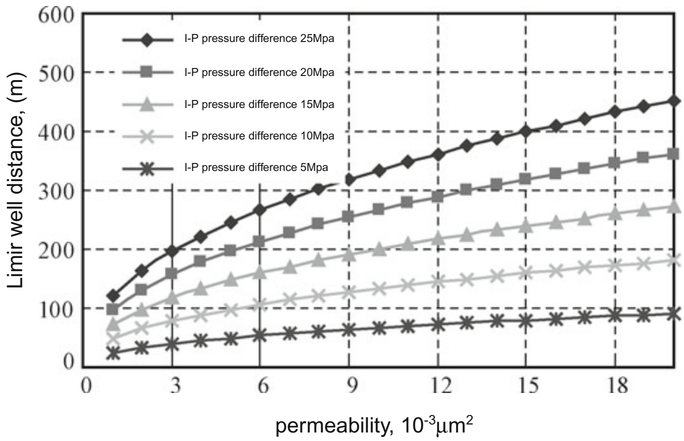


Fig. 8.17 The relation between limit well spacing and permeability under different injection-production pressure difference in Gu 571

involves increasing the development cost. Therefore, the injection-production well spacing is limited by the physical properties of the reservoir, the seepage condition, distribution of the vertical and the horizontal layers, the production technology, and the requirements of the economic conditions. For a water-flooding oilfield, reasonable injection-production well spacing is based on the reservoir's starting pressure. As the pressure gradients required by different starting pressures are different, in a water-flooding oilfield, the larger the starting pressure and the pressure gradient are, the smaller the corresponding well spacing is. The determination methods of starting pressure gradient are discussed in this Sect.

1. Determination of the starting pressure gradient in the laboratory

The basic and frequently used method to determine the starting pressure is done by laboratory experiments on actual rock cores, which is used in most oilfields.

Experiment method: indoor single-phase seepage experiments on several rock cores are conducted according to the nonlinear seepage formula of the starting pressure gradient by changing the displacement pressure difference in both ends of the core to get the volume flow under different displacement pressures. Experimental data are processed to get the "pressure-flow" curve, the intercept on the axes of which is used to obtain the starting pressure gradient of the rock cores.

Data processing: the formula of nonlinear seepage regarding the starting pressure gradient is:

$$Q = \frac{KA}{\mu}(\text{gradp} - \lambda)^n \tag{8.55}$$

where

Q is seepage quantity, mL/s;
A is cross-sectional area of seepage, cm^2;

n is seepage index, constant;
K is core permeability, 10^{-3} μm^2;
λ is starting pressure gradient, MPa/m;
p is pressure, MPa.

Take the logarithm of both sides of Eq. (8.40) and reorganize it into:

$$n\lg(\text{gradp} - \lambda) = \lg Q - \lg\frac{KA}{\mu} \quad (8.56)$$

As is shown in formula (8.56), when $Q = 0$, the displacement pressure gradient is the starting pressure gradient of the rock core. In formula (8.56), lg(gradp − λ) and lg$Q$ form a linear relation when n is fixed. However, Q in formula (8.55) is never equal to 0; therefore, Q should be of a minimum value (such as $Q = 1\times10^{-5}$ cm^3/s), in order to meet the requirement of the experimental accuracy. According to formula (8.56), when $n = 1.5$, the starting pressure gradient of every rock core is obtained by processing the experimental data. At the same time, the linear regression relation between the starting pressure gradient and the permeability is established:

$$\lambda = m \cdot K^{-n} \quad (8.57)$$

where m is the reservoir constant.

The values of m and n are obtained by regression of the experimental data in the laboratory, which are different in different low-permeability oilfields.

According to actual needs, the starting pressure gradient has different forms, such as:

$$\lambda = m \cdot (k/\mu)^{-n} \quad (8.58)$$

$$\lambda = m \cdot (\mu/k)^{-n} \quad (8.59)$$

$$\lambda = m \cdot (1/k)^{-n} \quad (8.60)$$

According to the experimental statistics, the value of n is close to or equal to 1. In general, the starting pressure gradient is influenced by the fluid properties and the characteristics of the reservoir rocks, so formula (8.58) is more practical for data statistics.

The physical meaning and justification of formula (8.58): According to rheological principles, in a single-capillary flow, when the external force is more than the resistance caused by limit shear stress, the fluid starts to flow, so the starting pressure gradient is expressed as follows:

$$Q = \frac{\pi r^4}{8\mu}\left|\frac{\Delta P}{L} - \frac{4P_0}{3L}\right| \quad (8.61)$$

$$\lambda = \frac{4P_0}{3L} = \frac{8\tau_0}{3r} \tag{8.62}$$

Studies on reservoir physical properties show the relation between capillary radius and permeability as follows:

$$r = \sqrt{\frac{8K}{\phi}} \tag{8.63}$$

So the starting pressure gradient can be expressed as:

$$\lambda = \frac{\sqrt{8\phi}\tau_0}{3\sqrt{K}} \tag{8.64}$$

where

Q is fluid quantity, mL/s;
$\frac{\Delta p}{L}$ is driving pressure gradient, MPa/m;
$\frac{p_0}{L}$ is pressure gradient, MPa/m;
R is capillary radius, μm;
K is permeability, $10^{-3}\mu m^2$;
μ is fluid viscosity, mPa s;
τ_0 is limit of fluid dynamic shear stress, MPa;
λ is starting pressure gradient, MPa/m.

Formula (8.62) and (8.64) show that the starting pressure gradient is proportional to the fluid's limit dynamic shear stress and inversely proportional to the capillary radius and the square root of rock permeability. The ratio of the fluid's limit dynamic τ_0 to the capillary radius is a constant. It shows that the starting pressure gradient of rocks is a dynamic parameter between rocks and fluid. Mobility is the concrete reflection of rock and fluid characteristics, and thus, formula (8.58) obtained from actual statistics is more reasonable.

2. Determination of the starting pressure gradient based on the field data

When the starting pressure gradient is taken into consideration, the motion equation of low-permeability reservoir is expressed as:

$$V = -\frac{K}{\mu}\left|1 - \frac{\lambda}{\text{gradp}}\right|\text{gradp} \tag{8.65}$$

where

V is seepage velocity, m/s;
K is reservoir permeability, 10^{-3} μm^2;
μ is fluid viscosity, mPa s;

gradp is pressure gradient, MPa/m;
λ is starting pressure gradient of the reservoir, constant.

For the plane radial flow, its production is:

$$q = \frac{2\pi kh}{\mu \ln \frac{R}{R_{\mathrm{w}}}} [P_{\mathrm{h}} - P_{\mathrm{f}} - \lambda(R - R_{\mathrm{W}})] \tag{8.66}$$

where

h is the effective thickness of the reservoir, m;
P_{h}, P_{f} are driving pressure, flowing pressure, MPa;
R, R_{W} are the driving radius and oil well radius, m.

Application of well pattern data in well site: for a certain well pattern, if the injection-production wells can be effectively driven, then, approximately, the well spacing L is equal to the distance of the supply boundary of the plane radial flow $R - R_{\mathrm{w}}$.

Assume $J = \frac{2\pi kh}{\mu \ln \frac{R}{R_W}}$ then

$$q = J(P_{\mathrm{h}} - P_{\mathrm{f}} - \lambda L) \tag{8.67}$$

$$q = J\Delta P - JL\lambda \tag{8.68}$$

When $X = \Delta P$ marks the horizontal coordinates and $Y = q$ marks the vertical coordinates, then

$$q = a\Delta P - b \tag{8.69}$$

The value of a and b are obtained by linear regression, and the starting pressure gradient can be calculated:

$$\lambda = \frac{b}{a \cdot L} \tag{8.70}$$

8.3.3 Determination of the Limit Well Spacing with the Starting Pressure Gradient

The reasonable well spacing for effective displacement is the key to water-flooding development effect. To determine the reasonable well spacing, the technical limit well spacing must first be determined. Only when the technical limit well spacing is determined, the reasonable well spacing with economic effect can be established. The following is to calculate the technical limit well spacing on the basis of the starting pressure.

Based on the seepage theory, in the hydrodynamic field of stable diverging-converging seepage of equal production, the seepage velocity of the mainstream is the maximum of all the streamlines; in the same streamline, the seepage velocity of the point at the same distance to the diverging-converging is the minimum. The lines linking the injection-production wells in actual reservoir are the mainstream lines, in the midpoint of which the flow velocity is the smallest and the pressure gradient at the midpoint of the main line is derived from the production formula (8.66):

$$\frac{\mathrm{d}p}{\mathrm{d}r} = \frac{p_{\mathrm{H}} - p_{\mathrm{W}}}{\ln \frac{R}{r_{\mathrm{W}}}} \cdot \frac{2}{R} \tag{8.71}$$

where

p_{H} is bottom hole flowing pressure of injection wells, MPa;
p_{w} is bottom hole flowing pressure of oil production wells, MPa;
R is supply radius, m;
r_{W} is wellbore radius, generally 0.1 m.

1. Calculating the limit injection-production well spacing according to field data

To make the oil flow in the midpoint of the injection-production well, the driving pressure gradient must be more than the starting pressure gradient at the point. Make formula (8.70) and (8.71) equal, the limit injection-production well spacing in the conditions of the given injection-production pressure difference and the reservoir permeability is:

$$\frac{P_{\mathrm{H}} - P_{\mathrm{W}}}{\ln \frac{R}{r_{\mathrm{W}}}} \cdot \frac{2}{R} = \frac{b}{a \cdot L} \tag{8.72}$$

The calculation of formula (8.72) can be done with a computer iteration.

2. Calculating the limit injection-production well spacing according to laboratory statistics rules.

Make formula (8.58) and (8.71) equal, the limit injection-production well spacing in the conditions of the given injection-production pressure difference and the reservoir permeability is:

$$\frac{p_{\mathrm{H}} - p_{\mathrm{W}}}{\ln \frac{R}{r_{\mathrm{W}}}} \cdot \frac{2}{R} = m \cdot \left(\frac{K}{\mu}\right)^{-n} \tag{8.73}$$

In the formula, $p_{\mathrm{H}} - p_{\mathrm{W}}$ is the injection-production pressure difference. On the right side of the equation is an expression of regression after laboratory test. Formula (8.73) can be used to analyze the relation between permeability and limit well spacing under various injection-production pressure differences, and the relation between the injection-production pressure differences and limit well spacing under different permeability conditions.

This can, respectively, determine the technical limit well spacing under different injection-production pressure differences and different permeability values. The two parameters can be changed to obtain the figure of technical limit well spacing, as shown in Figs. 8.16 and 8.17.

8.4 Determination of Heavy Oil Reservoir Well Pattern Density

With an analysis of the adaptability of the present well pattern and the development characteristics in heavy oil reservoir, this section introduces six calculation methods of well spacing density, including the heating radius method, the volumetric method, the method of controllable reserves per well, Shelkachev's iterative method, the injection-production ratio method, and the oil recovery rate control method.

8.4.1 The Heating Radius Method

According to the Marx–Langenheim method, the reasonable well spacing is determined by calculating the heating range of the steam or hot water injected into the reservoir regarding the principle of energy balance and the excess heat of multi-cyclic stimulation process and reservoir heterogeneity. Assume that the heating area in calculation is a regular round and then

$$A_{\mathrm{r}} = \frac{I_{\mathrm{S}} h h_{\mathrm{m}} M_{\mathrm{R}} \alpha_{\mathrm{S}}}{4\lambda_{\mathrm{S}}^{2}(T_{\mathrm{S}} - T_{\mathrm{i}})} \varsigma \tag{8.74}$$

where

I_{S} is the stream injection rate, kg/h;
h is effective thickness of the reservoir, m;
h_{m} is enthalpy of saturated steam, decimal;
λ_{S} is thermal conductivity of rocks in top and bottom layer, 10^3 kcal/(h.m.°C);
M_{R} is calorific capacity of the reservoir, 10^3 kcal/(cm^3 °C);
α_S is thermal diffusion coefficient of rocks in top and bottom layer, m^2/h;
T_{S}, T_{i} is steam temperature and initial formation temperature, °C;
t is steam injection time, h;
A_{r} is steam area of the heating area, m^2;
ξ is dimensionless function.

The heating area by calculation is a regular round, while the actual heating area in the oil layer is irregular; therefore, the sweep efficiency E_a is introduced to obtain the maximum heating radius:

$$r_h = \sqrt{\frac{A_r}{E_a \cdot \pi}} \tag{8.75}$$

where

r_{h} is heating radius, m;
D is reasonable well spacing, m.

So, the reasonable well spacing is $d = 2r_{\mathrm{h}}$.

Because of the square well pattern, the reasonable well spacing density is $S = \mathrm{d}^2/1{,}000{,}000$.

where Ea is sweep efficiency, decimal;

S is reasonable well spacing density, km^2/well.

8.4.2 *The Volumetric Method*

The reasonable well spacing density can be determined with the volumetric method by calculating the drainage area of cumulative production in the stimulation period of old wells. The specific calculation formula is:

$$S = \frac{N_{\mathrm{p}} B_{\mathrm{oi}}}{100 h \phi \rho_0 \Delta S_o} \tag{8.76}$$

$$d = 1000\sqrt{S} \tag{8.77}$$

where

N_{P} is average cumulative production of stimulation per well, 10^4 t;
B_{oi} is oil volume factor;
h is reservoir effective thickness, m;
ϕ is average porosity, decimal;
ρ_0 is crude oil density, $\mathrm{g/cm}^3$;
ΔS_{o} is variance of oil saturation at the end of steam stimulation, decimal;
S is the reasonable well spacing density, km^2/well;
d is the reasonable well spacing, m.

8.4.3 The Method of Controllable Reserves Per Well

This method is a relational expression of the well spacing density and recovery degree derived from the formula. Regarding a certain enterprise benefit in oilfield development, the reasonable well spacing density should make the production value of the controllable reserves per well equal to the total investment per well.

Shelkachev's formula is:

$$E_{\mathrm{R}} = E_D \mathrm{e}^{-as} \tag{8.78}$$

The well spacing density s (ha/well) in the formula can be changed into:

$$S' = 100/S \tag{8.79}$$

Substitute it into the previous formula:

$$E_{\mathrm{R}} = E_{\mathrm{D}} \mathrm{e}^{-100a/S'} \tag{8.80}$$

Take the derivation of the well spacing density n at both sides of the equation and reorganize it into:

$$\frac{\mathrm{d}E_{\mathrm{D}}}{\mathrm{d}s'} = E_{\mathrm{D}} \left(\frac{100a}{s'^2} \right) \mathrm{e}^{-\frac{100a}{s'}} \tag{8.81}$$

Both sides are multiplied by the unit area reserves V:

$$\Delta N_k = V \frac{\mathrm{d}E_{\mathrm{D}}}{\mathrm{d}s'} = \mathrm{d}E_D \left(\frac{100a}{s'^2} \right) \mathrm{e}^{-100a/s'} \tag{8.82}$$

where

ΔN_k is recoverable reserves increasement by the unit change of well spacing density in different well spacing density, 10^4 t;
V is producing geological reserves per unit area, 10^4 t/km^2;
E_{R} is oil recovery rate, %;
E_{D} is oil displacement efficiency, %;
s' is well spacing density, well/km^2;
s is well spacing density, ha/well;
A is well pattern coefficient.

The total investment per well is:

$$M = K(1+i)^4 + 8P$$

The coefficient 8 in the formula represents the 8-year payback period.

The total income after recovering 80 % of the recoverable reserves is:

$$C = 0.8B\Delta N_k \tag{8.84}$$

When the investment is equal to the income, i.e., M = C, then

$$K(1+i)^4 + 8P = 0.8B\Delta N_k \tag{8.85}$$

Then,

$$\Delta N_k = \frac{K(1+i)^4 + 8P}{0.8B} \tag{8.86}$$

Substitute (8.86) into (8.82), then

$$\frac{K(1+i)^4 + 8P}{0.8B} = VE_{\mathrm{D}}\left(\frac{100a}{n^2}\right)\mathrm{e}^{100a/n} \tag{8.87}$$

where

M is the increased total investment per well because of the increase of recoverable reserves with the change of well spacing density, 10^4 yuan;
C is the total income per well, 10^4 yuan;
K is drilling and capital investment per well, 10^4 yuan;
P is annual operating cost per well, 10^4 yuan;
i is annual interest rate, decimal;
B is oil price, Yuan/t.

The well spacing density n can be obtained with formula (8.87).

8.4.4 Shelkachev's Iterative Method

After studying more than 130 water-flooding oilfields, the former Soviet expert V. N. Shelkachev put forward the relation between the well spacing density and recovery:

$$E_{\mathrm{R}} = E_{\mathrm{D}}\mathrm{e}^{-aS} \tag{8.88}$$

The above formula shows that, with the infilling of well pattern, the final recovery rate increases, while the development investment is also increasing. When the infilling of well pattern reaches a certain extent, the production value of increasing the oil recovery percent will be less than the investment of infilling the well pattern. Therefore, the reasonable well spacing density is the well spacing density that equalizes the production value with the increase of recovery rate and the investment of well pattern with the changing rate of well spacing density.

Through numerical simulation and physical simulation, it is found that the above relation is also suitable for the steam flooding in heavy oil reservoir.

Both sides of formula (8.88) are multiplied by NB:

$$NBE_{\mathrm{R}} = NBE_{\mathrm{D}}\mathrm{e}^{-aS} \tag{8.89}$$

Obviously, formula (8.89) shows the value of the crude oil that corresponds to a well spacing density S, that is, the total revenue of the reservoir.

Both sides of formula (8.89) are calculated with derivation:

$$\frac{\mathrm{d}BNE_{\mathrm{R}}}{\mathrm{d}S} = -NBE_{\mathrm{D}}a\mathrm{e}^{-aS} \tag{8.90}$$

It is also known that the total investment in the oilfield M is a function of the well (Group) number:

$$M = nb \tag{8.91}$$

and

$$n = A/S \tag{8.92}$$

Substitute formula (8.92) into formula (8.91), then

$$M = Ab/S \tag{8.93}$$

Both sides of formula (8.93) are calculated with derivation:

$$\frac{\mathrm{d}M}{\mathrm{d}S} = -\frac{Ab}{S^2} \tag{8.94}$$

where

b is average single well investment, million yuan;
A is oil area, km^2.

Make the left side of formula (8.94) and formula (8.90) equal, that is, the production value with the increase of recovery rate and the investment of well pattern with the changing rate of well spacing density are equal, then

$$\frac{\mathrm{d}BNE_{\mathrm{R}}}{NS} = \frac{\mathrm{d}M}{\mathrm{d}S} \tag{8.95}$$

Make the right side of formula (8.90) and formula (8.94) equal, then

$$-NBE_{\mathrm{R}}ae^{-aS} = -\frac{Ab}{S^2} \tag{8.96}$$

It can be reorganized into:

$$aS = 2\ln S - \ln\frac{Ab}{aNBE_D} \tag{8.97}$$

This formula is the expression of the well spacing density, related to the reserves, the oil displacement efficiency, the oil price, the oilfield area, and other factors, and it is a transcendental equation, which can be solved by the intersection method and the iteration method. The method is specified as follows:

a. Intersection method

Assume

$$F_1(S) = aS \tag{8.98}$$

and

$$F_2(S) = 2\ln S - \ln\frac{Ab}{aNBE_{\mathrm{D}}} \tag{8.99}$$

Then, the two curves of $F_1(f) \sim S$ and $F_2(f) \sim S$ are drawn in the same coordinates, and the f corresponding to the intersection is the reasonable well spacing density.

b. Iterative method

The well spacing density f can be automatically calculated with Newton's iterative calculation method.

8.4.5 The Injection-Production Ratio Method

The success of steam flooding depends largely on the operation condition of injection-production, which is closely related to the well spacing. According to the successful experience of steam flooding in foreign countries, necessary conditions for the success of the steam flooding are as follows:

a. The steam injection rate of the unit reservoir volume is more than 1.6;
b. The injection-production ratio is more than 1.2;
c. The bottom steam quality is more than 40 %.

According to reservoir engineering theory, the relation between well spacing, steam injection rate and injection-production ratio can be expressed in the following formula:

$$\mathrm{PIR} = \frac{n_r q_L}{q_s} \tag{8.100}$$

The formula for calculating gas injection volume in a well group is:

$$q_s = 10,000 I_s F_A h d^2 \tag{8.101}$$

The well spacing d is:

$$d = 100\sqrt{\frac{n_r q_L}{I_s F_A h \mathrm{PIR}}} \tag{8.102}$$

where

PIR is injection-production ratio of the displacement well group, dimensionless;
n_r is injection-production wells ratio of the displacement well group (1 in five-spot method, 2 in seven-spot method, and 3 in inverted nine-spot method);
q_L is liquid production volume per well, m^3/d;
q_s is well group steam injection rate, t/d;
I_s is steam injection rate of a unit reservoir volume, m^3/(d ha m);
F_A is area coefficient of well group (1 in five-spot method, 2.6 in seven-spot method, and 4 in Inverted nine-\method);
h is effective thickness of reservoir, m;
d is well spacing, m.

8.4.6 The Oil Recovery Factor Control Method

Under an injection-production balance, the oil recovery rate can be calculated by the following formula:

$$V_o = \frac{T I_B S M \rho_o}{A[B_o + f_w/(1 - f_w)]} \tag{8.103}$$

where

V_o is oil recovery rate, decimal;
T is production days per year of oil wells (300), d;
I_B is intensity of water injection, m^3/(d m);
M is injection-to-producing-well ratio;
A is unit reserve factor (=274.52 * 10,000/3.3/10 = 83187.88), t/(km^2 m);

B_o is crude oil volume conversion factor (1.19);
f_w is water cut of oil well;
S is well spacing density, well/km^2;
ρ_o is surface crude oil density (0.87), t/m^3.

When the oil recovery rate is fixed, the well spacing density S can be obtained from formula (8.103).

It can be seen that the oil recovery rate is related to such parameters as the well spacing density, injection-to-producing-well ratio, intensity of water injection, and water-flooding pattern. With the same intensity of water injection, the greater the well spacing density is, the higher the oil recovery rate is.

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