D. O. Volchenko, I. M. Dragan

TECHNOLOGY DEVELOPMENT OF OIL FIELDS

LECTURE NOTES

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The department of petroleum production

D. O. Volchenko, I. M. Dragan

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Рецензенти:

Тарко Я. Б. доктор технічних наук, професор кафедри видобування нафти і газу Івано-Франківського національного технічного університету нафти і газу

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INTRODUCTION

The development of oil fields is called the implementation of a scientifically based process of extracting oil and gas from the depths. The development process consists of drilling the field and developing oil and gas reserves.

"Technology development of oil fields" course - is the field of applied science, as an academic discipline refers to engineering. It provides not only a quality description of the field, but also the quantitative characteristics of the process of extracting oil and gas from the layer. It includes the sections about systems and technologies of development, planning and designing development, actualizing of design solutions, control, analysis and regulation of oil fields development.

The theoretical basis for the development of oil fields are the fundamental principles of the oil layer physics and underground hydro-gas mechanics.

It is difficult to imagine the development of oil fields without geology and geophysics and also without studying the geological structure of the field. It also relies on the important principles of physics and chemistry, mathematical physics, and borehole operation technology.

Design and implementation of the development of oil fields are subordinated to a single goal and require a single methodology that allows you to link all the knowledge about the oil deposit and about the processes occurring inside it during extraction of liquid and gas.

One of the major achievements in the oil field development theory was the determination of the main forces driving oil and gas to the bottom of a borehole, i.e. the foundation of the theory of oil field modes.

The technology of oil field development is an intensively expanding area of science. Its further development will be associated with the use of new extracting technologies of oil from the deposit, new methods for identifying the nature of the in-layer flow processes, managing the development of fields, using advanced methods for exploration and development of fields planning, taking into account data from related sectors of the national economy, using automated systems for managing mineral extraction processes from the depths, the development of methods of detailed accounting of the layers structure.

The goal of mastering the discipline "Technology development of oil fields" is to form students' knowledge, skills and professional competencies in the field of oil field development, familiarize them with the theoretical foundations and modern methods of hydrocarbon production, development systems, calculating and forecasting methods of oil field development processes; methods of control and management of the development process, enhanced oil recovery methods.

§1 SYSTEMS AND TECHNOLOGY DEVELOPMENT OF OIL FIELDS

1.1 Object, system and technology development

Oil field development includes the following steps needed to bring the oil to the surface:

1. Drilling over a reservoir.
2. Control of the movement of oil and gas to the wells by proper spacing patterns and operating conditions.
3. Reservoir energy control.

The development of oil fields offers a set of measures related to the drilling of wells, control filtration flows into the reservoir, the location of wells, setting the mode of operation of wells.

The **"system development"** - commonly understood set of activities carried out in the fields, comprising: 1) drilling deposit; 2) control filtration flows in the reservoir by placing the wells and the default mode of operation; 3) the regulation of energy balance reservoir by pumping water or gas; 4) the rise of liquid from bottomhole to the surface.

The **object development** is artificially allocated within the technological field of education (layer, an array, a set of layers) which contains reserves of hydrocarbons are extracted from the depths of a defined group of wells (Fig. 1.1, Table 1.1).

Main features of the object - its industrial presence in the oil wells and the group with which it developed.

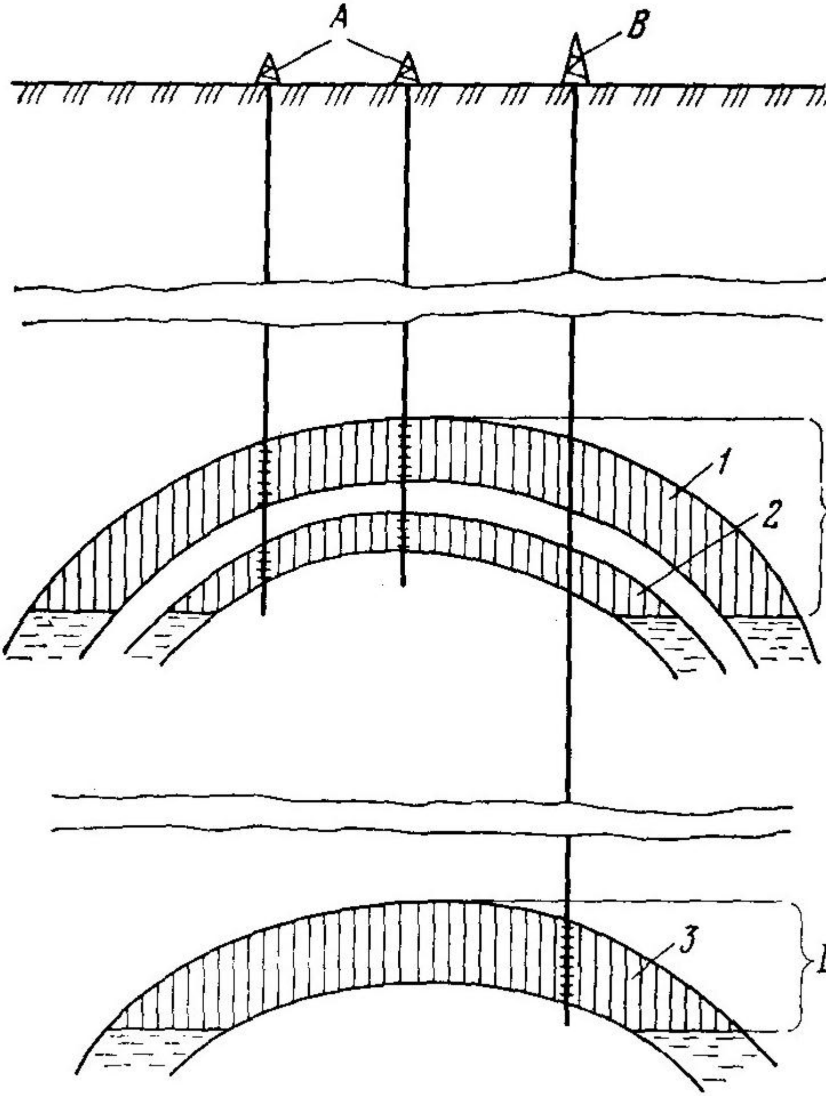


Figure 1.1 - Section of multilayers oil field

Table 1.1 – Characteristics of layers

Geological and physical properties	Layers		
	1	2	3
Recoverable oil reserves, mln. tons	200	50	70
Thickness, m	10	5	15
Permeability, mD	100	150	500
Viscosity, mPa·s	50	60	3

Combining layers 1 and 2 in one object development due to the fact that they have similar values of permeability and viscosity of the oil, and are a short distance from each other vertically. By this recoverable reserves of oil in the reservoir 2 are relatively small.

In addition, if the layer 3 contains low-viscosity oil can be developed using conventional water flooding, then the development of layers 1 and 2, which marked the high-viscosity oil, will have to apply from the beginning of the development of other technology.

However, it should be noted that despite the significant difference of parameters of layers 1, 2 and 3, the final conclusion of the selection of objects taken from the development of technology and technical and economic indicators of options combining layers in object development.

Objects development is divided into the following types: **independent**, that is being developed now and **back object**, that is the one that will be developed wells are currently operating in another object.

The main purpose of the theory and practice of oil field development - the most complete and cost-efficient extraction of oil from the depths.

Discipline "Technology development of oil fields" is technology because it is directed at improving technology, increasing real economically profitable oil recovery.

Oil recovery factor. Determines the degree of extraction of oil from oil reservoirs and is a measure of the degree of oil usage. Getting maximum value - it is one of the main objectives of the rational development of oil fields. Oil recovery factor - its ratio of oil produced reserves to the initial oil reserves in the reservoir. Initial oil reserves are defined by the volumetric method (Zhdanov's formula)

$$Q_{init} = F \cdot h \cdot m \cdot \rho_0 \cdot \theta \cdot \gamma, \text{ tons} \tag{1.1}$$

where F - oil-bearing area, m^2; h – effective layer thickness, m; m – coefficient of porosity, fractions of unity, (f.u.); ρ_0 - initial oil saturation, (f.u.); θ - average recalculating factor, (f.u.); $\theta=1/b$ (b – volume formation factor); γ - specific density of oil after decontamination, t/m^3.

Coefficient of oil recovery depends on many factors: the geological structure and mode of deposit; properties of rocks-collector; its degree of heterogeneity; properties of reservoir fluids, indicators development, drives reservoir and others. Oil recovery factor depends on the amount of free gas, which is in the reservoir. For determination of oil recovery used in industrial and laboratory methods.

What does it mean developing reservoir? Developing a reservoir to cause movement of reservoir fluids into wells. This can be done by drilling and injection wells operating. You need only install the needed their number, location, time of commissioning and operating modes.

These issues must be addressed in the design of field development system, and the system is designed to be rational. In justification Selecting and development field governed by criteria of rationality.

What is a rational development system? Rational development system - a system that provides the needs of the state in the oil at the lowest cost possible and high oil recovery.

In establishing these criteria the following basic points must be considered:

1. The minimum degree of well interaction.
2. Maximum recovery factor.
3. Minimum production cost.

A rational development plan must ensure the prescribed production at minimum cost and with the highest possible recovery factor.

Planning the development system consists of selecting a variant which meets all the above requirements. On this basis the problem of establishing a rational development plan should be subdivided into a number of problems to be solved one after another:

- establishing the geological-physical data;
- establishing the technical indices for some particular development plan by means of hydrodynamic calculations;
- evaluating the economic effectivity of the different development plans;
- choosing the most rational development plan by comparing the geological- technical and economic characteristics involved in different plans.

To select rational development field conditions at the design stage different options for development are calculated. Options are not only for systems development or by action on the layer but the parameters for the development of the same systems.

What is the technology of extracting oil from the depths? The technology of extracting oil from the depths defined mechanism that drives the oil and gas in the reservoir. In natural conditions, this oil displacement by water or gas contained in the gas cap or released from oil. Performance Technology development is characterized by the fullness of the extraction of oil. In order to increase oil recovery using various methods of influence on them, water injection, gas and various chemicals, coolants and others.

What is called the technology development of oil fields? Technology development of oil fields is the set of methods used to extract oil from the depths.

How can you regulate the process of field development? The process governing the development of the field, changing the total number of wells, the ratio producing and injection wells, their relative position in the square, setting various modes wells during their operation.

The diversity of geological and physical conditions in which the process of development of oil fields requires the use of different oil recovery technology and various systems development.

At one and the same the deposit depending on the location, number, order commissioning and mode of production wells, and depending on the application download working agent into the reservoir and pumping system can hold various processes put operation with different rates of development.

1.2 Basic geological data for development planning

A geological survey of an oil reservoir should establish the following data that characterise the productive intervals.

1. The geometry of the formation, i.e. its structure, thickness, division into separate interstratified layers, communication between the layers, and drainage boundary.

These data are usually presented in graphic form: structural charts including contour diagrams of the reservoir, isopachous maps, geological sections. The geometrical data serve as a basis for calculating the reserves and establishing the well spacing patterns.

2. Sources of reservoir energy are established by comparing the initial formation pressure with the saturation pressure, and also by establishing the dimensions of the entire water drive system, the existence of an encroachment zone and the degree of its activity. On the basis of the study of the energy characteristics of the reservoir, it is possible to establish the need for pressure maintenance operations in order to create an artificial driving mechanism. Different reservoir drives are characterised by different recovery factors which are used in calculating the available oil reserves and the producing life of a reservoir.

3. The initial reservoir pressure and the permissible pressures in producing wells during the production period determined by the saturation pressure, the minimum free-flow pressure, and also by technical factors (a type of well, the stability of the collector rock and others). **The maximum permissible withdrawal** is usually determined by the stability of the collector rock and the strength of the casing.

The minimum permissible bottom-hole pressure or the maximum permissible rate of withdrawal are the limiting conditions in reservoir development planning.

4. The physical characteristics of the rock: permeability, porosity, elasticity and mechanical composition which are used in various hydrodynamic calculations.

5. The physicochemical properties of the fluid and gas at formation pressure and temperature are determined by examining bottom-hole oil samples. This data is used both in hydrodynamic calculations and in estimating the commercial grade of the oil. The saturation pressure is often taken as the limiting condition of well performance.

The solubility factor, the initial gas saturation of the oil, and the oil-to-gas viscosity ratio are used in calculations employed in investigating the development of a solution gas drive in a reservoir.

6. The formation piezoconductivity factor characterises the rate of transmission of pressure in the formation and is used in investigating the elastic properties of the formation and fluid.

The validity of the development plan depends on the completeness and accuracy of the geological-physical survey of the reservoir.

Inadequate initial data hampers the plotting of isopachous, permeability, porosity and piezoconductivity graphs and make it necessary to rely on average data in hydrodynamic calculations.

Reservoir development planning should be based on data from test wells drilled to the productive strata, which upon sampling produced oil, water and gas.

Surveys of all the wells of a field should cover the following points:

1. Core sampling. This should include continuous cores of the productive strata. Cores are used for determining the physical and lithological characteristics of the strata.

2. Electrical loggings, laterlog and well-deflection measurements which are used to construct maps and profiles. For greater accuracy, electrical logging should be correlated with the cores.

3. Neutron and gamma-ray logging to establish more positively the structure and physical characteristic of the formation.

4. Deep sampling of oil, gas and water under formation pressures. Laboratory analysis of such samples under formation temperatures are conducted to determine the physicochemical characteristics of the reservoir fluids.

5. Formation pressure measurements. Well flow surveys under different conditions of operation. Establishing the relationship between flow and bottom-hole pressure. Determining well productivity indices and formation permeability on the basis of the well surveys.

6. Recording curves of bottom-hole pressure restoration in shutting wells and processing of the curves to calculate the piezoconductivity and permeability factors, and the reduced radius of the well.

7. Surveys of the well interaction to establish the degree of communication between different formation strata or the pinching out of individual layers from one another. The qualitative characteristic of the communications within the formation and also the piezoconductivity factors are determined on the basis of the nature of the interaction.

8. Observations of sand carry-over during operation of the well under various conditions and determination of maximum permissible withdrawals.

9. Analysis of the salt composition of the waters and the water pressure head in the reservoir.

From this list of the essential surveys, it will be seen that most of them are interrelated. In order to carry out these surveys by means of exploratory wells within a short period of time, it is necessary to prepare a plan with a detailed timetable.

When initial geological and physical data obtained from drilling logs and sampling and surveys are available, it is possible to perform the required hydrodynamic calculations and thus establish the technical characteristics of the development plan.

§2 INDICATORS OF DEVELOPMENT

2.1 Indicators of oil field development

To characterize the process of extracting oil from the depths using indicators that determine the time intensity, the degree of extraction of oil, water and gas. Among the indicators of development are the following.

Production oil Q_{oil} - the main indicator, the total for all producing wells drilled in the object per unit time, and **average daily production** - mining, which accounts for one well. The variation in time of these indicators depends not only on the properties of the reservoir and fluid but also from manufacturing operations which are carried out in the fields at various stages of development.

Production liquid Q_{lig} - the total production of oil and water per unit time. From purely petroliferous wells in the reservoir for some time (waterless period of operation of wells) producing clean oil. For most fields, sooner or later their production begins to increase the water content. Since then, the production liquid exceeds oil production.

Considered indicators reflect the dynamic characteristics of the process of producing oil. To characterize the development process for the entire past period of time using the integral indicator - **summary production.**

There are the following parameters: **summary production oil**, **liquid** and **water**. **Summary production oil (liquid, water)** reflects the amount of oil (liquid, water), which is extracted by the object for a certain period of time from the beginning of development, i.e. since the start of the first production well.

Unlike dynamic indicators, summary production can only increase.

It is absolute indicators. But there are also relative indicators which characterize the process of extraction products in parts of the initial oil reserves. One of the important indicators of technological development of oil deposits is **rate development**.

This indicator varies over time, reflects the impact on the development of all technological operations carried out on the field. Using the indicator is obtained graph.

There are four periods of the oil field, called stages (Fig. 2.1).

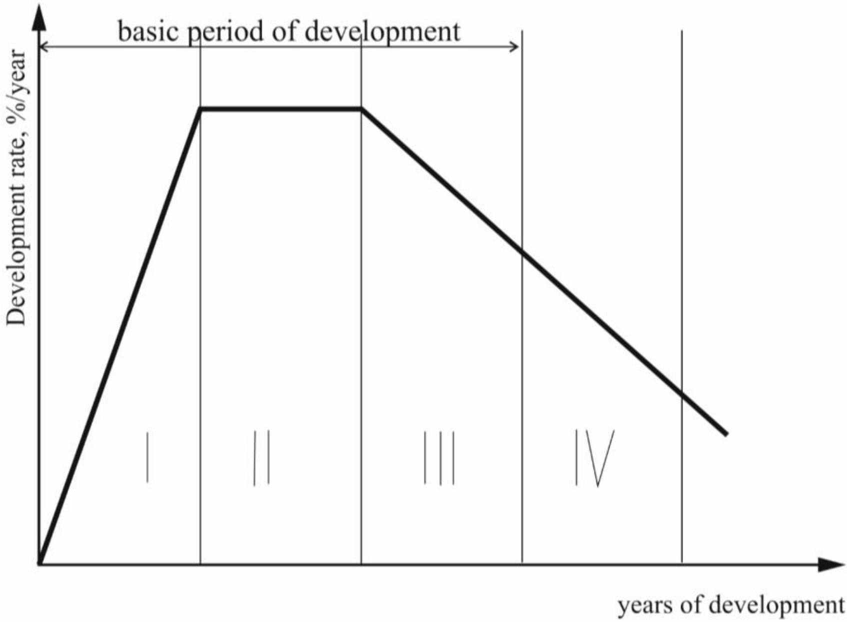


Figure 2.1 – The periods of the oil field

The first stage *(stage input field operation)* when taking place intensive drilling of the main amount of wells, the rate of development continuously increases. During this phase mined usually oil without water. The duration of the stage depends on the size of the deposit and the rate of drilling. Duration of the stage is 4-5 years, depending on the rate of drilling deposit.

The second stage *(the stage reached by maintaining the maximum level of oil production)* is characterized by more or less stable annual oil extractions. The main objective of this phase is done by drilling reserve fund regulation modes of development wells and the full system flooding or other method action on the layer. Some wells by the end of the stage stop and gush their way transferred to mechanized operation. The main task - to support high levels of oil production for a longer period. The duration of the stage - 5-7 years, with the larger oil viscosity, the shorter duration of the second stage.

The third stage *(stage falling production oil)* is characterized by intense slowdown rate development, progression to the product water content of 80-85%. Because water content is reduced through disconnection well stock wells, almost all the amount of well transferred to a mechanized method of operation. The main task of this stage - slow down the fall in oil production.

The main objectives are to reduce the production of formation of water through insulation work. The duration depends on the stage of preliminary stages and durations of 5-10 years or more.

The fourth stage *(final stage of development)* is characterized by slow rate development. Amount of water in oil is high and slowly increases decreases operating well stock. During this stage carry large amount of repair work. The duration of the fourth stage of 15-20 years and more.

Formation pressure P_f - the pressure at which oil and gas are found in the reservoir.

Amount of wells n - the total amount of injection and production wells that are designed to carry out the development process. The number of wells divided into **primary** and **backup**.

Gas-oil factor (gas-oil ratio) G - the ratio of the extracted gas to the amount of oil produced

$$G = \frac{Q_{gas}}{Q_{oil}}, \text{ m}^3/\text{m}^3; \text{ m}^3/\text{t}.$$

Water-cut (amount water in oil) n_w - the ratio of water flowrate to the total flowrate of oil and water.

$$n_w = \frac{Q_w}{Q_{liq}} = \frac{Q_w}{Q_{oil} + Q_w}, \text{ \% or f. u.}$$

Amount of substances pumped into the reservoir. In implementing different technologies to effect on the layer using different agents that improve conditions for extracting oil from the depths. Pumped into the reservoir water, steam, hydrocarbon gases and other substances. The injection rate these substances and their total amount and rate at which they extract the surface with production wells - important indicators of the technological development process.

2.2 Reservoir energy and forces operative in reservoirs. Oil recovery under different drives

Fluids flow to oil and gas wells because of the differential between the formation and bottom-hole pressures. The magnitude of this pressure differential depends on the rate of liquid (or gas) withdrawals from the well, the physical properties of the reservoir rocks and fluids and also on the type of reservoir energy that causes oil and gas to move.

Until quite recently, it was considered that the influence of each well extends to a comparatively small area of the formation around the bottom hole so that each well had a limited drainage area. This view proved to be erroneous. It is now definitely established that the whole area of every oil and gas reservoir, together with the wells constitutes a single hydraulically interconnected system (unless, of course, the formation is split up into separate blocks by tectonic dislocations). Thus the influence of producing wells drive area, right up to the boundaries of the reservoir.

Hence it follows that the type and reserves of energy and forces operative in the reservoir that drives the oil and gas to the bottom holes of wells must be considered in the structure of the entire reservoir and of the adjacent areas, and also in relation to the properties of the reservoir fluids and the rocks of the entire reservoir.

Every oil and gas reservoir has an initial energy reserve. This energy reserve is consumed in moving the oil and gas through the formation to the well. The energy reserve of a reservoir depends on the magnitude of formation pressure. In the general case, the sources of reservoir energy, which cause oil and gas to flow to the well are:

- the elastic energy of compressed reservoir rocks and fluids;
- the energy of free gas and of the gas evolving from the oil when pressure is reduced;
- the potential energy of water encroachment;
- the potential energy of the static pressure of the oil itself due to gravity.

During the exploitation of a field, the reserves of reservoir energy are consumed in overcoming forces that resist the movement of oil and gas through the formation: forces of internal friction of liquids and gases and of their friction with the rock, and also capillary forces. Frictional forces arise due to the viscosity of the fluids.

There may be a single dominant type of reservoir energy, driving the oil and gas, or else they may be driven by a number of forces. Further on it will be shown that the energy characteristics of a reservoir determine the entire process of development and exploitation.

Let us consider in greater detail the nature and the character of manifestation of the types of reservoir energy mentioned above. There are **6 oil reservoir drives:**

- **elastic drive;**
- **solution gas drive;**
- **water drive;**
- **gas cap drive;**
- **gravity drive;**
- **combination drive.**

The drive of a reservoir is determined both by conditions created artificially as a result of the development and the production of a reservoir and also by natural conditions. A particular mechanism of a reservoir drive may be established, maintained, controlled and even replaced by a different mechanism. It depends to a large extent on the rate of fluid and gas withdrawals and on artificial measures carried out during the exploitation of the reservoir (such as injecting a driving agent into the reservoir). Geological conditions and the specific source of formation energy only help to establish a particular driving mechanism but do not only fully determine it.

Elastic drive. *Condition elastic drive* - excess reservoir pressure above the saturation pressure. Bottom-hole pressure is not less than the saturation pressure.

Oil is a single-phase state. The influx of oil to the wells is due to the elastic properties of reservoir rocks and fluids.

In the case of an *elastic-water drive*, the changes observed in the reservoir behaviour are of a different nature. A typical feature of the elastic-water drive mechanism is a decline in pressure during the initial period. Thereafter, if fluid withdrawals remain constant, the rate of pressure decline tapers off. This is due to the fact that with time, the zone of reduced pressure extends to an ever-increasing area of the reservoir, and to maintain a given influx of fluid by the elastic expansion of the reservoir rocks and fluids a smaller pressure decline is required than in the initial period. If the bottom-hole pressure is maintained constant, the flow at the wells at first diminishes rapidly, but later on, the rate of decrease tapers off. The elastic properties of reservoir rocks and fluids are nicely characterised by the fact that any change in pressure at any point in the reservoir is not transmitted through the formation instantaneously but at a certain rate (Fig. 2.2).

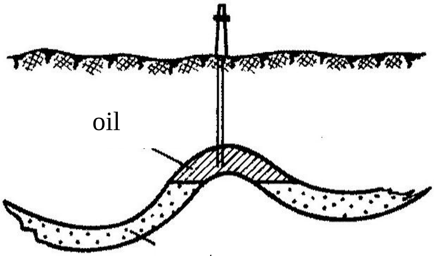


Figure 2.2 – Elastic-water drive

When disclosure well oil reservoir under the action of elastic expansion will initially sail up the hole with sites located in very close proximity to the hole. But because of the oil from these sites arrives into the well, the pressure in them decreases, which in turn causes the inflow of oil from more remote areas. This process will evolve over time, and at some point, the pressure begins to fall in the aquifer of the reservoir. Since then, the water from the aquifer region will begin to enter the reservoir area previously occupied by water and displace the oil towards the well.

Solution gas drive (or **dissolved gas drive).** Occurs when the reservoir pressure is less saturation pressure and gas bubbles released from the oil at lower pressure expands, to displace oil wells (in the reservoir moves carbonated oil). Solution drive found in deposits, which initially oil saturated gas. Due to the high mobility of the gas efficiency solution gas drive is small. Solution gas drives are found in saturated reservoirs, in which the initial pore pressure is above the bubblepoint (Fig. 2.3).

In a solution gas drive lighter hydrocarbon components that exist as a liquid in the reservoir before it is produced come out in the form of gas as the reservoir produced. The dissolved gas coming out of the oil expands. In solution gas drive reservoir pressure declines rapidly and continuously and wells generally require pumping or some other artificial lift at an early stage. The gas-oil ratio is lowering slowly, then rises to a maximum and drops.

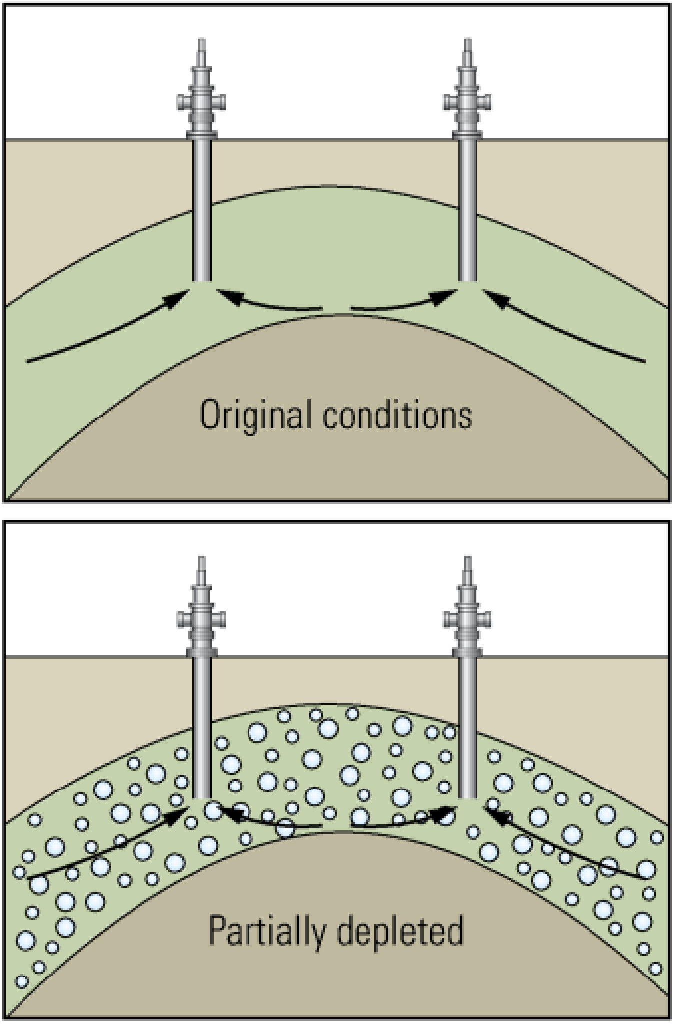


Figure 2.3 - Gas in the saturated oil of a solution-gas drive system comes out of solution after the reservoir pressure drops below the bubblepoint

Water drive. Oil displaced under the pressure of natural or artificial water download at a pressure above the saturation pressure. In *natural water drive* systems (Fig. 2.4), the oil is driven to the bottom hole under the natural pressure of edge water. A water drive can also be created *artificially* by injecting water through special injection wells (Fig. 2.5).

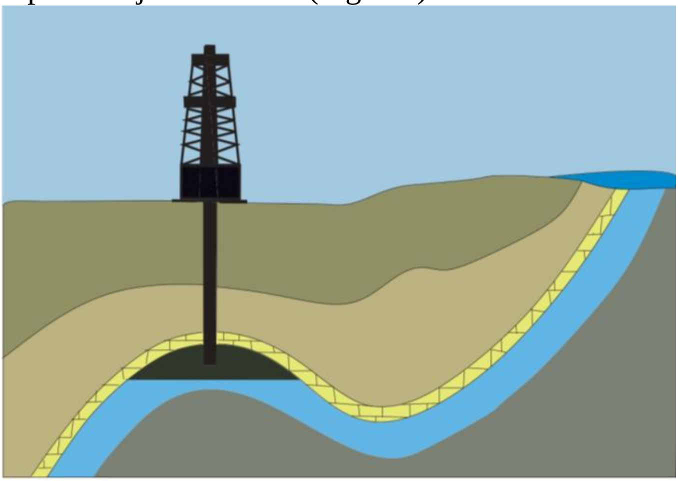


Figure 2.4 – Natural water drive system

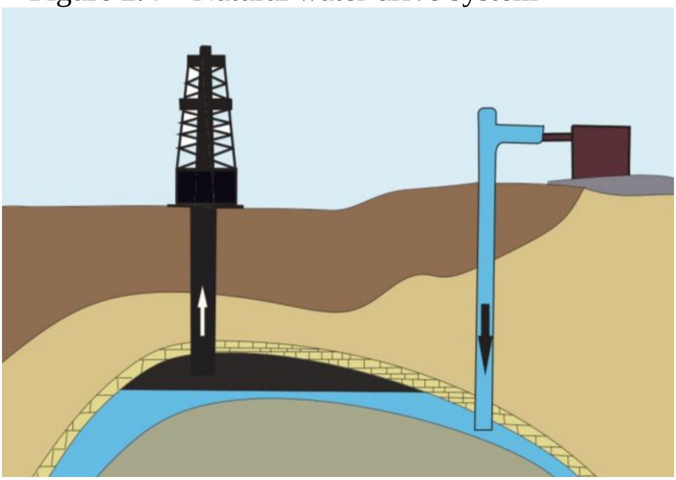


Figure 2.5 – Artificial water drive system

In the case of a water drive in its pure form, oil withdrawn from the reservoir is displaced, volume for volume, by encroaching water. The perimeter of the oil drainage boundary then continuously shifts and contracts. During the exploitation of a water drive reservoir, there is first observed a certain decline in reservoir pressure establishing a pressure differential which causes the encroachment of water on the productive zone. The stabilization of reservoir pressure with time in the case of a steady rate of oil production proves that water drive operates with complete replacement of the withdrawn oil by water. However, if the rate of oil withdrawals from the reservoir continually increases, a time may come when at the given pressure, through the capacity of the water drive system becomes inadequate and the volume of water entering the reservoir is less than the volume of oil withdrawals. In this case, reservoir pressure begins to decline and the water drive mechanism may be replaced by the solution gas drive. As a result of the slow decline in reservoir pressure in water drive reservoirs production from wells remains steady for a long time. The gas factor too usually remains constant until the pressure at bottom holes drops below saturation pressure.

In **gas cap drive** reservoirs the process of displacement of oil by the expanding gas is usually accompanied by gravity effects: the oil flows by gravity to the lowest parts of the reservoir and the gas released from solution rises to the upper zone and replenishes the gas cap. These effects are the more pronounced the greater are the angle of dip of the strata, the permeability of reservoir rock, and the lower the rate of liquid withdrawals, i.e., the rate of filtration. The replenishment of the expanding gas cap by the gas evolving from solution slows down the rate of decline of reservoir pressure. Gravitation segregation of oil and gas in gas cap reservoirs is also largely responsible for the fact that the gas-oil ratio of wells remote from the gas zone of the reservoir can remain low for a long time. In wells which are close to the gas-oil contact, the gas-oil ratio usually increases rapidly, so that ultimately the wells may begin to produce gas alone. Under favourable geological conditions, these gravitational effects may result in the appearance of a gas cap even where there was none originally and then the reservoir operates mainly by the energy of gas released from solution, i.e., by a solution gas drive mechanism (Fig. 2.6).

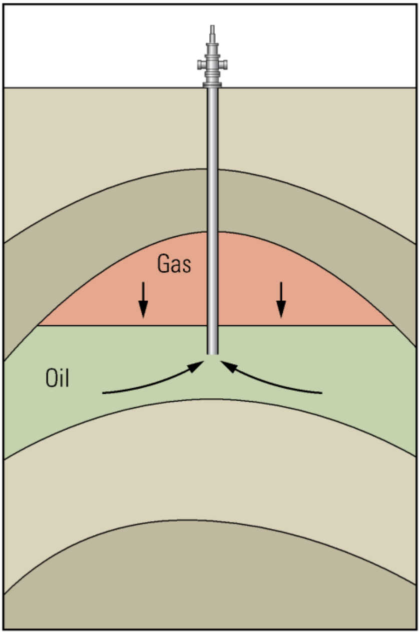


Figure 2.6 - Gas cap drive is energized by expanding gas that fills the voids that occur after liquids are removed

The **gravity drive** is due to the fact that oil-bearing formations are not horizontal but tilted. The magnitude of the static pressure then depends upon the angle of the dip of the strata. In low-dipping strata, the oil can also flow to the wells by gravity, particularly in thick formations. The level of fluid in the reservoir then drops below the capping, this being the case of movement of fluid with a free surface. In some cases, gravity is the only type of energy causing the oil to move to the wells. This occurs most frequently in closed-type deposits after prolonged exploitation when the energy of gas drive has been depleted.

Combination drive. Depletion and water drives can be characterized as pure drive mechanisms; however, another drive is one that can best be described as a combination drive. One such drive has a gas cap above the oil and water below it. Both the gas cap and the water drive the oil into and up the wellbore to the surface. Another type of combination drive has gas dissolved in the oil with water below it. Both the water and the gas coming out of solution drive the oil to the surface.

Oil recovery under different drives.

The oil recovery factor of a reservoir, defined as the ratio between recovered oil and the initial reserve of oil.

According to the experimental and statistical field data, the recovery factor may have the following values depending on the expulsive forces operative in the reservoir:

elastic-water drive ….. 0.4-0.7
solution gas drive …... 0.05-0.3
water drive …………. 0.5-0.8
gas cap drive ……….. 0.1-0.4
gravity drive ……….. < 0.1

The highest recovery factor is assured by the water drive since in this case the oil is displaced by water, the viscosity of which under reservoir conditions may be greater than that of the oil. In any case, the viscosity of water is many times greater than that of gas. It is known that the greater the viscosity of the displacing agent in relation to that of the oil, the greater is oil recovery. When water drive reservoirs are produced for a long time (until the water breaks through into the wells), there is a single-phase movement of the oil in the oil-bearing part of the reservoir as it is displaced by the water acting, as it were, like a piston.

In the case of a gas cap drive oil recovery is somewhat lower than with a water drive because in this case oil is displaced by gas which is of considerably lower viscosity than oil and does not wet the rock. In such cases, even a small decline in reservoir pressure results in the release of gas from the oil which reduced the phase permeability to oil. However, when the dip of the strata is rather steep (not less than 12-15°) and other conditions are favourable to gravitational segregation of oil and gas, the oil recovery factor may be rather high.

Very low oil recovery factors are observed when solution gas supplies the main driving force. In this case, a considerable part of the energy of the expanding gas is spent on slippage to the bottom holes without performing any useful work in displacing oil.

Besides high recovery rates, deposits with pressure drives are usually characterised by a high production rate and a relatively short producing life. Therefore, in the field practice, it is extremely important already at the initial stage of production of a reservoir to determine its natural potential and to decide on a general development plan accordingly. It is exceedingly important to establish the nature of the sources of reservoir energy operative in the given reservoir, the possibility of utilising natural energy to achieve maximum oil recovery or the necessity of supplementing this energy artificially by injecting some kind of a driving agent into the reservoir to secure more effective drainage.

§3 MAIN HYDRODYNAMIC CALCULATIONS FOR DIFFERENT DRIVES

§3.1 MAIN HYDRODYNAMIC CALCULATIONS UNDER WATER DRIVE

Zone existence of water drive is above the saturation pressure it is characterized by constancy formation pressure, which is achieved due to penetrating of water in the oil reservoir or by pumping water from the surface. The theoretical basis for the calculation of development is discipline “Underground hydrogasmechanic“.

The modern designing of oil and gas fields calls for simple calculations using licensed software and powerful computing facilities. However, simple models that we consider enable quality results quickly without long calculations based on more complex models.

3.1.1 Schematization terms of development

Oil deposits have in terms of irregular geometric shapes, and usually have a complex geological structure and the irregular configuration, the thickness of the reservoir is inconsistent in size, unequal is and properties of the reservoir (porosity, permeability, oil saturation) variety may be the properties of oil on different parts of the deposit. This complicates the calculations in the design development of oil fields. The development put the wrong geometry analytically cannot be calculated accurately. For the approximate solving of this problem possible approximation of the actual deposit shapes such forms or parts of forms that are subjected to analytic calculation. In the calculations have to be subjected to the schematic design conditions, use model layer and liquid filtration processes in porous media. From the degree of approximation to the real conditions of the model depends on the accuracy of technological parameters of field development.

When selecting and evaluating design options using simple models, the calculation of technological parameters for the selected option - a complex that specified as the receipt of additional data field when drafting the development. Schematization is performed in four stages:

- schematization form deposit;

- schematization circuit WOC;

- built spatial problem to the plane. Formation and bottom-hole pressures seams in the wells reduced to one plane (usually to the initial level WOC);

- parameters of layer and properties of formation fluids. Different circuit models of the reservoir, which are chosen depending on the degree of scrutiny and put the design phase, homogeneous layer, uniform area-layer, heterogeneous continuum of level-permeability and thickness of the layer of natural or probable distribution of these parameters.

Schematization forms deposits

In practice, there are examples of different forms: stripes, circles, ellipses shaped and their various combinations.

Any form of lay mainly in the calculations can be made to a strip or circle, or to a combination of these forms.

Schematization forms of oil are to replace the complex configuration put on deposit in the form of strips, rings, circle or a set of simple geometric shapes.

If the deposit for which hydrodynamic calculations performed is oval in shape, with the ratio of the axes A:B > 3 (where A – length of deposit, B - width of deposit), then the deposit is schematized by strip (Fig. 3.1).

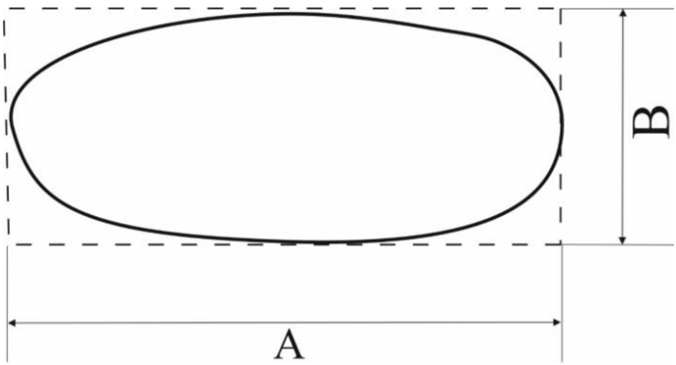


Figure 3.1 - Schematization forms deposits (strip deposit)

In order to calculated indicators met the real, in terms of schematic design must adhere to the following conditions:

1) reserves oil of real and schematic deposits should be the same;

2) perimeters of real and schematic deposits should be the same;

3) a number of wells schematic and real deposits must be the same.

Oval deposit, in which A:B < 3, schematized is ring or circle (Fig. 3.2).

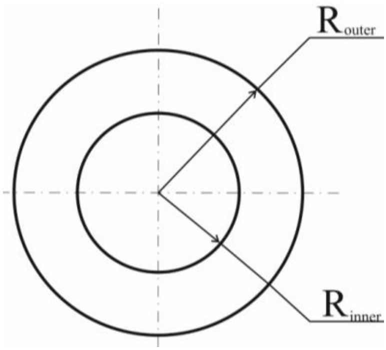


Figure 3.2 - Schematization forms deposits (circle deposit)

After completing schematic terms, we write

$$R_{outer} = \frac{P}{2\pi},$$

where P - the real perimeter of the oil deposit.

$$R_{inner} = \sqrt{R_{outer}^2 - \frac{F}{\pi}},$$

where F – the real area of the oil deposit.

If the real reservoir has a complex configuration, such deposit is schematized several elements square regular geometric shapes (Fig. 3.3). For example, we have

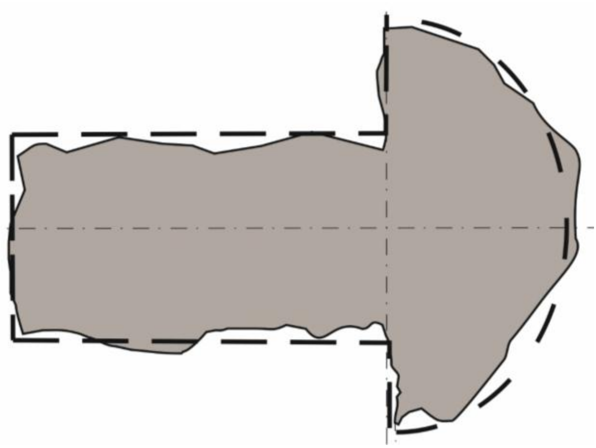


Figure 3.3 – Schematization complex forms deposits

This deposit is schematized in a strip and a semicircle. Calculations are made to strip and circle.

3.1.2 Method of electrohydrodynamic analogy (EHDA) for solving hydrodynamic tasks

Simulation of hydrodynamic processes in the reservoir electric model is based on the analogy between hydrodynamic and electrical processes that have similar equations and describing both systems.

We write the equation of fluid inflow

$$Q = k_0 \Delta P = \frac{\Delta P}{1/k_0} \ , \tag{3.1}$$

where k_0 - productivity coefficient.

Write Ohm's law

$$I = \frac{\Delta u}{R}. \tag{3.2}$$

Making an analogy between the equations (3.1) and (3.2) we see that the analogy between hydrodynamic and electrical parameters is shown in the following:

change in voltage between nodes electricity grid Δu similar to the pressure, that is

$$\Delta u \simeq \Delta P;$$

current, which flows between the nodes of the grid is proportional to the amount of fluid that flows between the regions of the reservoir, that is

$$I \simeq Q.$$

Finally, by analogy $R \simeq 1/k_0$. This value is called the filtration resistance.

The principle (EHDA) is based on generalization electric current laws and fluid flow in porous media. The principle is based on the community mathematical description of the processes occurring in the reservoir during the filtration process of fluids flow of electric current.

Based on the method (EHDA) professor Y. Borisov has developed a method of assembling the hydrodynamic equations for calculation processes of oil fields in the certain placement of wells. Using this method, you can easily make a determination equation flowrates and bottom-hole pressures for any of the options strip or circular rows of wells.

3.1.3 Hydrodynamic calculations flowrates and bottom-hole pressures, and also validities of water-oil displacement without phase permeabilities

The task is solved for two cases, when specified bottom-hole pressures and need to find flowrates or vice versa when specified flowrates, and the need to find bottom-hole pressures. Chance is another task statement when some asked find bottom-hole pressures and flow rates in other rows of wells.

Example 1. We have strip deposit, which is being developed by three rows of wells. Define flowrates rows of wells, if known: bottom-hole pressures in the rows of wells, reservoir parameters and reservoir fluids and a number of wells (Fig. 3.4).

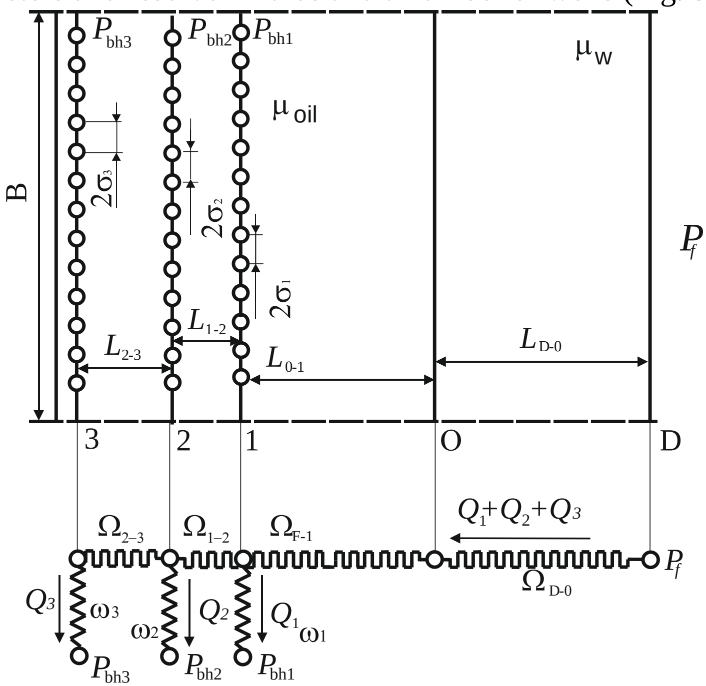


Figure 3.4 – Gydrodynamic and electrical schemes of strip deposit which is developeted by three rows of wells

Inflow to all wells can be seen as a parallel connection of conductors with identical resistances (Ω + ω). Sophisticated filtering right seams between injection rows and production wells are presented using simple filtration flows.

Thus, the filtration inflow into the well can be submitted electrical equivalent circuit for calculating the resistance and use Ohm's and Kirchhoff's laws. Drawing calculation equation system development processes based on the second Kirchhoff's law.

We write equations (we have 3 equations - number of equations in the system equals the number of rows of wells)

$$\begin{cases} P_f - P_{bh1} = (Q_1 + Q_2 + Q_3)\Omega_{D-0} + (Q_1 + Q_2 + Q_3)\Omega_{0-1} + Q_1\omega_1 \\ P_f - P_{bh2} = (Q_1 + Q_2 + Q_3)\Omega_{D-0} + (Q_1 + Q_2 + Q_3)\Omega_{0-1} + \\ \qquad + (Q_2 + Q_3)\Omega_{1-2} + Q_2\omega_2 \\ P_f - P_{bh3} = (Q_1 + Q_2 + Q_3)\Omega_{k-0} + (Q_1 + Q_2 + Q_3)\Omega_{0-1} + \\ \qquad + (Q_2 + Q_3)\Omega_{1-2} + Q_3\Omega_{2-3} + Q_3\omega_3, \end{cases} \tag{3.3}$$

where P_f – pressure drainage boundary (formation pressure), Pa; P_{bh1}, P_{bh2}, P_{bh3} - bottom-hole pressures the first, second and third rows of wells, Pa; Q_1, Q_2, Q_3 – flowrates the first, second and third rows of wells, m^3/s; Ω_{D-o}, Ω_{o-1}, Ω_{1-2}, Ω_{2-3} - external filtration resistances, Pa·s/m^3; ω_1, ω_2, ω_3 – internal filtration resistances, Pa·s/m^3.

External filtration resistances for the strip deposit are defined by formulas (3.4)-(3.7)

$$\Omega_{D-0} = \frac{\mu_w l_{k-0}}{Bkh}; \tag{3.4}$$ $$\Omega_{0-1} = \frac{\mu_{oil} l_{0-1}}{Bkh}; \tag{3.5}$$

$$\Omega_{1-2} = \frac{\mu_{oil} l_{1-2}}{Bkh}; \tag{3.6}$$ $$\Omega_{2-3} = \frac{\mu_{oil} l_{2-3}}{Bkh}; \tag{3.7}$$

where μ_w, μ_{oil} – coefficients of dynamic viscosity of water and oil, respectively, Pa·s, for water μ_w=1 mPa·s; l_{D-0}, l_{0-1}, l_{1-2}, l_{2-3} – distances, m; B – width of deposit, m; k – coefficient of permeability, m^2; h – layer thickness, m.

Internal filtration resistances not depend on the form of deposit and defined by formulas (3.8)-(3.10)

$$\omega_1 = \frac{\mu_{oil}}{2\pi k h n_1} \ln \frac{\sigma_1}{\pi r_{r\,w1}}; \quad (3.8) \quad \omega_2 = \frac{\mu_{oil}}{2\pi k h n_2} \ln \frac{\sigma_2}{\pi r_{r\,w2}}; \quad (3.9)$$

$$\omega_3 = \frac{\mu_{oil}}{2\pi k h n_3} \ln \frac{\sigma_3}{\pi r_{r\,w3}}; \quad (3.10)$$

where σ_1, σ_2, σ_3 - the half distance between the wells for each row, m; n_1, n_2, n_3 - amount of wells in each row.

Half distance between the wells is defined by the formula

$$\sigma_i = \frac{B}{2n_i}.$$

Solving equation (3.3) determine the flowrates of rows of wells.

The system of equations (3.3) can make another method

$$\begin{cases} P_f - P_{bh1} = (Q_1 + Q_2 + Q_3)\Omega_{D-0} + (Q_1 + Q_2 + Q_3)\Omega_{0-1} + Q_1\omega_1 \\ P_{bh1} - P_{bh2} = (Q_2 + Q_3)\Omega_{1-2} + Q_2\omega_2 - Q_1\omega_1 \\ P_{bh2} - P_{bh3} = Q_3\Omega_{2-3} + Q_3\omega_3 - Q_2\omega_2. \end{cases}$$

Example 2. We have circle deposit, which is being developed by two rows of wells. Define bottom-hole pressures in the rows of wells, if known: flowrates rows of wells, reservoir parameters and reservoir fluids and the number of wells (Fig. 3.5).

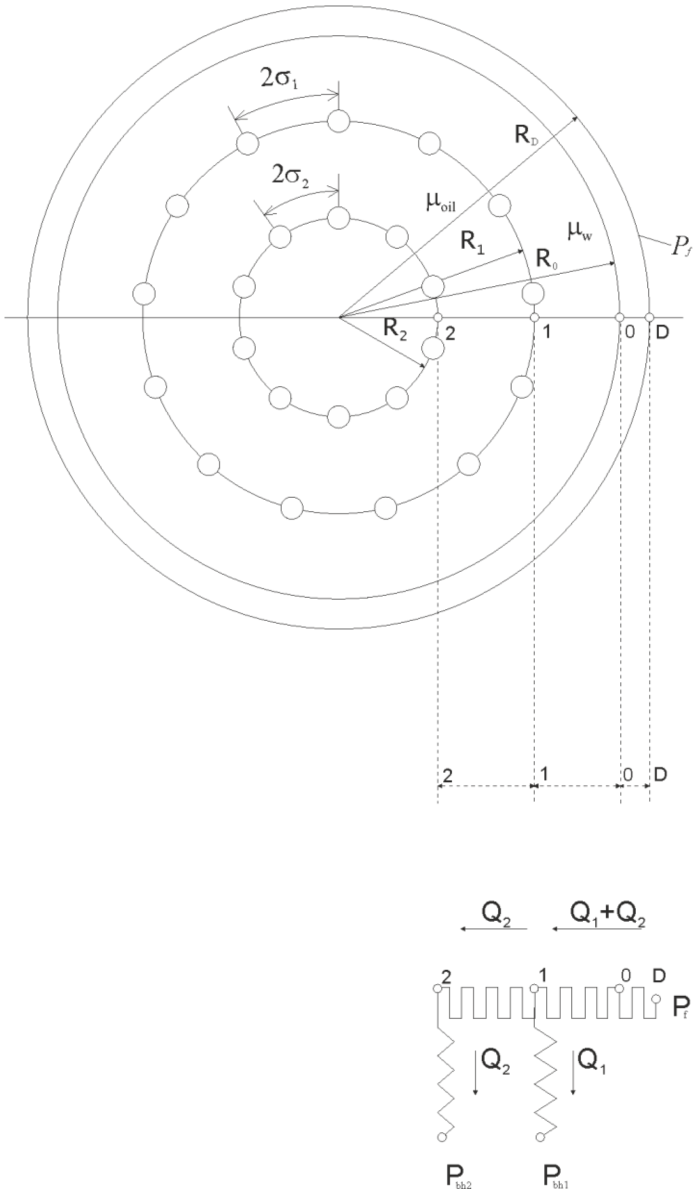


Figure 3.5 - Gydrodynamic and electrical schemes of circle deposit which is developeted by two rows of wells

Using the principle EGDA we write a system of equations

$$\begin{cases} P_f - P_{bh1} = (Q_1 + Q_2)\Omega_{D-0} + (Q_1 + Q_2)\Omega_{0-1} + Q_1\omega_1; \\ P_f - P_{bh2} = (Q_1 + Q_2)\Omega_{D-0} + (Q_1 + Q_2)\Omega_{0-1} + Q_2\Omega_{1-2} + Q_2\omega_2. \end{cases} \qquad (3.12)$$

External filtration resistances for circle deposit are defined by formulas (3.13)-(3.15)

$$\Omega_{D-0} = \frac{\mu_w \ln \frac{R_D}{R_0}}{2\pi kh}; \qquad (3.13) \qquad \Omega_{0-1} = \frac{\mu_{oil} \ln \frac{R_0}{R_1}}{2\pi kh}; \qquad (3.14)$$

$$\Omega_{1-2} = \frac{\mu_{oil} \ln \frac{R_1}{R_2}}{2\pi kh}. \qquad (3.15)$$

where R_D – radius drainage boundary, m; R_0 – radius WOC, m; R_1, R_2 – radiuses first and second rows of wells, m.

Half distance between the wells for circle deposit is defined by the formula

$$\sigma_i = \frac{\pi R_i}{n_i},$$

where n_i - the number of wells in a row.

Solving equation (3.12) determines the bottom-hole pressures of rows of wells.

From system (3.3) determining the flowrate of each row of wells can determine the total flow rate of deposit

$$Q_{sum} = \sum_{i=1}^{n} Q_i$$

and flowrate in a row, assuming they have the same flowrates

$$q_i = Q_i / n_i.$$

If the change number rows of production wells, the system of equation (3.3) differing only in the number of equations. The structure and order of the equations remain the same. Directly from the equation (3.3) a connection between Q and n (Fig. 3.6).

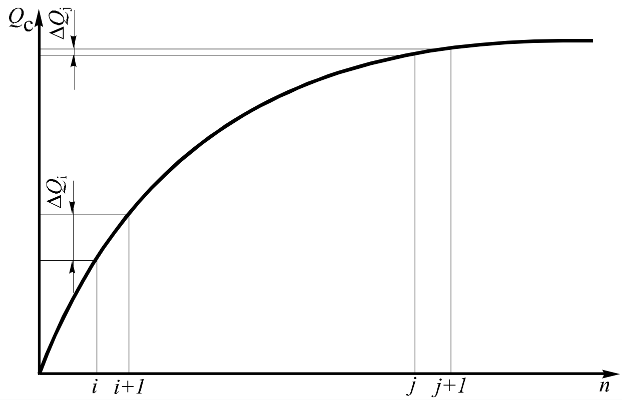


Figure 3.6 - The dependence of oil production from the number of wells

The relationship between the number of wells and the summary liquid production is nonlinear. When the number of wells may come a time when increasing the number of wells does not increase production. Then for increasing oil production need to change the operating conditions of wells that change bottom-hole pressure.

Calculation validities are based on data on the flow rates of wells. Full validity consists of separate validities of displacement calculation WOC from its initial position to the line of the first row of wells, from the line the first row of wells to the line of the second row of wells, and etc.

Time displacement of the oil-bearing path from one position to another is given by the formula

$$t = \frac{Q_{res.}}{\sum\limits_{i=n} Q_i} \frac{1}{1 - \frac{n_w}{100}}, \tag{3.13}$$

where $Q_{res.}$ - recoverable oil reserves in the area of the substitution of oil with water, determined by the Zhdanov’s formula; ΣQ_i - the total flow rate of all wells operating at a given time; n_w – water-cut, %.

Oil reserves in the zone of displacement for strip deposit

$$Q_{res.} = Bhlm\rho_0\eta \,, \tag{3.14}$$

where l - the distance between the WOC, m; ρ_0 - initial oil-saturation; η - oil recovery factor.

Oil reserves in the zone of displacement for circle deposit

$$Q_{res.} = \pi\left(R_1^2 - R_2^2\right)hm\rho_0\eta \,, \tag{3.15}$$

where R_1, R_2 – radiuses WOC in two positions at the beginning and end of the billing period, m.

Calculation of validity of deposit is as follows. Determine the time moving of WOC from the initial position to the first row of wells

$$t_1 = \frac{Q_{res.1}}{\sum\limits_{i=n_1} Q_1} \frac{1}{1 - \frac{n_{w1}}{100}} \,. \tag{3.16}$$

Then determine the time moving of WOC wells from the first row of the second

$$t_2 = \frac{Q_{res.2}}{\sum\limits_{i=n_2} Q_2} \frac{1}{1 - \frac{n_{w2}}{100}} \,. \tag{3.17}$$

The total validity

$$T = \sum_{i=1}^{i=k} t_i \tag{3.18}$$

where k – amount rows of wells.

3.1.4 Consideration two-phase seepage under the water-oil displacement

In all the above tasks of oil displacement water is the scheme of piston displacement. **Piston displacement** - a condition, is taken in the performance of hydrodynamic calculations displacement of oil by water, which states that the residual oil saturation behind the front displacement remains constant. This is the perfect case oil displacement when the layer between oil and water creates a clear border section, which moves ahead of oil and behind only water. And as shown by laboratory and industrial researches front displacement is a compatible flow of water and oil. Filtration resistances in the zone of oil replacement water will differ from the filtration resistances calculated at scheme homogeneous liquid piston displacement. Therefore, it can consider this fact can lead to errors in determining the flow rates and validities.

It is established that the ratio of the viscosity of oil to the viscosity of water $\mu_0=\mu_{oil}/\mu_w$, which ranges from 1 to 10 in the displacement of oil by water can be taken

$$z = \sqrt{\frac{m\mu_0 V}{150 Q(t)}}, \tag{3.19}$$

where $z=\rho_o-\rho_{ro}$; m – coefficient of porosity; V – the volume of the layer; $Q(t)$ - the total amount of water that entered in the reservoir. Equation (19) defines oil saturation at any point depending on its position. Oil saturation at the front oil water displacement is determined by the formula

$$z_f = 0{,}1\sqrt{\frac{\mu_0}{1{,}5(1-\rho_{r\,o}-\rho_{bw})-z_{\phi}}}, \quad \text{f. u.} \tag{3.20}$$

where $\mu_0=\mu_{oil}/\mu_w$; $\rho_{r\,o}$ - residual oil saturation, f.u.; $\rho_{b\,w}$ - saturation of bound water, f.u.

Equation (3.20) is solved the graphic-analytical method. For this first from the equation (3.20) is determined the value $1-\rho_{r\,o} - \rho_{b\,w}$.

To do this, the left and right sides of the equation (3.20) to lift the square. We obtain

$$1-\rho_{r\,o}-\rho_{bw}=\frac{1}{1{,}5}\left(\frac{0{,}01\mu_0}{z_f^2}+z_f\right). \qquad (3.21)$$

Resorting intermediate values z_f and for each value, we get the left side of equation (3.21). For ease of calculation is served at a Table 3.1.

Table 3.1 – Calculation of z_f

z_f	$1-\rho_{r\,o}-\rho_{b\,w}$
0,1	X_1
0,2	X_2
0,3	X_3
……	……
1,0	X_n

Then, the obtained values get the graph. The values $\rho_{r\,o}$ and $\rho_{b\,w}$ are set as defined in the laboratories of the oil and gas mechanics (Fig. 3.7).

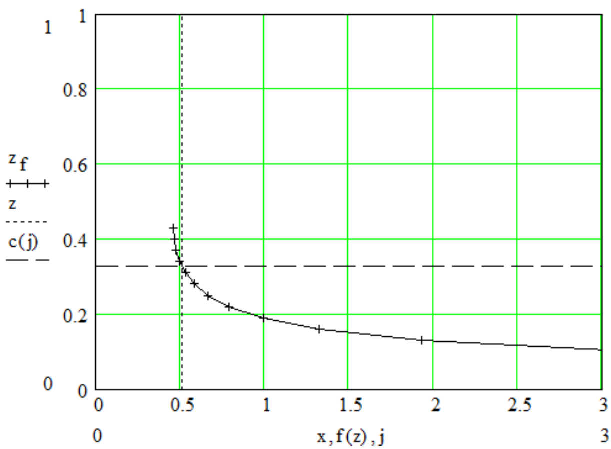


Figure 3.7 - Graph for definition oil saturation at the front water-oil displacement

The value plotted $1\text{-}\rho_{r\ o}$ - $\rho_{b\ w}$ we get on the horizontal axis and extending to the intersection with the graph, we get the desired value z_f .

Prof. Borisov showed that increased filtration resistance in the zone of replacement of oil with water can be considered the introduction of a formula filtration resistance coefficient for this zone to increase filtration resistance.

Coefficient to increase filtration resistance α shows in how many times the increased resistance in the zone of replacement of oil with water. For strip, the deposit is determined by the formula

$$\alpha = \frac{\mu_w}{\mu_{oil}}\left(1{,}7 + 8z_f + 25z_f^2\right), \qquad (3.22)$$

where z_f - oil saturation at the front water-oil displacement.

For circle deposit we have two cases:

1) the displacement of oil by water from the periphery to the centre

$$\alpha_1 = \frac{\mu_w}{\mu_{oil}}\left[1{,}7 + 8z_f\varphi_1\left(\frac{r_f}{R_0}\right) + 25z_f^2\varphi_2\left(\frac{r_f}{R_0}\right)\right];$$

2) the displacement of oil by water from the centre to the periphery

$$\alpha_2 = \frac{\mu_w}{\mu_{oil}}\left[1{,}7 + 8z_f\varphi_1'\left(\frac{R_0}{r_f}\right) + 25z_f^2\varphi_2'\left(\frac{R_0}{r_f}\right)\right].$$

where φ_1, φ_2, φ_1', φ_2' - auxiliary functions that are dependencies on graphs (Fig. 3.8); R_0 - the radius of the initial position WOC, m; R_f - radius of the intermediate position WOC, m.

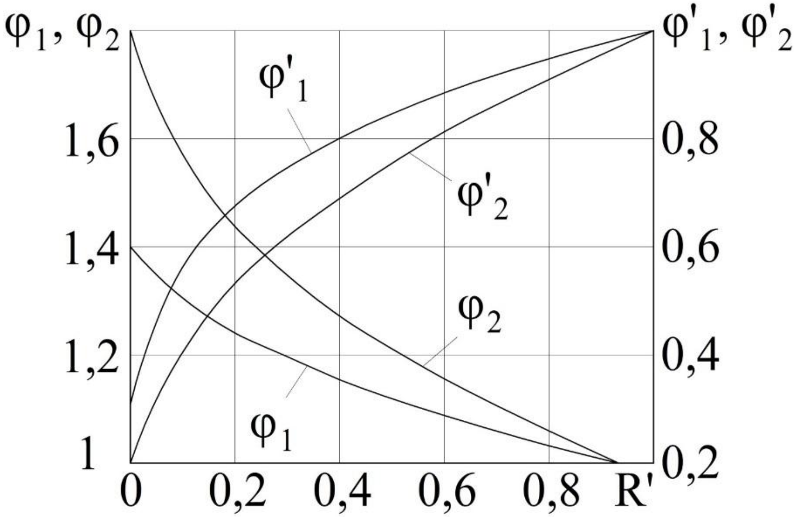


Figure 3.8 – Graphs for the definition of functions φ_1 and φ_2

Example 3. We have strip deposit, which is being developed by two rows of wells with the moving WOC. We knew: reservoir parameters and reservoir fluids and number of wells (Fig. 3.9).

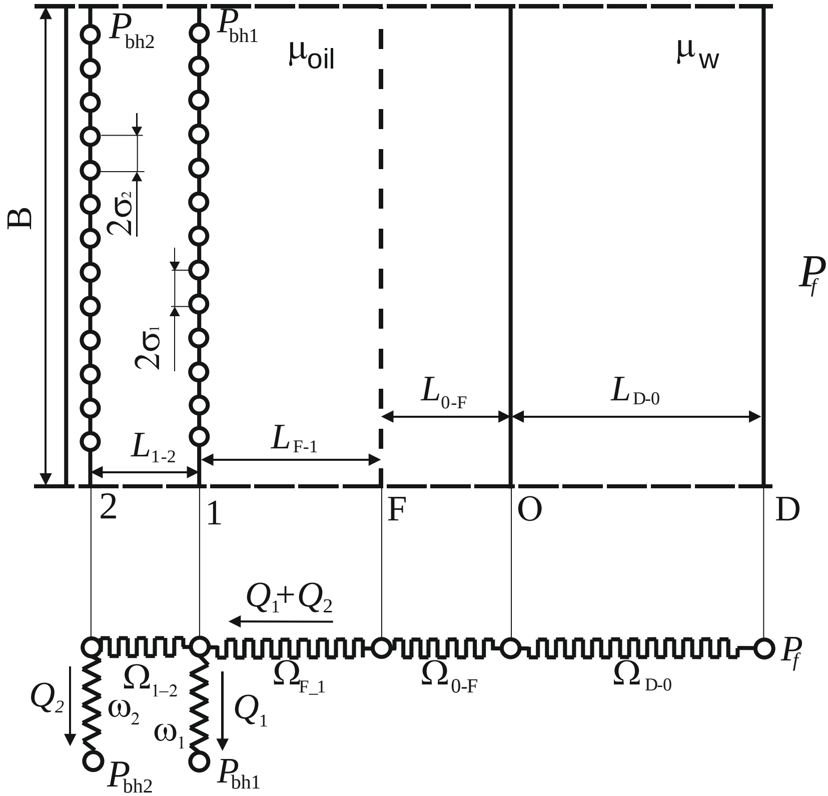


Figure 3.9 - Gydrodynamic and electrical scheme of strip deposit which is developeted by two rows of wells with moving WOC

At the region of the layer between the initial position, WOC and the first row of wells emit a series intermediate positions of WOC. Up to the electrical scheme of process. If you compare this to the electrical scheme mentioned earlier, we can see that there is one additional branch electrical of the scheme, or rather for region 0-1 break regions 0-F and F-1. Record of the equation for series of intermediate positions WOC. Solving the system of equations determined instantaneous (momentary) flowrate at given bottom-hole pressure in wells or pressure bottom-hole at the given flow rate. For when thou method, a system of equations (we have two equations), when the WOC is written at point F

$$\begin{cases} P_f - P_{bh1} = (Q_1 + Q_2)\Omega_{D-0} + (Q_1 + Q_2)\Omega_{0-F}\alpha + (Q_1 + Q_2)\Omega_{F-1} + Q_1\omega_1; \\ P_f - P_{bh2} = (Q_1 + Q_2)\Omega_{D-0} + (Q_1 + Q_2)\Omega_{0-F}\alpha + (Q_1 + Q_2)\Omega_{F-1} + \\ \qquad + Q_2\Omega_{1-2} + Q_2\omega_2, \end{cases}$$

where α - *c*oefficient to increase filtration resistance. It is defined by the formula (3.22).

External filtration resistance for region 0-F is defined by the formula (at the region O-F at the formula we substitute the coefficient of dynamic viscosity oil)

$$\Omega_{0-F} = \frac{\mu_{oil} l_{0-F}}{Bkh}.$$

If the task is solved for the case when $Q = const$, then the equation (3.22) wondering intermediate position WOC ($l_{0\text{-}F}$) determine the bottom-hole pressure depending on the position of the WOC.

If the task is solved for the case when $P_{bh} = const$, the same way the series is calculated the flow rate of wells depending on the position of the WOC.

Dynamic basic indicators of development depending on the time under water drive are shown in Fig. 3.10.

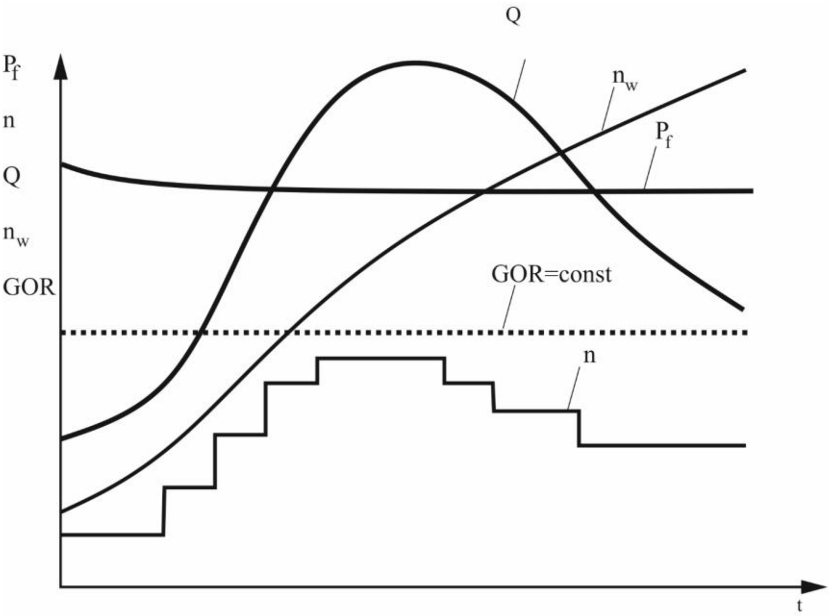


Figure 3.10 - Dynamic basic indicators of development under water drive

Under water drive, oil production accompanied by its replacement water, which explains the stable value over time flowrates of wells, formation pressure and gas oil ratio.

§3.2 MAIN HYDRODYNAMIC CALCULATIONS UNDER ELASTIC-WATER DRIVE

Condition of elastic-water drive - excess formation pressure above the saturation pressure. The drive appears in early development and is characterized in descending reservoir pressure. In solving elastic-water drive the important task is to develop a definition of conversion put the solution gas drive. Knowledge of the time of development is necessary to determine the time that is given to the resettlement area of the building maintain formation pressure.

Condition of elastic fluid and reservoir porosity depending on the pressure described by the following equations

$$\rho = \rho_0 \left[1 + \beta_{fl}\left(P - P_0\right)\right], \qquad (3.23)$$

$$m = m_0 + \beta_r (P - P_0), \qquad (3.24)$$

where m_0, ρ_0 - porosity and density under initial pressure; β_{fl} - compressibility factor of the fluid, 1/Pa; β_r - compressibility factor of the porous medium, 1/Pa. These factors are determined in the laboratory.

From the reservoir when the pressure is reduced due to the elastic expansion of the fluid and rocks will be released a volume of fluid

$$\Delta V_{fl} = \beta_{fl} V_p \Delta P + \beta_r V_0 \Delta P, \qquad (3.25)$$

but $V_p = mV_0$ and substituting in the equation (3.25)

$$\Delta V_{fl} = \beta_{fl}\, mV_0\, \Delta P + \beta_r V_0 \Delta P = (m\beta_{fl} + \beta_r) V_0\, \Delta P.$$

We introduce the notation

$$\beta_{fl}\, m + \beta_r = \beta^*,$$

β^* - an elastic capacity factor of the reservoir rock, 1/Pa. It shows the change in the stock of elastic fluid per unit volume when the pressure of 1 MPa.

Elastic reserve reservoir

$$\Delta V_{fl} = \beta^* V_0 \Delta P, \qquad (3.26)$$

where V_0 - reservoir volume, m^3; ΔP - change in pressure, Pa.

The disadvantage of the formula (3.26) is that it is not related to time. Therefore advisable to determine the indicators of development will be the formula

$$P(r,t) = P_f - \frac{Q\mu}{4\pi kh}\left[E_i\left(-\frac{r^2}{4\chi \cdot t}\right)\right],$$

or

$$P(r,t) = P_f - \frac{Q\mu}{4\pi kh}\int_{u^2}^{\infty}\frac{e^{-u}}{u}du,$$

where $u = \dfrac{r}{2\sqrt{\chi t}}$, E_i - exponential function.

After mathematical transformations, we obtain the basic formula of elastic drive

$$P(r,t) = P_f - \frac{Q\mu}{4\pi kh}\ln\frac{2{,}25\chi t}{r^2}, \tag{3.27}$$

where $P(r, t)$ - pressure at a distance r in time t, Pa; P_f – formation pressure, Pa; Q – performance (or flowrate), m^3/s; μ – dynamic viscosity of the fluid, Pa·s; k – permeability coefficient of the reservoir rock, m^2; h – layer thickness, m; χ – piezoconductivity factor, m^2/s.

Piezoconductivity factor characterises the rate of transmission of pressure in the formation and determines by the formula

$$\chi = \frac{k}{\mu\beta *}, \tag{3.27}$$

it varies from 0.1 to 5.0 m^2/s.

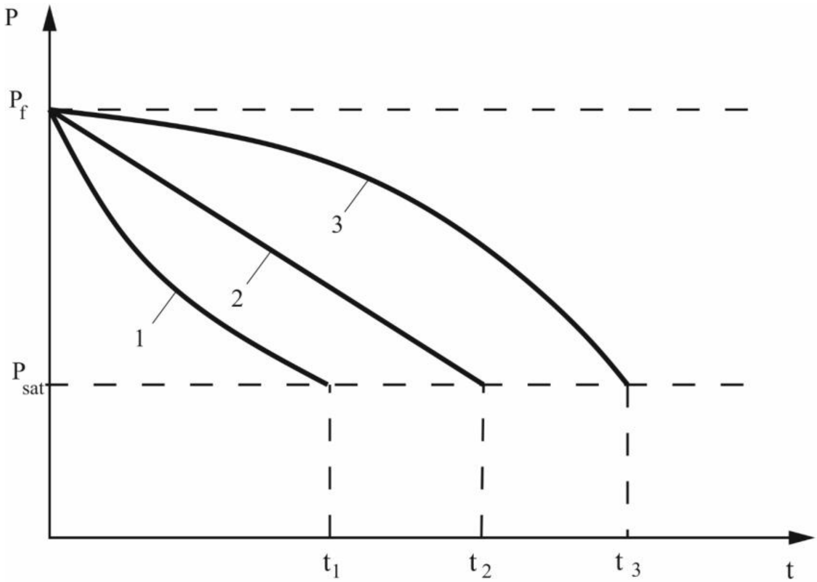
Bottom-hole pressure is determined by the formula

$$P(r_w,t) = P_f - \frac{Q\mu}{4\pi kh}\ln\frac{2{,}25\chi t}{r_{rw}{}^2}, \tag{3.28}$$

where r_{wr} – reduce radius, m. Reduce radius - is a radius, which should be well, so that it was perfect.

Formula (3.27) in the oilfield practices used to assess pressure changes over time, depending on the selection in the initial stage of development of oil when the deposit on a small number of wells. It is assumed that the selection is centred in the heart lay, and the change in pressure is determined by the distance from the centre.

Figure 3.11 shows the change in pressure over time, performed for different values of Q, which are set constant. Graphic dependences shown in figure 1 can be concluded that the selection of fluid must agree with the period of time development and completion of construction of reservoir pressure maintenance. Unregulated in terms of selection of liquid elastic-water drive can result, which will take place in the deposit solution gas drive. The higher the Q wonder, the faster the pressure reaches the saturation pressure.



If $Q_1 > Q_2 > Q_3$, when $Q_1t_1 < Q_2t_2 < Q_3t_3$ (where $Q{\cdot}t$ – accumulated oil production)

Figure 3.11 - Change formation pressure at the time of selection for different values of Q_1, Q_2, Q_3

As a result of the trial, operation is put actual pressure change over time. Often it does not coincide with the theoretical, the projected change in pressure over time. The difference may be due to an error of the mean values of parameters taken reservoir, installed within the studied tend oil-bearing part of the reservoir and the water shortage area or put isolation, the presence of the active zone of water flow. Theoretical calculations performed depending on the basic formula of the elastic drive. For the coordination of theoretical and actual dependencies in formula (3.27) is introduced coefficients z_1 and z_2 for harmonization of the parameters of layer and formation fluid (adaptive coefficients). So, we have

$$P(r,t) = P_f - \frac{Q\mu}{4\pi kh} z_1 \left[E_i \left(-\frac{r^2}{4\chi \cdot t} \cdot z_2 \right) \right], \tag{3.29}$$

де $z_1 = \dfrac{\left(\dfrac{kh}{\mu}\right)_{theor}}{\left(\dfrac{kh}{\mu}\right)_{act}}$; $\quad z_2 = \dfrac{\chi_{theor}}{\chi_{act}}$.

To find the unknown coefficients z_1 and z_2 rewrite equation (3.29) at time t_1 and t_2

$$\begin{cases} P(r,t_1) = P_f - \dfrac{Q\mu}{4\pi kh} z_1 \left[E_i \left(-\dfrac{r^2}{4\chi \cdot t_1} \cdot z_2 \right) \right], \\ P(r,t_2) = P_f - \dfrac{Q\mu}{4\pi kh} z_1 \left[E_i \left(-\dfrac{r^2}{4\chi \cdot t_2} \cdot z_2 \right) \right]. \end{cases} \tag{3.30}$$

In general, the task of determining the change in pressure is solved for two cases:

1) *Q (t) = const*;

2) *Q (t) ≠ const*.

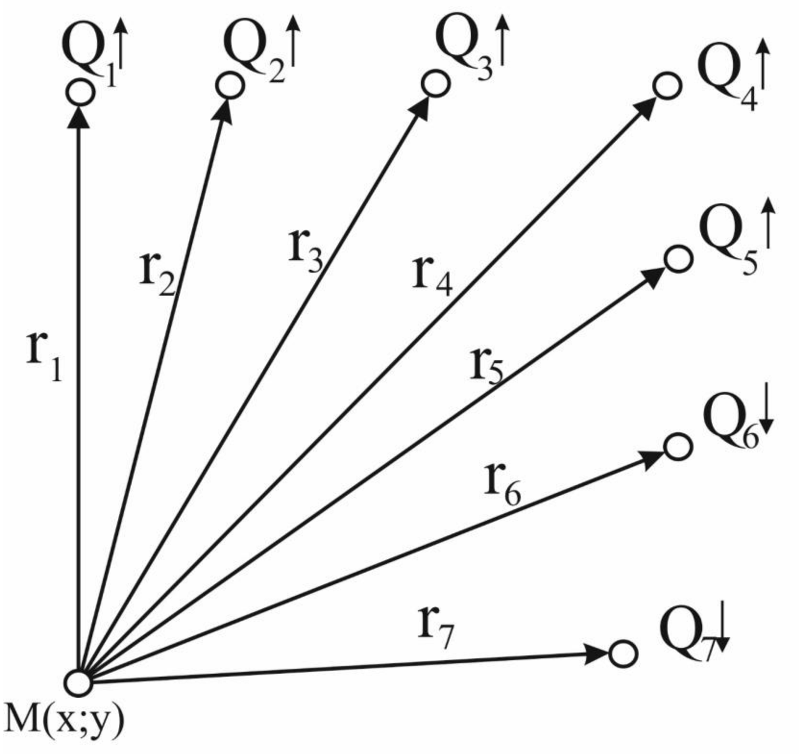
If the task is solved for *Q (t) = const*, then use the basic formula of elastic drive

$$\Delta P = \frac{Q\mu}{4\pi kh} \ln \frac{2{,}25\chi t}{r^2} .$$

If the task is solved for $Q(t) \neq const$, then use the **method of superposition.**

The method of superposition - a way of solving hydrodynamic tasks when their general solution defined as the sum of the solutions. In other words, changing the pressure at any point of the layer is determined by the direct summation of depression caused by the work of single wells.

In the event that the deposit on working well with different flowrates (Q), and the need to find a change of pressure in any point of the layer (p. M), then come true (Fig. 3.12).



↑ - production well; ↓ - injection well.

Figure 3.12 - The method of superposition

The task is solved using the method of superposition

$$\Delta P_M(t) = \frac{Q_1\mu}{4\pi kh}\ln\frac{2{,}25\chi t_1}{r_1^{\ 2}} + \frac{Q_2\mu}{4\pi kh}\ln\frac{2{,}25\chi t_2}{r_2^{\ 2}} + \ldots + \frac{Q_5\mu}{4\pi kh}\ln\frac{2{,}25\chi t_5}{r_5^{\ 2}} -$$

$$-\frac{Q_6\mu_w}{4\pi kh}\ln\frac{2{,}25\chi t_6}{r_6^{\ 2}} - \frac{Q_7\mu_w}{4\pi kh}\ln\frac{2{,}25\chi t_7}{r_7^{\ 2}}. \qquad (3.31)$$

By changing the position of the M put on the area and each time hoping the pressure $\Delta P(t)$, can be traced to changes in pressure put on the area.

Then placing wells more convenient to set coordinates (x_1, y_1), (x_2, y_2), (x_3, y_3), etc., and the position of point M coordinates (x, y). Then the distance from the point M to be written using the coordinates of wells

$$r_1^2 = (x - x_1)^2 + (y - y_1)^2; \quad r_2^2 = (x - x_2)^2 + (y - y_2)^2.$$

Dynamic basic indicators of development depending on the time under elastic drive are shown in Fig. 3.13.

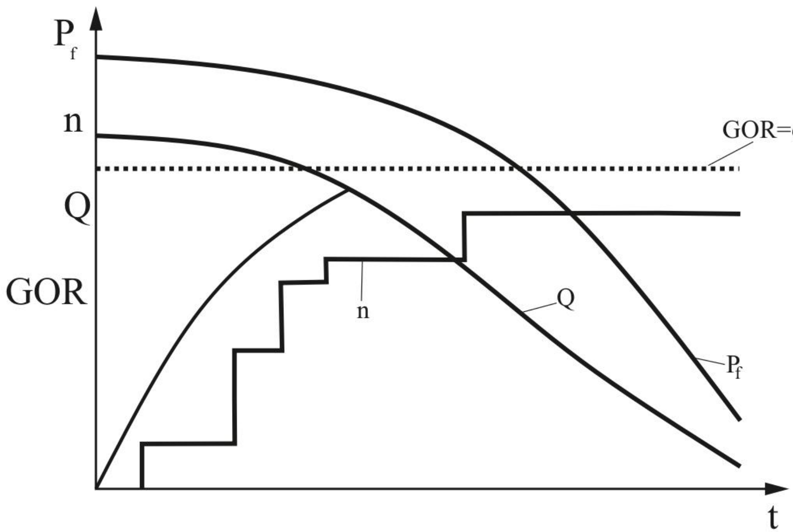


Figure 3.13 - Dynamic basic indicators of development under elastic-water drive

Thus, analytical calculations of oil put options in respect to elastic drive based on the use of the basic formula elastic drive and method of superposition. They are appropriate for surgical use, approximate prediction indicators of development.

§3.3 MAIN HYDRODYNAMIC CALCULATIONS UNDER SOLUTION GAS DRIVE

Solution gas drive is manifested in the oil reservoir when the main force that moves the oil layer on to the bottom-hole is the energy of the gas dissolved in oil.

Exploitation under the solution gas drive characterized by a low coefficient oil recovery. Therefore, this drive will develop are small-screened deposits, where creating a system maintaining reservoir pressure economically appropriate or impossible.

The hydrodynamic theory of oil deposits under the solution gas drive today is approximate and is based on assumptions:

1. The movement of oil and gas have taken flat in the absence of the field of gravitational forces.

2. Consider the horizontal layer, which dissolved gas reserves are taken evenly distributed and there is no possibility of accumulation of the gas cap.

3. Not captured surface forces between gas bubbles and oil.

4. Accepted thermodynamic equilibrium in the system “dissolved gas-oil”.

Analytical solutions are approximately listed in solder even assumptions.

Field of the existence of this drive lies below the saturation pressure. Difficulty hydrodynamic calculations under the solution gas drive are that while reducing the pressure below the saturation pressure of the oil released gas. And accordingly, the porous medium is a two-phase filtration flow.

3.3.1 Definition of oil saturation at the end of the interval pressure changes

Determination development indicators under the solution gas drive is a difficult task because the drive is characterized in descending time formation pressure and change properties reservoir oil. To calculate development indicators (flowrates, pressures, gas-oil ratio, oil recovery factor, time development) must first determine the relationship between oil saturation and pressure.

This dependence is expressed by an approximate formula which was obtained Zinovyeva. By the method, Zinovyeva calculations are performed in that order. Record oil saturation formula for determining the end of interval pressure changes

$$\rho_{k\,i+1} = \frac{\dfrac{\overline{G} - S(P_{k\,i})}{b(P_{k\,i})}\rho_{k\,i} - (1-\rho_{k\,i})\dfrac{P_{k\,i}}{z(P_{k\,i})} + \dfrac{P_{k\,i+1}}{z(P_{k\,i+1})}}{\dfrac{\overline{G} - S(P_{k\,i+1})}{b(P_{k\,i+1})} + \dfrac{P_{k\,i+1}}{z(P_{k\,i+1})}}, \qquad (3.32)$$

where $\overline{G}$ - average gas-oil ratio (GOR) at the interval of change of pressure from P_{ki} to $P_{k\,i+1}$ (P_{ki} - pressure at the beginning of the interval pressure changes; $P_{k\,i+1}$ - the pressure at the end of the interval changes in pressure, and $P_{k\,i} > P_{k\,i+1}$); $S(P_{ki})$, $S(P_{k\,i+1})$ - the amount of gas that is dissolved in the oil under pressures P_{ki} and $P_{k\,i+1}$, m^3/m^3; $b(P_{k\,i})$, $b(P_{k\,i+1})$ – volume formation factor at the appropriate pressures; $\rho_{k\,I}$ - initial oil saturation; $z(P_{k\,i})$, $z(P_{k\,i+1})$ – gas compressibility factor under the appropriate pressures.

The average gas-oil ratio at the interval of change of pressure is given by the formula

$$\overline{G} = \psi\left(\rho_{k\,i}\right)\frac{\overline{P}}{z(\overline{P})}\frac{\mu_{oil}\left(\overline{P}\right)}{\mu_{gas}\left(\overline{P}\right)}b\left(\overline{P}\right) + S\left(\overline{P}\right), \qquad (3.33)$$

where $\overline{P} = \dfrac{P_{k\,i} + P_{k\,i+1}}{2}$ - average pressure; $\psi(\rho_{k\ i})$ - Tsarevich function, represents the ratio from relative permeability to gas (F_{gas}) to the relative permeability to oil (F_{oil})

$\psi\left(\rho_{k\,i}\right) = \dfrac{F_{gas}}{F_{oil}}$ (depending on the relative permeability at the table oil saturation).

The values of all parameters included in the formula (3.33) must substitute the average pressure. The pressure in the formula (3.32) and (3.33) must be a substitute in MPa.

Dependences reservoir properties of oil and gas from the saturation pressure are shown in Fig. 3.14.

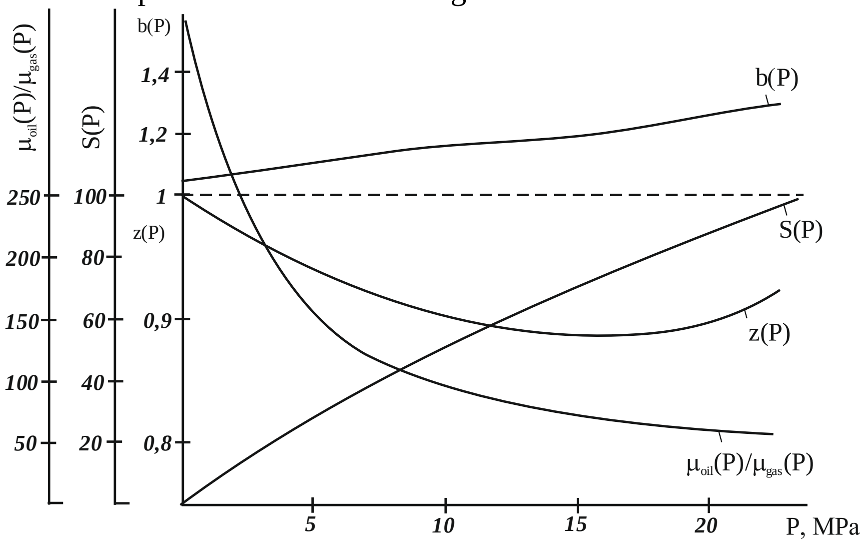


Fig. 3.14 - Dependences of the properties of reservoir oil and gas from saturation pressure

The procedure is the following calculations.

The whole interval of possible changes in the value of formation pressure is divided into small spaces. To ensure high accuracy of set pressure interval and $P_{k\ i}$ and $P_{k\ i+1}$ equal to 0.1-0.2 MPa. Practice shows that the smaller the interval between the commitments and values $P_{k\ i}$ and $P_{k\ i+1}$, the more precisely determined depending $\rho(P)$. In some cases, the amount of pressure $P_{k\ i}$ -$P_{k\ i+1}$ and can be increased and make 0.5-1.0 MPa. Then, set the initial value for the first interval oil saturation calculation (it is 1). From tables, Tsarevich determines Tsarevich function $\psi(\rho_{k\ i})$ and for the graphics dependency of oil and gas properties define the parameters S, b, z, under appropriate pressures.

Table Tsarevich are as follows:

ρ	$F_{oil}(\rho)$	$F_{gas}(\rho)$
1	0	1

Then determine the gas-oil factor formula (3.33) and the formula (3/32) determine oil saturation at the end of the selected interval pressure changes. Then move to the next interval changes in pressure, where the initial oil saturation serving predefined value.

As a result of these calculations get graphic dependence (Fig. 3.15).

3.3.2 Definition of flowrates, bottom-hole pressures under solution gas drive

The task is solved for two cases:

1) $Q(t)$=const;

2) $P_{вh}$= const.

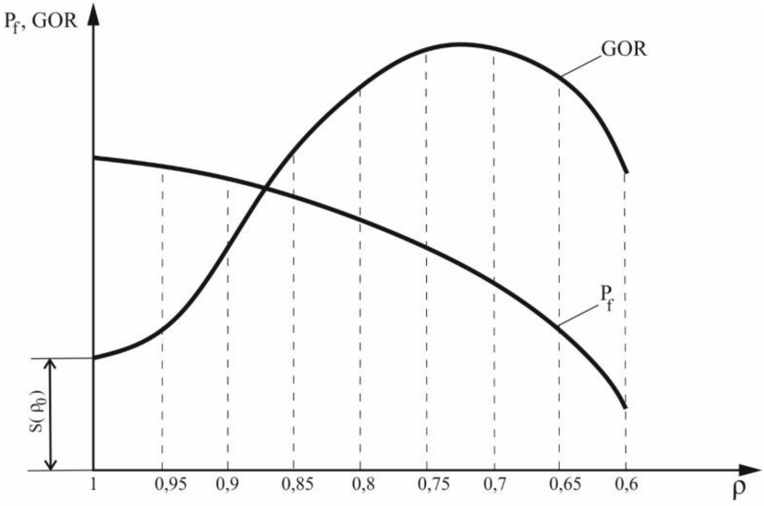


Fig. 3.15 – Dependence of average formation pressure and gas-oil ratio (GOR) from oil saturation

Condition $Q(t)$ = const possible only for the initial stage of development of the field when the formation pressure is high and the condition of constant flow rate at the fountain and the mechanized methods, as in these conditions although a decrease in the formation and bottom-hole pressures, their value is still high and selection can be made adjustable oil.

At the later stage of development, when the formation and bottom-hole pressures do not provide flowing wells, and power mechanized method (increase immersion tubing or pump) is fully used, the condition of constancy exercise selection is not possible. Then justified wells in operation is $P_{вh}$ = const.

Equation flow of oil from the reservoir into the well has the form

$$Q = \frac{2\pi k h\left(H_f - H_{bh}\right)}{\ln \frac{R_d}{r_{rw}}}, \tag{3.34}$$

where $H_f - H_{bh}$ - Khristianovich difference functions; $r_{r\,w}$ - reduce the radius of well.

Khristianovich difference functions determined by the formula

$$H_f - H_{bh} = \int_{P_{bh}}^{P_f} \frac{F_{oil}(\rho)}{\mu_{oil}(P)\beta(P)} dP \,. \tag{3.35}$$

$$\text{Or}\, Q = \frac{2\pi kh \cdot A\left(P_f - P_{bh}\right)}{\mu \ln \frac{R_d}{r_{r\,w}}}, \tag{3.36}$$

rewriting the formula (3.36), we obtain

$$Q = \frac{2\pi kh\left(P_f - P_{bh}\right)}{\frac{\mu}{A} \ln \frac{R_d}{r_{r\,w}}},$$

where $\mu_f = \frac{\mu}{A}$ - a fictional viscosity.

Using formulas (3.34) and (3.36), we get

$\frac{1}{A} = \frac{P_f - P_{bh}}{H_f - H_{bh}}$ - coefficient to increase filtration resistance due to the two-phase filtration flow.

Hlohovskyy, Rosenberg got the formula for determining the coefficient A

$A=0{,}944\text{-}21{,}43\alpha$,

where $\alpha = \alpha_p \frac{\mu_{gas}}{\mu_{oil}}$, α_p – solubility factor of gas in the oil.

Based on the formula (3.35) for more oil Zinovyeva was showed the possibility of approximation of the equation straight line

$$\frac{F_{oil}(\rho)}{\mu_{oil}(P)b(P)} = aP + b\,, \tag{3.37}$$

where a and b - approximation coefficients that are constant for a given oil and gas at a certain pressure.

There are two methods for determining coefficients a and b:

1) dependencies on graphics;
2) analytically.

To do this, we write the equation (6) for two values of P_{ki} and $P_{k\,i+1}$

$$\begin{cases} \dfrac{F_{oil}\left(\rho_{k\,i}\right)}{\mu_{oil}\left(P_{k\,i}\right)b\left(P_{k\,i}\right)} = aP_{k\,i} + b; \\ \dfrac{F_{oil}\left(\rho_{k\,i+1}\right)}{\mu_{oil}\left(P_{k\,i+1}\right)b\left(P_{k\,i+1}\right)} = aP_{k\,i+1} + b. \end{cases} \tag{3.38}$$

Solving system of equations (3.38) determine the coefficients a and b. For this equation deducted from the first second. We have

$$a = \frac{\dfrac{F_{oil}\left(\rho_{k\,i}\right)}{\mu_{oil}\left(P_{k\,i}\right)b\left(P_{k\,i}\right)} - \dfrac{F_{oil}\left(\rho_{k\,i+1}\right)}{\mu_{oil}\left(P_{k\,i+1}\right)b\left(P_{k\,i+1}\right)}}{P_{k\,i} - P_{k\,i+1}}\ .$$

From the first equation defines the coefficient b

$$b = \frac{F_{oil}\left(\rho_{k\,i}\right)}{\mu_{oil}\left(P_{k\,i}\right)b\left(P_{k\,i}\right)} - aP_{k\,i}\text{, or}$$

$$b = \frac{F_{oil}\left(\rho_{k\,i}\right)}{\mu_{oil}\left(P_{k\,i}\right)b\left(P_{k\,i}\right)} - \frac{\dfrac{F_{oil}\left(\rho_{k\,i}\right)}{\mu_{oil}\left(P_{k\,i}\right)b\left(P_{k\,i}\right)} - \dfrac{F_{oil}\left(\rho_{k\,i+1}\right)}{\mu_{oil}\left(P_{k\,i+1}\right)b\left(P_{k\,i+1}\right)}}{P_{k\,i} - P_{k\,i+1}} P_{k\,i}\,.$$

There is another oil inflow equation

$$Q = \frac{2\pi k h \left(P_f - P_{bh}\right)\varphi}{\ln \frac{R_d}{r_{rw}}}, \tag{3.39}$$

where $\varphi = \left| \frac{F_{oil}(\rho)}{\mu_{oil}\left(\overline{P}\right) b\left(\overline{P}\right)} \right|_{\overline{P} = \frac{P_f + P_{bh}}{2}}$. (3.40)

Substituting (3.37) to (3.35) and following the integration, we get

$$H_f - H_{bh} = \frac{a}{2}\left(P_f{}^2 - P_{bh}{}^2\right) + b\left(P_f - P_{bh}\right). \tag{3.41}$$

Solving equation (3.41) for the expression of the bottom-hole pressure

$$P_{bh} = P_f + \frac{b}{a} - \sqrt{\left(\frac{b}{a}\right)^2 + \frac{2\left(H_f - H_{bh}\right)}{a}}. \tag{3.42}$$

The proposed methodology for determining the flowrates at the set bottom hole pressures and determination of bottom hole pressures at the set flowrates.

3.3.2 Definition of validities under solution gas drive

Validities for condition $Q(t)$ = const determined by the formula

$$t_{Q=const} = \frac{\Omega}{Q}\left[\frac{\rho_0}{b\left(P_0\right)} - \frac{\rho_k}{b\left(P_k\right)}\right], \tag{3.43}$$

where Ω - pore volume per one well and determined by the formula

$$\Omega = \pi R_d{}^2 hm. \tag{3.44}$$

If the task solve for condition P_{bh} = const, then formulas (3.34), (3.36) changes for each interval pressure calculated average flowrate

$$\overline{Q} = \frac{Q_{k\,i} + Q_{k\,i+1}}{2} \quad .$$

$$\Delta t_{P_{bh}=const} = \frac{\Omega}{\overline{\overline{Q}}}\left[\frac{\rho_{k\,i}}{b(P_{k\,i})} - \frac{\rho_{k\,i+1}}{b(P_{k\,i+1})}\right]. \qquad (3.45)$$

The total validity determined by summing validities for intervals pressure changes

$$T_{P_{bh}=const} = \sum \Delta t_{P_{bh}=const} \; .$$

3.3.4 Placement of wells and oil recovery under solution gas drive

Under solution gas drive formation energy is evenly distributed around the oil areas and depends only on the amount of gas dissolved in a unit volume of oil. Placement of wells in the deposit must obey the following two conditions:

1) if the permeability of the layer area will put about the same, it is well placed for uniform grids;

2) the permeability of the layer area will put uneven, there is an increase in the consolidation grid of wells in the side of the layer permeability worse.

At the same formation parameters of the reservoir, as noted above, it is advisable to place production wells on the uniform grid, unless solution gas drive will be replaced by some other drive. Wells in this case placed on a square or triangular grids and formation divided into the same form of exclusion. Dimensions of form depending on the distance between the wells.

If the distance between the wells mark 2σ, then the square grid equivalent circle radius is

$$R_{k\,\Pi} = \frac{2\sigma}{\sqrt{\pi}} \approx 1{,}13\sigma$$

and triangular grid

$$R_{k\,\Delta} = \frac{2\sigma\sqrt[4]{3}}{\sqrt{2\pi}} \approx 1{,}05\sigma\,.$$

Thus, hydrodynamic calculations are made only for one well and the results apply to all wells.

Hydrodynamic calculations for solution gas drive more difficult and less accurate than in the case of homogeneous oil through that phase permeability are not defined sufficiently precisely and calculations due to the difficulty of differential equations of motion based on approximate methods.

Oil recovery factor under the solution gas drive is calculated using the pressure dependency of oil saturation

$$\eta = 1 - \frac{\rho_{k\,i}}{\rho_0}\,\frac{b(P_0)}{b(P_{k\,i})}, \qquad (3.46)$$

where ρ_0 and $b(P_0)$ – initial oil saturation and volume formation factor under saturation pressure; $\rho_{k\,i}$ and $b(P_{k\,i})$ - oil saturation and volume formation factor under average pressure.

Final oil recovery factor depends on the properties of the formation of oil and gas, from the amount of gas dissolved in oil, and also the phase permeability. However, in all cases, the final oil recovery factor under solution gas drive is lower than the water drive.

Solution gas drive characterized by a rapid drop in the formation pressure over time and increase the gas-oil ratio which at some stage of development reaches a maximum and then begins to decrease as a result of exhaustion and complete decontamination of field. Without action on the artificial reservoir, the drive is ineffective. However, in the initial period of development wells flowing, though not a long time. No water in production wells.

For solution gas drive of development dynamics of development depending on the time is shown in Fig. 3.16.

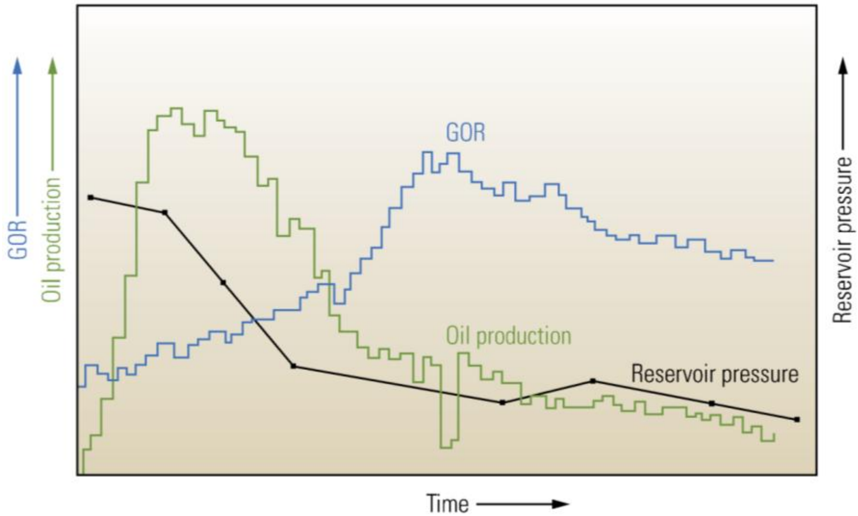


Figure 3.16 - Typical performance from a solution gas drive system. At the initial production with a solution-drive mechanism, the well produces oil (green) with a low gas/oil ratio (GOR) (blue). As oil is extracted, the reservoir pressure (black) drops, gas comes out of solution, and the GOR rises sharply; consequently, oil production drops.

§4 MAINTENANCE OF RESERVOIR PRESSURE BY INJECTION INTO DEPOSIT OF WATER AND GAS

Everybody knows that the natural formation energy does not always ensure complete recovery of the oil or the required production rate. Maintenance of reservoir pressure for injecting water or gas into the reservoir use to achieve higher recovery factors and the necessary rate of oil production is very popular.

§4.1 MAINTENANCE OF RESERVOIR PRESSURE BY WATER INJECTION

The oil recovery rate, the rate of withdrawal of its reserves, is determined by its specific productivity index and by the reserves. The specific productivity index is determined by size and shape of reservoir, physical properties of rocks and fluids, number of wells and their completion, external boundary and bottom-hole pressures and distance from bottom holes to external reservoir boundary. The number of wells and their arrangement as well as bottom-hole pressure is generally controlled by the field personnel; other factors are natural and uncontrollable.

When the loop pressure isn`t high and external reservoir boundary is out of distance, assuming an optimum well spacing and maintaining optimum bottom-hole pressure, a low withdrawal rate can be maintained sometimes.

When applying marginal flooding external boundary can be displaced up to the reservoir and sufficiently high pressure is maintained in it.

Cap is the drainage area as it were and the gas-oil contact may be taken as the drainage boundary in gas-cap reservoirs. Injection of gas into the gas cap helps to maintain the pressure in it and therefore it maintains a steady rate of production or increases it.

Injection of a working fluid into the reservoir not only intensifies production and ensures the maximum oil recovery factor but also increases reservoir pressure and the bottom-hole pressure in the producing wells, prolonging thus the following life of the reservoir.

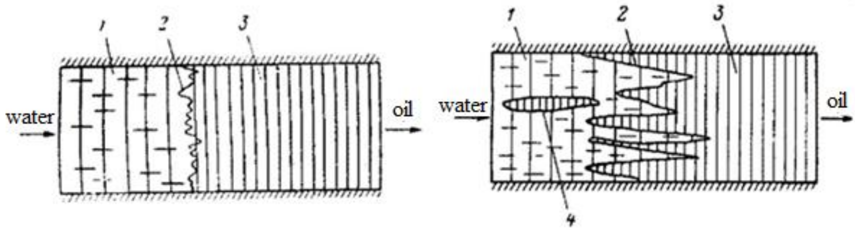
The oil recovery factor depends on shape and size of the reservoir, and also on a number of other factors. Other things being equal, the output of a reservoir depends on the length of the rows of producing wells, i.e., on the length of the oil drainage boundary, and the productive life depends on the reserves, which are approximately proportional to the area and thickness of the deposit. Thus, oil recovery factor is determined on a considerable extent of length of drainage boundary to area of deposit. This ratio may be such that the productive life of the reservoir is unduly prolonged in view of the conversation of the central part of the reservoir. The productive life can be shortened by more intensive exploitation and to achieve this, edge flooding can be supplemented by pattern flooding. The reservoir is divided up into a number of separate fields with using of rows of injection wells, thereby considerably lengthening the drainage boundary and, therefore, also the outer rows of producing wells. Rows of producing wells must be provided on either side of the row of injection wells used in pattern flooding. The recommended procedure is to have not more than 5-7 producing rows between the rows of injection wells. In this way the entire reservoir can be brought into production, the current rate of oil production increases and productive life becomes shorter.

Conditions that favour for the application of pattern flooding present of water underlying the lowermost sections of the formation and continuity of the formation which helps to accelerate effect of injection wells.

The productive life of steep formations can be reduced by injecting gas (or air) near crest of reservoir to create an artificial gas cap, which also increases total length of drainage boundary and length of the outer rows of producing wells.

In practice, the method selected to maintain reservoir pressure depends on geological conditions and economic considerations.

Laboratory experimental researches of oil displacement by water hold in the models of the reservoir and the shown at Fig. 4.1.



1- zone, where is occupied water and residual oil; 2 – WOC; 3 – zone, that is occupied by oil; 4 - accumulations of oil remaining behind WOC

Fig. 4.1 – Scheme of movement WOC in layer under: *a*) $\mu_0 = 1 \div 5$; *b*) $\mu_0 = 20 \div 30$

Development system what is carrying out by pumping water into the reservoir helps to:

a) increase oil production and accelerate the process of development of the field;

b) preservation of stable oil-dominated than the fountain method of operation of oil wells for a long period;

c) increase of the final oil recovery factor for a cost effective generic term of its development;

d) reduction of capital expenditures;

e) increase productivity;

f) reduce the cost of oil.

Waterflooding is carried to increase the oil recovery factor and to intensify the development process. When we decide to maintain reservoir pressure by injection of water, we should solve the following tasks:

1) to determine the location of injection wells;
2) to determine the amount of water injected;
3) to determine the number of injection wells;
4) to establishing requirements for injected water.

4.1.1 Location of injection wells

The location of the injection wells is determined mainly by geological considerations. Choosing of wells locations are carried out with taking into account the specific geological conditions and state of development of field based on hydrodynamic studies and feasibility calculations. The main problem is in order to choose locations of injection wells in which ensure the most efficient connection between the injection zone and the selection zone and uniform displacement of oil by water. One of the main methods of effective communication between the injection zone and the selection zone is the maximum approximation injection line or injection wells to production wells. But this approach can lead to disruption uniform displacement of WOC.

Depending from the locations of water injection wells are distinguished such systems flooding:

- edge flooding;
- marginal flooding;
- inside contour flooding;
- block systems of development;
- focal flooding;
- pattern flooding;
- selective flooding;
- barrier flooding.

Edge flooding. Edge flooding is used for developing small deposits of oil reserves. Maintenance of pressure by edge flooding is effected by injecting water into special wells located outside the drainage boundary or the oil-bearing contour (external WOC) on a distance 100-1000 m (Fig. 4.2).

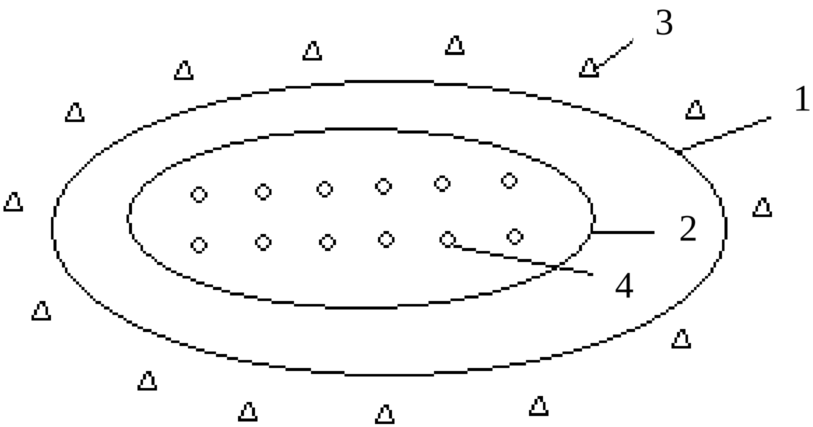


Figure 4.2 – Edge water flooding: 1 – external oil-bearing contour (external WOC); 2 – internal oil-bearing contour (internal WOC); 3 – injection wells; 4 – production wells

Inasmuch as water injection creates an artificial external drainage boundary in closer proximity to the producing zone, we have the question about concerning the optimal distance between the injection and recovery wells. Increasing the distance between the injection and recovery wells is good practice because the high-pressure gradients, what create near the injection wells don`t affect for shape of the drainage boundary and don`t cause fingering. However, if the distance between recovery and injection wells is more than 1.5-2 kilometers, the artificial drainage boundary is not very effective.

Now is a water flooding is rare.

In some cases, the specific geological features of formation make it necessary to place injection wells right on the drainage boundary (so-called marginal flooding).

Marginal flooding. Marginal flooding is used when injection wells located in oil-bearing part of deposit near to external oil-bearing contour (Fig. 4.3). It is used in low mobility or real estate WOC. Marginal flooding apply when:

- we have impair hydrodynamic communication with external reservoir zone;
- we should develop smaller deposits width not more than 4-5 km;
- we need to intensify the operation.

This flooding is used for fields, layers what have high permeability and low viscosity of oil. Marginal flooding is the least intensive type of inside contour flooding and it is the kind of transition between the edge flooding and inside contour flooding.

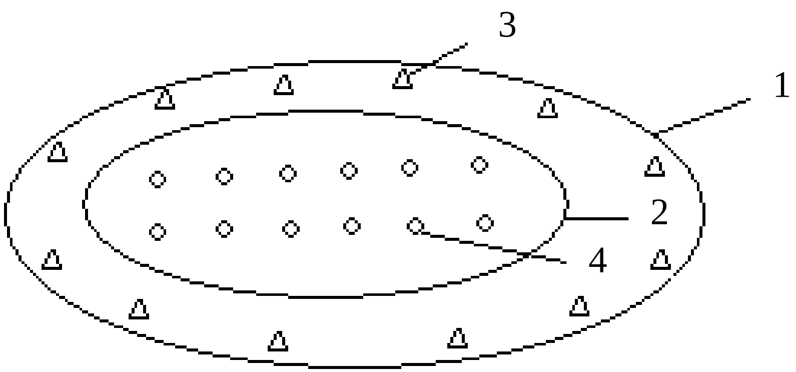


Figure 4.3 – Marginal water flooding: 1 – external oil-bearing contour (external WOC); 2 – internal oil-bearing contour (internal WOC); 3 – injection wells; 4 – producing wells

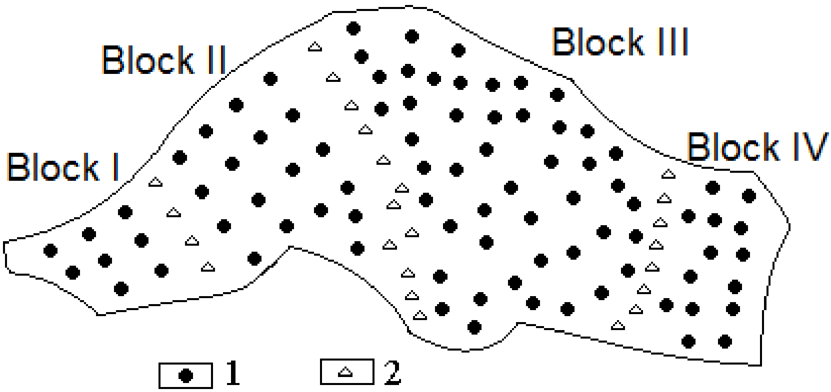
These results edge flooding and marginal flooding caused further improvement and development of oil fields led to the feasibility of using inside contour flooding.

Inside contour flooding. Inside contour flooding is used mainly for development of oil deposits of large areas. It is used on the Romashkinskoye field in Tatarstan, the largest in the U.S.S.R. in the early 50s. This flooding was used in 1948 on a small field Uisson in Arkansas in the USA. Later, inside contour flooding found application in other fields of the United States, including such large fields as Kelly-Snyder and Spraberri. The transition from the edge flooding to the inside contour flooding can significantly accelerate development Romashkinskoye field was a major step in the development of oil fields. Action to layer, in this case, is carried out through injection wells placed at varying schemes inside the oil-bearing contour. This system is the most intense action on oil deposit. The advantage of the inside contour flooding is a possibility to start developing from any area and, in particular, to introduce the development of the first area with the best geological and exploration characteristics, the largest reserves and high production flow rate of wells.

Inside contour flooding allows in 2-2.5 times increase the rate of development compared to the edge flooding significantly improve technical and economic indicators of development.

Block system of development is one of inner flooding contour systems.

Block development system. Block systems of development are used in fields of elongated placing rows of injection wells mostly in cross-section (Fig. 4.4). As shown in Fig. 4.4, the rows of water injection wells cut only deposit in certain areas (blocks) development. Reservoir there may be developed by blocks independently. Block systems of development have many advantages. Block systems can increase in 2-3 times the rate of oil recovery, reduce the number of injected water and accelerate input field in development compared to the edge flooding. The most modular distribution block system of development is acquired in the fields of Western Siberia (Russia).



1 – producing wells; 2 – injection wells
Figure 4.4 - Block systems of development

Focal flooding. Focal flooding is used as a supplement to the already undertaken inside contour flooding or edge flooding and aims at strengthening already carried out a system of development. Injection wells located in areas with a layer of a relatively low production flow rate of wells. In some cases, when a good understood geological structure of the reservoir focal flooding can be used as an independent system of development. For this flooding possible drilling one injection well or group of injection wells (Fig. 4.5). Focal flooding was first used in the fields of Tatarstan.

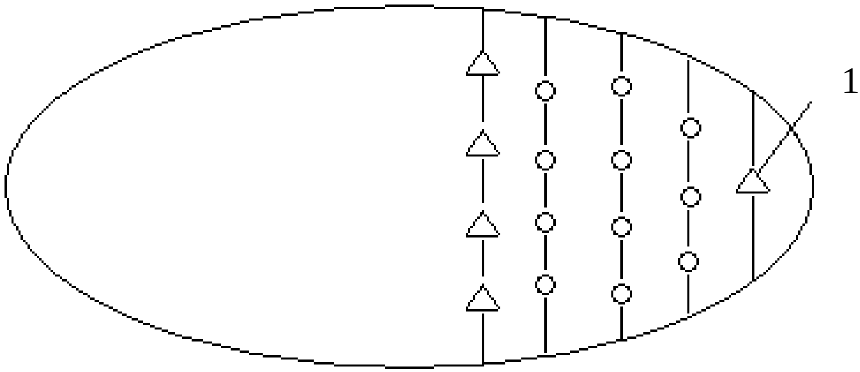


Figure 4.5 - Focal flooding: 1 – drilled well

Pattern flooding. Pattern flooding most intense action on the layer system, which ensures the on-highest rate of development. In the USSR, flooding was started in 1943 in the fields of Kazakhstan - Dosor and Makati. This system of flooding is used to develop reservoirs with very low permeability. Efficiency pattern flooding depends on the heterogeneity of the reservoir, the reservoir thickness, viscosity of the oil and the depth of the deposit. A feature of this system of flooding is the placement production and injection wells evenly on the area. Water injection is performed through the injection wells that are placed with production wells and between them hold the same distance. Pattern flooding systems used for experimental works to enhance oil recovery. Pattern flooding can be effectively used in the early stages of development under good learning geological feature of the reservoir. In this system producing and injection wells are placed at the uniform grids. There are four-, five-, seven-, and nine- systems. Formulas for definition flowrates and validities for each of these systems.

Selective flooding. Selective flooding is a form of pattern flooding, which is used in oil fields with significant heterogeneity as the focal flooding.

Wells not placed in a row, but based on the distribution of reservoir properties of the reservoir area. Location injection wells are chosen after drilling area and study reservoir properties according to industrial-geophysical and hydrodynamic researches. During those selected injection wells, pumping water that provide the most complete excavation around the reservoir, that is the well where the biggest productivity factor and the well, which discovered the layer of high permeability and good hydrodynamic coupling to the surrounding wells. Drilling carried out at a uniform triangular or square grids. All wells originally commissioned as oil producing. And then producing wells become injection wells.

Barrier flooding. Barrier flooding used in the development of gas-oil fields with a large volume of gas caps, when a possible simultaneous selection of oil from the oil part and gas from the gas cap. As a result of water injection into wells forms a water barrier, which "cuts off" the gas cap from the oil deposit. When the barrier flooding applies a single cutting oil and gas deposits in certain areas of self-development. Injection wells are placed in the area of GOC (gas-oil contact) and injection water and selection of oil and gas regulating such a way that there was displacement of oil and gas from water in case of exclusion of mutual flows of oil in the gas reservoir and the gas to the oil part (Fig. 4.6).

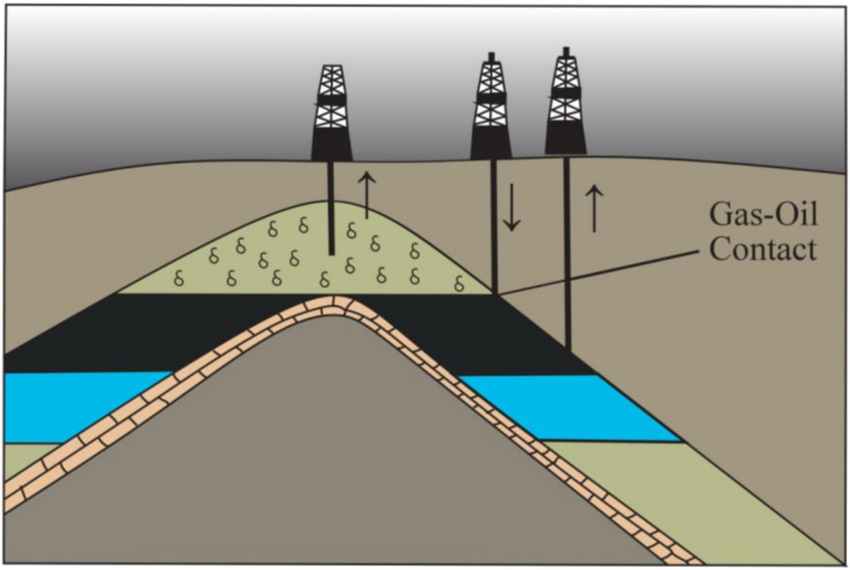


Figure 4.6 - Barrier flooding

4.1.2 Determination of the amount of water injected

The total volume of water that is injected depends on the projected selection of fluid put, the pressure at the line injection, and also from a collection and elastic properties of the layers. There are pressures: the pressure at the line injection and injection pressure.

The pressure at the line injection – it is the pressure in the row between injection wells on a distance from the well (σ - a half distance between the wells) (Fig. 4.7). Represented P_{line} .

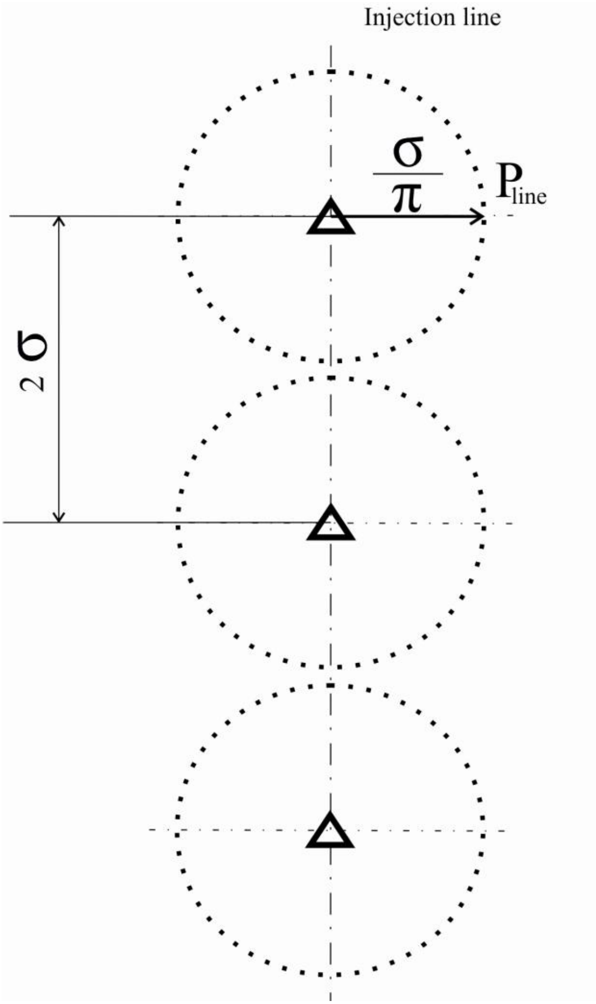


Figure 4.7 – About pressure at the line injection

Injection pressure - is the pressure at the head of the water injection well with pumping water into it. In practice waterflooding injection pressure ranges from 5 MPa to 16-20 MPa, and in some cases even 20-30 MPa and 40 MPa, accounting for an average of 13 MPa. The injection pressure should be greater than the pressure losses of water, which is pumped into the reservoir. Represented P_{inj} .

In general, the amount of water injected is determined

$$Q_{inj}=Q_{sel} + Q_{los}, \tag{4.1}$$

where Q_{sel} – the amount of fluids (oil + water), which are selected; Q_{los} – loss of water that escapes the contour.

Q_{sel} determined by hydrodynamic calculations. Q_{los} depends on the pressure at the line injection wells and the average reservoir pressure in the aquifer of the reservoir.

Depending on the values of pressure at the line injection and the average reservoir pressure for the contour of the reservoir are three cases:

1) If $P_{line} > P_f$, then the water pumped flows into the aquifer area. In this case $Q_{inj}= Q_{sel} + Q_{los}$. It is necessary to take into account the elastic properties of the reservoir and fluid out the line injection.

2) If $P_{line} < P_f$, then $Q_{inj}= Q_{sel} - Q_{los}$. This case is rarely used in practice.

3) When $P_{line} = P_f$ no loss of water and $Q_{los} = 0$. This case is used most often. In this case, the impact of external area completely isolated and reservoir works due to the energy of water injection. In this case, water is injected into injection wells completely used to displacement oil.

In the literature suggested many formulas for determination Q_{los}, one of which is

$$Q_{los} = \frac{kBh}{\mu_w}\frac{P_{line} - P_f}{\sqrt{3}\sqrt{\chi t}}, \tag{4.2}$$

where B - the length of injection line, m; χ - piezoconductivity factor, m^2/sec; t – the period of time, sec; μ_w - coefficient of dynamic viscosity of water (μ_w = 1 mPa·s).

To assess the degree of compensation selections of fluids from the reservoir injected water introduce the concept of factor compensation. There are factors of current and accumulated compensation.

A factor of current compensation - is the ratio of injected water to flowrates liquids that are selected, reduced to formation conditions per unit of time (year, month, day and etc.)

$$m_{cur} = \frac{Q_{inl} b_w}{\left(Q_{oil} b_{oil} + Q_w b_w' + Q_{los}\right) k}, \qquad (4.3)$$

where Q_{inj} - volume flowrate injected water under standard conditions; b_w – volume formation factor for the injected water ($b_w \cong 1{,}01$); Q_{oil} - volume flowrate for the oil under standard conditions; b_{oil} – volume formation factor for the oil; Q_w - volume flowrate selected water under standard conditions; b_w' - volume formation factor for the selected water, which is different from the volume formation factor for fresh water; Q_{los} – loss of water that escapes the contour; k - factor for the loss of water in the periodic work injection wells, under breaks in water lines and other technological reasons. This ratio is assumed to be k = 1,1-1,15.

A factor of current compensation shows how forcing compensated selection at any given time. According to the current values of the coefficient, compensation can make the following conclusions. If $m_{cur} < 1$ injection behind the selection and expect the average formation pressure should drop. If $m_{cur} > 1$ injection exceeds the selection and the formation pressure should rise. When $m_{cur} = 1$ should have been the stabilization of the current formation pressure at the current level, no matter what it was in early development.

A factor of accumulated compensation is the ratio of injected water to flowrates liquids that are taken to the consolidated formation conditions during the whole period of injecting

$$m_{ac} = \frac{\int_0^t \left(Q_{inj} b_B\right)(t)dt}{\int_0^t \left[\left(Q_{oil} b_{oil} + Q_w b_w{}' + Q_{los}\right)k\right](t)dt}. \tag{4.4}$$

4.1.3 Determination of injection wells number

In general, the number of injection wells

$$n_{inj} = \frac{Q_{inj}}{q_{inj}}, \tag{4.5}$$

where q_{inj} - the amount of water pumped into one well (acceleration), which is determined by the formula

$$q_{inj} = \frac{2\pi k_w h\left(P_{bh\ inj} - P_{line}\right)}{\psi \mu_w \ln \dfrac{\sigma}{\pi r_{rw\ inj}}}, \tag{4.6}$$

where k_w - phase permeability for water in the near wellbore zone of injection well k_w = (0.5-0.6)k; $P_{bh\ inj}$ – bottomhole pressure of injection well; P_{line} - pressure at the line injection; ψ - formation damage coefficient, ($\psi \geq 2$). Determined according to research by injection or industrial data obtained in similar fields; μ_w - coefficient of dynamic viscosity of water (μ_w = 1 mPa·s); σ – a half distance between injection wells; $r_{rw\ inj}$ – reduce radius of injection wells.

A half distance between injection wells is determined

$$\sigma = \frac{B}{2n_{inj}}, \tag{4.7}$$

where B - the length of the injection line.

Bottom hole pressure of injection well is determined by the formula

$$P_{bh\,inj}=\rho_w gH+P_{inj}-\Delta P_{los\,pr}, \tag{4.8}$$

where ρ_w – density of water (ρ_w = 1000 kg/m^3); g= 9.81 m/s^2 - acceleration of gravity; H – depth of injection well, m; P_{inj} - injection pressure, Pa; $\Delta P_{los\ pr}$ - pressure loss due to friction, which are determined by the Darcy-Weisbach equation, Pa.

Darcy-Weisbach equation has the form

$$\Delta P_{los}=\lambda\frac{H}{d}\frac{\upsilon^2}{2}\rho_w, \tag{4.9}$$

where λ - coefficient of hydraulic resistance that depends on the Reynolds number and the roughness of the pipe, $\lambda=f(Re,\ \Delta)$; d - the inner diameter of the pipe on which is pumping water; υ - velocity of injected water.

The first, determine the velocity of movement

$$\upsilon=\frac{Q}{F},$$

where F - sectional area of the pipe, m^2.

Reynolds number is determined

$$\mathrm{Re}=\frac{\upsilon d}{\nu},$$

where ν - kinematic viscosity of water.

If $Re<Re_{cr}$ (Re_{cr} =2320), then the mode of movement is laminar and λ determined by the Stokes formula $\lambda=\dfrac{64}{\mathrm{Re}}$.

If $Re > Re_{cr}$ (Re_{cr} =2320), then the mode of movement is turbulent and λ determined by the Blaziuses formula

$$\lambda=\frac{0{,}3164}{\mathrm{Re}^{0{,}25}}.$$

Substituting equations (4.6) and (4.7) in (4.5), we obtain an expression for the number of injection wells

$$n_{inj} = \frac{Q_{inj}\varphi\mu_w\left(\ln\frac{B}{2\pi r_{rw\,inj}} - \ln n_{inj}\right)}{2\pi k_w h\left(P_{bh\ inj} - P_{line}\right)}. \tag{4.10}$$

As can be seen from the equation (4.10) in the left and right sides of the equation is the desired number n_{inj}. The method of solution of equation (4.10) semigraphical. Let us take a number of values n_{inj} on the right side of equation (4.10) and each time counting n_{inj} on the left side. The calculation begins with one. The calculations are summarized in the Table 4.1.

Table 4.1 – Calculation of injection wells number

n_{inj} (given)	n_{inj} (calculated)
the right side of equation (4.10)	the left side of equation (4.10)

Building a graph (Fig. 4.8).

Scale axes are the same. Hold bisect and determine the number of injection wells. As shown in equation (4.10), the higher the bottom-hole pressure of injection wells, the less quantity of injection wells, and consequently, lower capital costs for process waterflooding. The injection pressure of injection wells depends on the number of injection wells.

The choice of injection pressure and the number of wells is based on economic calculations.

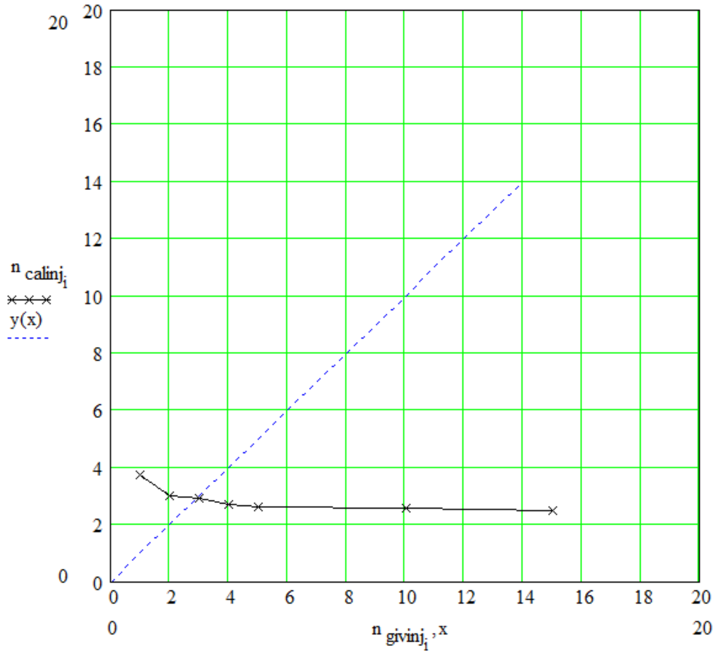


Figure 4.8 - Graph for definition n_{inj}

4.1.4 Requirements for injected water

Industrial implementation of secondary extraction methods and techniques to maintain reservoir pressure by waterflooding in the oil reservoir is closely associated with finding appropriate sources of supply. Consumption of water during flooding is 1.5-2 m^3 of water per 1 ton of oil produced. However, under pattern flooding depleted reservoirs need 10-15 m^3 of water per 1 ton of oil produced. Therefore, the question is, to have a source of water supply. At the same time as the issue is not only the quantity but also the quality of water.

Under flooding oil deposits could be used the following sources of water:

1) surface water (from rivers and lakes);
2) upper water horizons;
3) water formation of oil-bearing horizons;
4) lower water horizons.

Only a few cases of water supply sources may be eligible for flooding without preparation. In most cases, have to start preliminary preparation of water.

In water treatment, depending on the need to perform the following steps: 1) remove the oil; 2) aeration; 3) sterilization; 4) stabilization of water; 5) coagulation; 6) defending; 7) filtering.

The suitability of water used for injection into reservoirs usually determined in the laboratory by filtering water through the core. Water is considered suitable for injection into reservoirs if the permeability of the core remains constant. Reliable data on the quality of water used for flooding and about the optimum pressure at the line injection can only be the result of water injection test into oil deposits.

The injected water into deposit pose the following requirements:

1. Water must not enter into a chemical reaction with formation waters, because of the possible loss of sediment and pore sealing layer.

2. The number of solids in water should be small because it can lead to contamination of the wellbore zone and loss acceleration of well. The content of impurities in the water taken from the experience of pumping water.

3. Water shall not contain impurities hydrogen sulphide and carbon dioxide, in order not to cause corrosion of the surface and underground equipment.

4. Injected water should not cause swelling of clay particles, leading to clogging of pores in the reservoir and fracture wellbore zones.

5. Water used for injection should be subjected to biological treatment cultivation from microorganisms.

The injected water should have a good ability to wash oil from rock. For this purpose, conduct water treatment using chemicals.

§4.2 MAINTENANCE OF RESERVOIR PRESSURE BY GAS INJECTION

Pressure maintenance by injecting gas into the up structure parts of the reservoir is most frequently used under conditions naturally favouring the development of a solution gas drive (low edge water activity, a small difference in reservoir saturation pressure) and also when there is a natural gas cap.

Considering a pressure maintenance project with the injection of gas into the up structure part of the reservoir, one must evaluate the practical and economic advantages of the project in each particular case. It must be borne in mind that reservoir pressure, particularly in the initial period of production, may be very high and costly equipment will be required to develop the high pressures that are necessary for a successful operation. It is also necessary to study carefully the geological conditions of the reservoir. For the success of the operation the structure not be too flat (the dip should preferably be not less than 12-15°); a low-dipping structure has an adverse effect on the gravitational separation of oil and gas.

It is desirable that the reservoir be uniform permeability and the oil of low viscosity. In nonhomogeneous reservoirs and in the presence of a large number of tectonic faults and fissures it is difficult to control the movement of the gas through the reservoir rock.

The best results are obtained when a pressure maintenance project is started early. However, field practice shows that gas injection can also be applied, though with less success, during later stages when a considerable quantity of gas has already evolved from the oil.

Gas injection wells should be located near the crest of the reservoir. Natural oil gas is the best working agent, but if not available in necessary quantities, air can also be injected provided there is no gas cap. The injection of air into a gas cap is undesirable as it will considerably impair the quantity of the gas.

In designing the compressor stations it must be borne in mind that injection pressure is usually 15-20% higher than the formation pressure.

The quantity of gas to be injected into a well can be established experimentally by determining the injectivity index or it may be calculated approximately. In field practice, depending on the local conditions, 10000 to 25000 m^3/day of gas is injected into wells at pressures from 5 to 9 MPa.

To prevent reservoir pressure decline, the quantity of gas injected should be not less than the total volume of fluid withdrawals.

In the majority cases, however, only the gas that is produced is recycled, and even not all of that because some are consumed to cover the field needs. If 70-80% of the gas produced is recycled, this is generally regarded as good pressure maintenance practice. Of course, this does not make up completely for the expended formational energy but nevertheless, the process of pressure decline is much retarded.

Considering the high working pressure required for a gas-injection project, in order to save power the gas is supplied to the compressor from high-pressure gas-gathering lines and so-called *booster compressors* are used.

Gas injection is less efficient economically than water injection because it is necessary to compress the gas to a pressure greater than the reservoir pressure. Not much of the power used in compressing the gas is compensated by its lower hydraulic resistance, as compared with water.

All schemes of location water injection wells can be used not only for injection water but for injection gas into the oil deposit.

Pressure maintenance by injecting gas has not found wide use and is used mainly in depleted oil fields, where reservoir pressure is low.

The amount of gas needed for injection into the reservoir only for pressure maintenance at the current level will be equal to the sum of volumes of oil, water and gas under to formation conditions

$$V = V_{oil} + V_w + V_g,$$

where V – the amount of injected gas; V_{oil} - oil withdrawal per day; V_w - water production per day; V_g – gas extraction per day.

The values V_{oil} and V_w determined by the actual data, taking into account the volume formation factors for the oil and water

$$V_{oil} = V_{oil0}\, b_{oil}; \quad V_w = V_{w0}\, b_w,$$

where $V_{oil0,}$ V_{w0} – flow rate oil and water per day under standard conditions.

V_g under formation pressure and the temperature is defined by the formula

$$V_g = \frac{\left[V_{g0} - \alpha\left(P_f - P_0\right)V_{oil0}\right]P_0 z T_f}{P_f T_0}, \tag{4.11}$$

where V_{g0} - gas extraction per day under standard conditions, m^3; α - gas solubility coefficient m^3/m^3·Pa; P_f - formation pressure, Pa; P_0 - pressure under standard conditions (P_0 = 0.1 MPa), Pa; z - gas compressibility factor under formation pressure and formation temperature; T_f - formation temperature, K; T_0 - temperature under standard conditions (T_0 = 293 K), K.

Gas injection in wells through tubing that is lowered to the top of the filter column. Annular space between the tubing and casing packer block, which is set at the lower end of the tubing. The aim is to isolate the column, which does not always withstand high injection pressures, and the depleted fields casing is leaking due to corrosion.

§5 MAIN HYDRODYNAMIC CALCULATIONS OF DEVELOPMENT PARAMETERS WITH TAKING IN ACCOUNT HETEROGENEITY OF PRODUCING LAYERS

Earlier during of all our calculations we have assumed that reservoir is uniform formation with its permeability equal to k_{mid}. However, in practice all reservoirs are characterized by a significant change of permeability along the horizontal and through the thickness of the formation. In addition, reservoirs are heterogeneous by its geological features and other properties, which has been caused by sedimentation and further metamorphoses of the rock.

The term "heterogeneity (non-uniformity)" refers to the properties of the pore reservoir, caused by a change in its structural and lithological characteristics. The distribution of any parameter may be logical or random; therefore, such patterns and types of formation heterogeneity distribution are defined:

-regular distribution of parameters in a nonhomogeneous continuous formation;

-random probabilistic distribution of parameters in a non-uniform continuous formation;

-zonal inhomogeneity, when within the reservoir there are zones which differ significantly from other zones of the reservoir;

-layer heterogeneity, when in the section of the formation singled out different stratums (separated from each other by impermeable layers) with different values of permeability and porosity.

Data about permeability, porosity, oil, gas, water saturation, and carbonate content are obtained by analyzing core samples collected during the drilling process. Two approaches are applied in studying the heterogeneity of rocks:

- deterministic: maps for the distribution of heterogeneity along the horizontal and the scheme of distribution of heterogeneity through the thickness of the productive stratum are generated (both are based on the information obtained in the geological-geophysical and industrial study of the non-uniformity of the reservoir under different parameters);
- probabilistic: by applying mathematical statistics establishing distribution law, which match actual distribution.

However, it is more useful to use this both approaches.

For reservoir engineering, the most important parameter is permeability. Therefore, during the calculations it is necessary to establish the distribution law, cumulative distribution function and plot the distribution polygon.

The study of heterogeneity, in particular the establishment of patterns of permeability change, is carried out using the following basic statistic characteristics: mathematical expectation, variance, coefficient of variation, and others. These mathematic criterias enable us, although not fully, to express quantitatively and qualitatively the characteristic of heterogeneity change through the formation:

- the study of heterogeneity with the aim of making geological correlation;
- discovering the influence of heterogeneity on reservoir development and field development strategy.

For establishing statistic characteristics and comparison of production, target graphical dependencies are plotted. They are setting up the connection between researched parameter (in most cases it is permeability k) and frequency of occurrence n. The significance of change in permeability is described by the permeability distribution polygon or, in other words permeability spectrum.

Permeability distribution polygon - graphical dependency that displays statistical correlation between researched parameter k (permeability) and the frequency of occurrence of this parameter, while points by frequency connected by smooth curve. The typical polygon is displayed on Fig. 5.1. Every graph has a special peak-point k_{mod} that called modal value or mode.

Modal value - the value of permeability that occurs the most often.

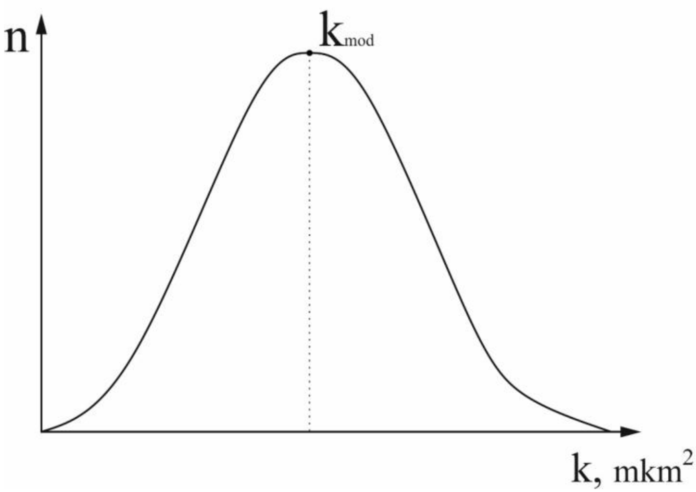


Figure 5.1 - Permeability distribution polygon

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There are great number of types of polygons, a few examples displayed on Fig. 5.2. The most homogeneous formation would have the graph similar to graph number 1, because it has the smallest range of values. The most heterogeneous formation would have graphic similar to graph number 4, because it has the widest range of values.

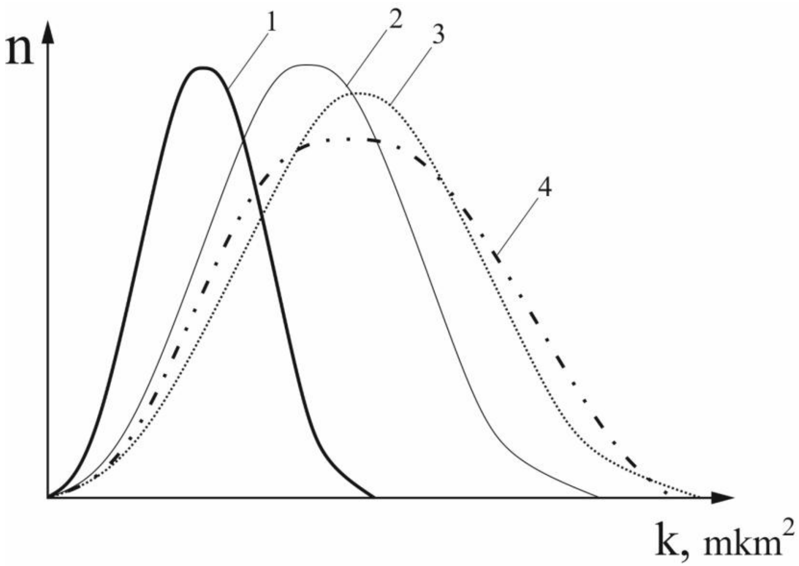

Figure 5.2 - Different types of permeability distribution polygon

Detailed study of formation's non-uniformity results in fact that there are several types of permeability distribution. The most frequent are:

- bell-shaped(normal) distribution;
- gamma-distribution;
- log-normal distribution;
- balanced distribution;
- and others.

The main statistical characteristics of the studied parameters are the following values:

- ***mathematical expectation*** or in other words expected value (average weighted parameter):

$$k = {\sum_{i=1}^{n} k_i n_i} \Big/ {\sum_{i=1}^{n} n_i}, \tag{5.1}$$

where k_i, n_i taken from permeability distribution polygon;

- ***variance (mean-square deviation)*** defines the fluctuations of the actual value of the parameter near the mean in absolute units

$$\sigma = \pm \sqrt{\frac{\sum_{i=1}^{n} (k_i - k)^2 n_i}{\sum_{i=1}^{n} n_i}}, \tag{5.2}$$

- ***coefficient of variation***, which is ratio of dispersion to mathematical expectation

$$\vartheta = \pm \sigma / k, \tag{5.3}$$

shows fluctuations of the parameter in decimal quantity from the average.

Considering the fact that not all of the possible research activities could be done the average values of parameters could be estimated with errors (non-sampling errors). Non-sampling errors could be estimated as:

$$\Delta = \pm \frac{\sigma t}{\sqrt{N}}, \tag{5.4}$$

where Δ - limiting sampling error; σ - variance; N - number of samples; t - coefficient with value depended from given probability (t=1 when probability 0.68; t=2 when probability 0.85; t=3 when probability reaches 0.97);

In case when the error value is set by the regulation (it should not exceed the pre-set value), in order to prevent error value overrunning the established limits at a predetermined probability, by using equation (5.4), determine the number of models that need to be analyzed:

$$n = \sigma^2 t^2 \big/ \Delta^2 .$$

Due to the fact that reservoir is characterized as highly non-uniform there are several methodologies that gives us ability to determine the change of permeability horizontally and though the depth. The most common used are VNII-1, VNII-2 and manyothers.

5.1 VNII-1 methodology

Created by professor Borisov, this methodology is one of the first of it's kind and the most used. It is based on permeability distribution polygon, relying on which Borisov created reservoir model that consists of equal cross sections and stacked streamlines.

Reservoir model - it is range of layers of streamlines, which stretch from one corner to another through the whole reservoir. By creating the general concept about reservoir consisting of streamlines, we take that at every moment of time, the velocity of filtration flow is proportional to the permeability. By solving the case for one streamline, and then summarize the flow rate of all streamlines, it is possible to obtain a solution for the whole reservoir, with the separation of a liquid that has passed through the reservoir with separating on oil and water.

After developing general understanding about reservoir running calculations are carried out in such order.

The permeability distribution polygon should be rebuilt from the coordinate system "*k*-*n*" to "æ-*n*(æ)".

$$\chi = \frac{k_i}{k_{moo}}; \quad n(\chi) = \frac{n_i}{\sum n_i},$$

where (k_i, n_i, k_{mod} are taken from permeability distribution polygon). Further transformation of permeability distribution polygon involves defining of a new permeability distribution polygon with taking into account formation water-flushing whereas velocity of filtration flow assumed as proportional to permeability and incompleteness of oil displacement by water is taken into account by residual-oil saturation. Transformed polygon of distribution of permeability in the analytical form is written as follows:

$$n_1(\chi) = n(\chi)\left[1 - \frac{z_f}{1-\rho_{ro}-\rho_{bw}}\right] + \frac{z_f}{2(1-\rho_{ro}-\rho_{bw})} \times \frac{1}{\sqrt{\chi}} \int_{\chi}^{\infty} \frac{n(\chi)}{\sqrt{\chi}} d\chi, \quad (5.5)$$

where n_1(æ) - auxiliary function; z_f - oil saturation at the front water-oil displacement; ρ_{ro} – residual oil saturation; ρ_{bw} - saturation of bound water; n(æ) - distribution density of permeability, the nature of random variable distribution.

Auxiliary function n_1(æ) is principal in defining auxiliary functions F_1(æ) and F_2(æ), using which gives to us ability to estimate oil-extraction rate and water content in wellbore fluids. The plot of auxiliary function n_1(æ) can be seen in Fig. 5.3.

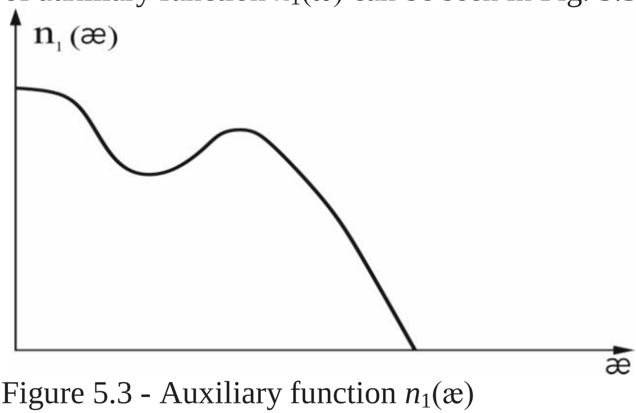

Figure 5.3 - Auxiliary function n_1(æ)

Auxiliary functions F_1(æ) and F_2(æ) may be determined as:

$$F_1(\chi)=\int_0^{\chi}\left[1-\frac{\int_0^{\chi} n_1(\chi)d\chi}{\int_0^{\infty} n_1(\chi)d\chi}\right]d\chi; \quad (5.6) \qquad F_2(\chi)=\frac{\int_0^{\chi} \chi n_1(\chi)d\chi}{\int_0^{\infty} \chi n_1(\chi)d\chi}. \quad (5.7)$$

The graphical dependencies of F_1(æ) and F_2(æ) can be seen in Fig. 5.4.

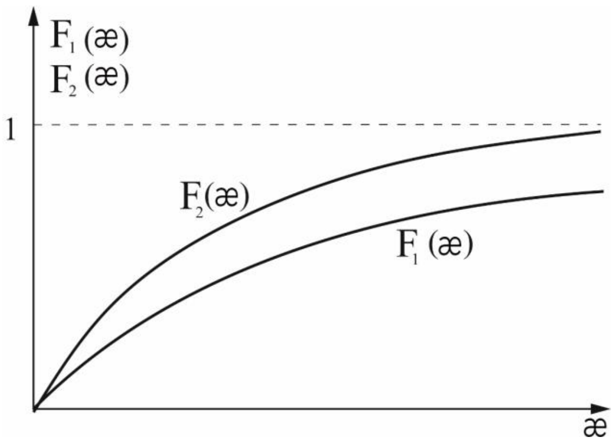

Figure 5.4 - Auxiliary functions F_1(æ) and F_2(æ)

Auxiliary function F_1(æ) is used for oil-extraction rate estimation.

$$\eta=\eta_0\,\frac{F_1(\chi_i)-F_1(\chi_{i-1})}{\chi_i-\chi_{i-1}}, \qquad (5.8)$$

where $æ_i$ and $æ_{i-1}$ - the ratio of permeability for the two extreme sections of the reservoir where the oil extraction is estimating; F_i and F_{i-1} - auxiliary functions for two values of $æ_i$ and $æ_{i-1}$, which can be calculated by the formula (5.6), η_0 - potential oil extraction, which estimated as:

$$\eta_0 = \frac{1-\rho_{ro}-\rho_{bw}}{1-\rho_{bw}}. \qquad (5.9)$$

Potential oil extraction and $\rho_{r\ o}$, $\rho_{b\ w}$ are estimating in reservoir engineering laboratories. Let's compare formula (5.8) with Krylov's formula that listed next:

$$\eta = k_{DE} \cdot k_{SE}. \qquad (5.10)$$

From this comparison follows that displacement efficiency defines potential oil-extraction and sweep efficiency can be outlined by F_1(æ) dependency.

Displacement efficiency k_{DE}- the ratio of the oil displaced from the flooded reservoir to the initial volume of oil in the reservoir. Displacement efficiency in general depends of depends on the ratio of oil viscosity to water viscosity and permeability coefficient.

Sweep efficiency k_{SE} - the ratio of volume of the reservoir which water passed to the initial oil-saturated volume of reservoir. In other words the ratio of the rock volume covered by displacement to the total volume of the oil-saturated rock. It takes into account oil losses along the horizontal and through the thickness of the reservoir. It also can be represented as a product of the following coefficients:

$$k_{SE} = k_1\, k_2\, k_3\, k_4,$$

where k_1 - coefficient that takes account of non-uniformity of reservoir (0.7-0.8); k_2 - coefficient that takes account of lens-shape of formation and its interruption (0.7-0.9); k_3 - coefficient that takes account of kinematics of filtration flow (0.7-0.8); k_4 - coefficient that takes account of oil losses in the rows that cut the area (0.8 -0.9).

Auxiliary function F_2(æ) estimate oil content in wellbore fluids. In general, this function can be found as:

$F_2(\chi) = \dfrac{Q_{oil}}{Q_{oil} + Q_w}$, accordingly, if we know the content of oil in wellbore fluid, we can determine the water content, in other words water cut n_w,

n_w=1-F_2(æ).

In order to determine the auxiliary functions F_1(æ) and F_2(æ), we need to integrate the auxiliary function n_1(æ). Then, as a result of the calculations, plotting the following graphic dependencies (Fig. 5.5).

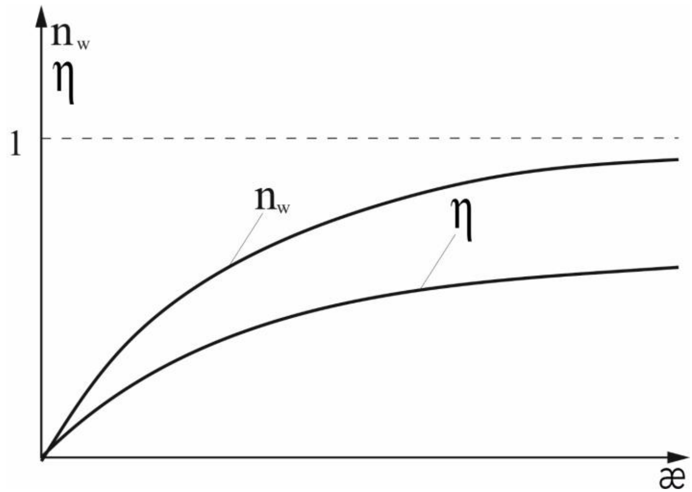

Figure 5.5 - Graphic dependencies oil recovery and water cut from æ

When we solving the problem where the reservoir represented by the section from the initial oil-water contact position to the line of wells of the first row, sweep efficiency can be estimated as:

$$k_{SE} = \frac{F_1(\chi_i)}{\chi_i}.$$

Since, the auxiliary function F_1(æ) for the water-saturated part of the reservoir will be equal to zero, so when using graphs to assess the oil extraction and water content in the well production, we pre-determine the value:

$$\chi_i(t) = (1 - \rho_{ro} - \rho_{bw}) F_1(\chi_\infty) \sum \frac{V_i}{Q_i(t)}, \qquad (5.11)$$

where: $(1-\rho_{r\ o}-\rho_{b\ w})$ – amount of water that entered to the formation; F_1(æ)$_\infty$ – value of function F_1(æ), when æ $\to \infty$; V_i – the volume of pore space, which is located between the sections of *i*-row and *i-1*-row; $Q_i(t)$ – the total amount of water that entered the formation from the start of development and till the time *t*.

Using equation (5.11), we will determine the next value:

$$\sum \frac{Q_i(t)}{V_i} = (1 - \rho_{ro} - \rho_{bw}) F_1(\chi_\infty) \Big/ \chi_i(t). \qquad (5.12)$$

Then we define left part of equation as τ:

$$\frac{Q_i(t)}{V_i} = \tau, \qquad (5.13)$$

which in turn means the multiplicity of washing, in other words he ratio of the pumped volume of water to the pore volume.

While taking into account the multiplicity of washing and dependence (5.12), the graphic dependencies of n_w(**æ**), η(**æ**) now are rebuilt depending on τ. The plots of $n_w(\tau)$, $\eta(\tau)$ shown on Fig. 5.6.

By calculated values of τ and using graphic dependencies, we can write the equation of disconnection of series of wells:

$Q_i(t) + Q_{i+1}(t) + Q_{i+2}(t) = Q'_i(t) + Q'_{i+1}(t) + Q'_{i+2}(t)$, (5.14)

where the left side – oil flow rates of well rows in the end of *i*-stage, the wright side – oil flow rates of well rows at the beginning of *i*+1 stage.

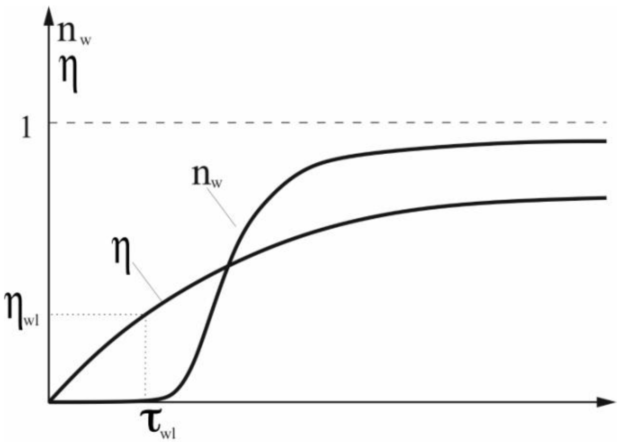

Figure 5.6 - Graphic dependencies oil recovery and water cut from τ

§6 CONTROL AND REGULATION OF OIL FIELD DEVELOPMENT

Regulation overview.

Describe the key laws and regulations that make up the general legal framework regulating oil activities. Are there any legislative provisions that allow for expropriation of a licensee's interest and, if so, under those conditions

The Petroleum Act 1998 governs oil and gas exploration and production activities in the UK. This Act vests ownership of petroleum in the UKCS in the Crown and empowers the secretary of state for DECC to grant licences for the exclusive right to search for, bore for and extract petroleum in the area covered by the licence. Licences are acquired through competitive licensing rounds held each year by DECC. A company will make (either by itself or as part of a joint venture) an application for a specific area. Licences may also be acquired through asset transfers between companies, and the consent of DECC is required prior to any licence assignment. The conditions of a licence (known as ‘model clauses’) are set out in secondary legislation, which for current offshore production licences is the Petroleum Licensing (Production) (Seaward Areas) Regulations 2008. The model clauses set out in detail the conditions for the licence, including term, licence surrender, record-keeping, working obligations, appointment of operator, measurements and pollution. In awarding licences, DECC must also comply with the Hydrocarbons Licensing Directive Regulations 1995, which set out additional rules EU member states have to follow when issuing petroleum licences. In addition to the regulatory requirements, there are a number of voluntary industry-based codes of practice to which many UKCS licensees have signed up to. ICOP is intended to facilitate access by a third party to oil infrastructure in the UKCS such that the parties involved can agree fair and reasonable terms. The fallow acreage initiative places pressure on licensees to deliver activity on old licences where companies have not been active for some time or relinquish licences in order for the acreage to be offered to other companies. With respect to transfers of licences, the Commercial Code of Practice establishes an agreed framework to minimise resources spent on negotiations and promote positive commercial behaviour. There are no current legislative provisions that allow for expropriation of a licensee’s interest; however, as the terms of a licence may be unilaterally altered by the government, any change in the law may allow for expropriation of a licensee’s interest.

Identify and describe the government regulatory and oversight bodies principally responsible for regulating oil activities.

DECC is the government authority primarily responsible for the development and regulation of the oil and gas industry in the UK. DECC was established in October 2008 following a transfer of powers from the Department of Business Enterprise and

Regulatory Reform. DECC administers oil and gas regulatory activities, including licensing, development consent, fiscal policy, environmental policy and decommissioning. Other regulatory bodies include the Health and Safety Executive (the HSE), which is responsible for health and safety, and includes the Hazardous Installations Directorate, which is responsible for regulating and promoting improvements in health and safety across the offshore oil and gas sector (Fig. 6.1).

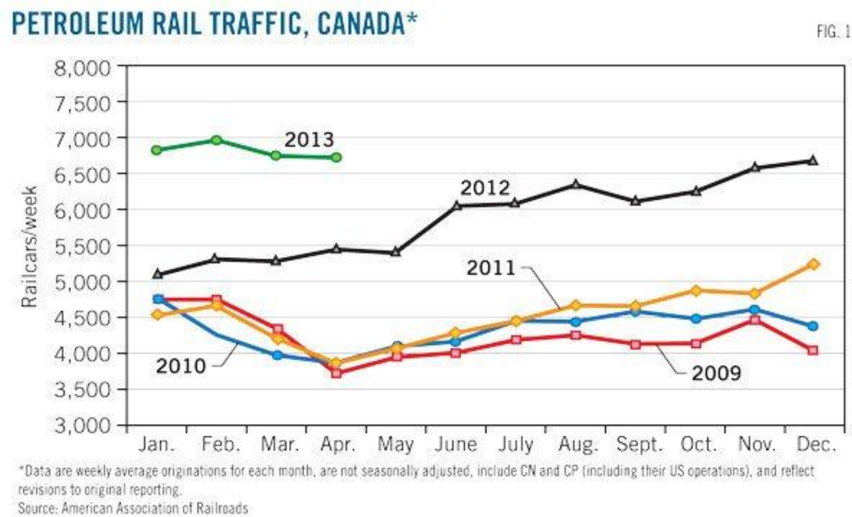

Figure 6.1- Regulation in Canada

What government body maintains oil production, export and import statistics

Responsibility for oil production, export and import statistics is with DECC. The Office for National Statistics is the central data source, where the statistics are produced to a high professional standard.

Who holds title over oil reservoirs! To what extent are mineral rights on private and public lands involved Is there a legal distinction between surface rights and subsurface mineral rights!

The Crown (through the Petroleum Act 1998) holds all title and rights to oil reservoirs within the UK and its territorial waters. DECC (on behalf of the Crown) has the power and discretion to grant licences to persons deemed fit to search for and extract oil and to further distribute and sell such oil in the market.

What is the general character of oil exploration and production activity conducted in your country.

Are areas off-limits to exploration and production! UK oil exploration and production activity is predominantly conducted offshore. Such activities are regulated by a licensing regime. Each licence covers a particular area, and there are separate licensing regimes for onshore and offshore exploration and production activities. Such activities (whether onshore or offshore) can be restricted for environmental, conservation or military reasons. DECC is required to carry out a strategic environmental assessment on areas proposed to be licensed to examine the impact of such activities on the environment.

What government body regulates oil exploration and production in your county!

How are rights to explore and produce granted! What is the procedure for applying to the government for such rights! DECC is the government body responsible for the regulation of oil exploration and production activities in the UK. Regulation is by a licensing regime rather than a production sharing arrangement. Applications for a licence are made (either individually or through a joint venture) to DECC as part of a formal annual licensing round that is advertised online and in the European Journal. All applications are made in a prescribed form and companies applying for a licence must be registered in the UK, either as a company or as a branch of a foreign company (see question 16). The timing for the application will vary depending on the size of the licensing round. In the simplest case (out-of-round with no environmental complications) it can take less than three months from the application. However, in a large licensing round with many licences and applicants it can take up to two years. There are currently two types of offshore licence awarded by DECC: the ‘exploration’ licence and the ‘production’ licence. Under a seaward petroleum exploration licence, seismic surveys and shallow drilling can be performed in acreage not already licensed. Other parties may hold an exploration licence over the same area, and it is therefore a non-exclusive licence. Under a seaward petroleum production licence, the licensee is granted the right to search for, bore for and extract hydrocarbons from the UKCS in the area prescribed under the terms of the licence for the full life of the field from the exploration phase and development to decommissioning. Three subcategories of production licence exist. The most common of these is the ‘traditional licence’. Potential applicants must be able to demonstrate financial, technical and environmental capability in order to be successful. The ‘promote’ licence (introduced in 2002) is designed to award smaller companies with production rights and allow a two-year period in which to obtain the requisite financial and technical capabilities prior to development. The ‘frontier’ licence (introduced in 2003) recognises the difficulties in sourcing oil in remote areas of the UKCS (such as the deep waters west of Shetland) and permits screening over a large area to look for a wide range of prospects. Onshore production is governed by the onshore production and development licence, which follows a similar form to the offshore licences described above.

Does the government have any right to participate in a licence!

If so, is there a maximum participating interest it can obtain and are there any mandatory carry requirements for its interest? Does the government have any right to participate in the operatorship of a licence? The government does not have the right to participate and be carried in a licence.

If royalties are paid, what are the royalty rates? Are they fixed? Do they differ between onshore and offshore production? Aside from tax, are there any other payments due to the government? Are there any tax stabilisation measures in place!

Royalties are no longer payable under a licence. Licences do carry a small annual charge, known as a ‘rental’, which is due on each anniversary of the date of the licence. There are no tax stabilisation measures in place, demonstrated in March 2011 when the budget raised tax on oil and gas output from 20 per cent to 32 per cent overnight.

What is the customary duration of oil leases, concessions or licences!

Offshore licences

There are three types of offshore licence (traditional, frontier and promote), and each licence comprises three terms. A licence will expire automatically at the end of each term, unless certain conditions allowing the licensee to advance to the next term have been fulfilled.

Traditional licence

The duration of a traditional licence is split into successive terms of four, four and 18 years. To progress from the initial to the second term, the licensee must have completed a work programme as approved by DECC and relinquished a minimum of 50 per cent of the acreage under the licence. If, during the second term, DECC has approved the development plan and all of the acreage outside that development has been relinquished, the licence may continue into the third term. DECC may exercise its discretion to extend the third term beyond the prescribed 18-year period if production is ongoing

Frontier licences

The duration of a frontier licence is split into successive terms of six (which is further subdivided into an initial two and then four-year period), six and 18 years. By the end of the third year of the first term, the licensee must have relinquished 75 per cent of the licence area. At the end of the sixth year, the licensee must relinquish a further 50 per cent of the remaining acreage. This equates to a total relinquishment of seven-eighths of the original licence area by the end of the initial term. DECC may, in exceptional circumstances, where prospectivity can be demonstrated over more than 25 per cent of the licence area, allow, at its discretion, a licensee to relinquish only 50 per cent of the acreage by the end of the third year. However, the licensee would still need to relinquish all but one-eighth of the original licence area at the end of the initial term, and must have completed the work programme in order to progress from the initial to the second term

A new type of frontier licence for the areas west of Scotland was introduced in the 26th licensing round announced in January 2010. The new frontier licence differs from the original frontier licence in that the first of its three terms is three years longer. This is in recognition of the particularly challenging nature of the geographical area where it applies and the relative scarcity of geophysical data.

Promote licences

The duration of a promote licence is split into the same successive periods as a traditional licence. However, the licence will expire at the end of the second year if DECC is not satisfied that the licensee has sufficient financial, technical and environmental capacity to undertake the work programme. At the end of the second year the licensee must also decide whether to ‘drill or drop’, in essence the licensee must make a firm commitment to DECC to drill a well in order for the licence to continue. Having committed to drilling, the licensee then has until the end of the initial period in which to drill.

Onshore licences

The duration of an onshore exploration and development licence is split into successive periods of six, five and 20 years. The licensee must complete the agreed exploratory work programme in the initial term before advancing to the second term. A development plan must then be approved during the second term before progressing to the third production term. In addition, the Fallow Initiative may apply to certain blocks and discoveries under a licence. Blocks and discoveries are considered fallow after three years if there has been no significant activity such as appraisal drilling, dedicated seismic acquisition or extended well testing. Ultimately, fallow blocks and discoveries, if not ‘rescued’, will be re-licensed.

For offshore production, how far seaward does the regulatory regime extend!

The regulatory regime extends to the UK’s territorial seas and the UKCS. The UK territorial sea extends from the low water mark (established by the Territorial Waters Order 1964) for 12 nautical miles. The designated area of the UKCS has been redefined over the years through a series of designations under the Continental Shelf Act 1964, following boundary agreements with neighbouring states. The Continental Shelf (Designation of Areas) (Consolidation) Order 2000 consolidated all previous designated UKCS boundaries. Recently, the Continental Shelf (Designation of Areas) Order 2001 designated the continental shelf in the Irish Sea as an area in which the UK may exercise its rights.

Is there a difference between the onshore and offshore regimes!

Is there a difference between the regimes governing rights to explore for or produce different hydrocarbons? The onshore and offshore regimes are historically similar, although there are distinctions in the means of designating licence areas. Offshore uses a ‘grid system’ for the designation (quadrants of 1 degree latitude by 1 degree longitude, split into ‘blocks’ of 25km by 10km). Onshore does not use a grid system, because the blocks are not regular and are much smaller than offshore. In addition to the regulatory regime, onshore operations must also adhere to the usual rules of Scots land law in Scotland and English land law in England and Wales (as exemplified by Bocardo v Star Energy, where, despite having obtained the licence to get petroleum, nominal damages were awarded against an oil company for its failure to obtain landowner consent to drill diagonally through strata beneath the land). Each of crude oil, gas and shale gas fall under the definition of 'petroleum' in the Petroleum Act 1998 and are therefore governed by the same regime.

Which entities may perform exploration and production activities!

Describe any registration requirements. What criteria and procedures apply in selecting such entities? Companies may only perform exploration and production activities in the UK under a licence. Applications for a licence are made (either individually or through a joint venture) to DECC as part of a formal annual licensing round. The licensing round is advertised online and in the European Journal. All applications are made in a prescribed form and companies applying for a licence must be registered in the UK, either as a company or as a branch of a foreign company. DECC considers each application on a case-by-case basis and will require a company to demonstrate its financial worthiness (that it is able to finance its share of the relevant work programme for the licence in question). With regard to technical capability, non-operators are not required to demonstrate a high level of technical expertise. Companies wishing to be appointed as operator are considered against additional criteria including previous experience, technical expertise and environmental awareness.

§7 FORECASTING DEVELOPMENT INDICATORS

Technological indicators of development at the stage of design determine the results of hydrodynamic calculations. To obtain these results need to have a large number of factors (the oil drives, parameters of the reservoir, parameters of the fluids, operating conditions of wells, etc.). Accurate knowledge of these data, especially in the early development unlikely. Therefore, to do the forecasting.

Forecasting – it is a prediction installation of further development, i.e. the course of the process of development in the future. There are forecasting oil production worked well-day and forecasting oil production under characteristics water-oil displacement.

7.1 Forecasting oil production worked well-day

Forecasting oil production worked well-day – it is forecasting oil production using the results of previous development. It is performed in the following order.

The study evidence of oil set basic patterns in the changes of oil in recent years. The dynamics of oil production in time trace using charting. In constructing graphs on the vertical axis – oil production, and the horizontal axis - time. Since the operation field is constantly changing a number of wells, the construction schedules when oil production is set to worked well-day. After plotting selected analytical expression curve of production over time. With regard to the prediction of oil wells worked on a day widely used in oilfield practice was the formula:

$$q_{oil}(t) = a \cdot t^{-b}, \tag{7.1}$$

where *a*, *b* - coefficients are determined using actual processing results.

The input data for the calculation of prediction for oil production flowrate for the worked well-day are:

Years of development	Flowrate for the worked well-day

The coefficient a and b are determined from a system of equations:

$$\begin{cases} \sum \log q_{oil}(t) = n\log a - b\sum \log t, \\ \sum \log q_{oil}(t)\log t = \log a \sum \log t - b\sum (\log t)^2; \end{cases} \quad (7.2)$$

where n – the amount of years.

For solving the system of equations (7.2) the actual flow rate data changes over time more convenient to file as a Table 7.1.

Table 7.1 – Initial data for forecasting

t, years	Flowrate, $q_{oil}(t)$	$\log q_{oil}(t)$	$\log t$	$\log t \times \log q_{oil}(t)$	$(\log t)^2$
		$\Sigma \log q_{oil}(t)$	$\Sigma \log t$	$\Sigma \log t \times \log q_{oil}(t)$	$\Sigma(\log t)^2$

Determining coefficients a, b for the formula (7.1) can calculate the theoretical value of oil and comparing the theoretical and actual production is set convergence results (Fig. 7.1).

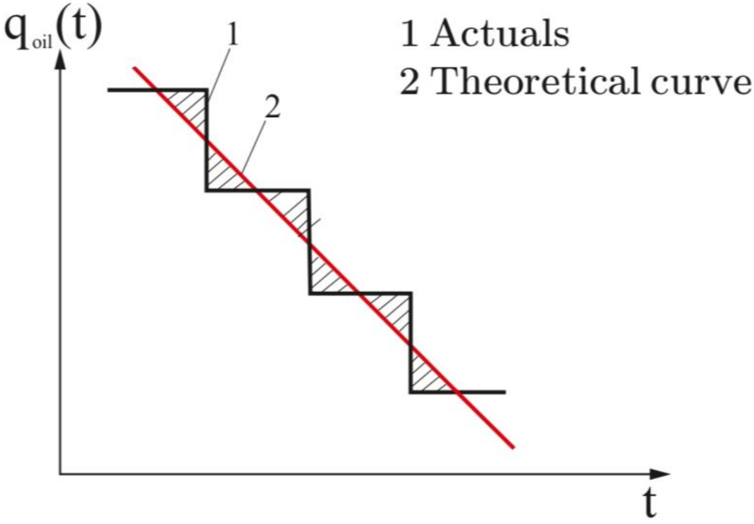

Figure 7.1 – Actual and theoretical curves

The degree of the precision composite equation is judged by a correlation coefficient, which is determined by the formula

$$r = \frac{\sum(\log t \cdot \log q(t))/n - \log t_{aver} \cdot \log q(t)_{aver}}{\sigma_t \cdot \sigma_{q_{oil}(t)}}, \qquad (7.3)$$

where σ_t and $\sigma_{q_{oil}(t)}$ - mean-square deviation

$$\sigma_t = \sqrt{\frac{\sum(\log t - \log t_{aver})^2}{n}}, \qquad (7.4)$$

$$\sigma_{q_{oil}(t)} = \sqrt{\frac{\sum(\log q(t) - \log q(t)_{aver})^2}{n}}, \qquad (7.5)$$

where $\log t_{aver}$ and $\log q(t)_{aver}$ - the arithmetic mean of all values of logarithms t and $q_{oil}(t)$.

The correlation coefficient ranges from -1 to +1. The closer the correlation coefficient to the unit, the more accurate theoretical formula corresponds to the actual flow rate change over time.

For downward curves correlation coefficient is (0 - -1), for upward curves - (0 - +1).

If r = 1, the correlation is converted to exact a relationship and if r = 0, the correlation between the studied parameters do not exist. It is believed that by convergence r = 0,5 results are satisfactory, with r = 0,7 - good for r > 0,7 - excellent.

From the formula (7.3) that the larger n, the greater the correlation coefficient.

To carry out the forecast for the worked well-day can be no more than 1/3 of the years under consideration (years of development).

7.2 Forecasting oil production under characteristics water-oil displacement

Characteristic water-oil displacement is called the relationship between the accumulated oil production and accumulated fluid production. Characteristics displacement reflects the actual process of extracting oil from the depths and the associated flooding dynamics of production or development mode heterogeneity of strata displacement of oil by water. Displacement characteristics allow determining the efficiency of extraction of oil in the flooding. In practice, the displacement characteristics are used to assess the effectiveness of measures designed to improve the system design. Displacement characteristics can be divided into two types: *integral and differential*.

There are many different characteristics water-oil displacement:

$$Q_{fl}/Q_{oil}=a+bQ_w; \qquad (7.6)$$

$$Q_{oil} = a + {}^{b}\!/_{Q_{fl}}; \qquad (7.7)$$

$$Q_{oil} = a + {}^{b}\!/_{\sqrt{Q_{fl}}}; \qquad (7.8)$$

$$Q_{oil}=a+bq_{oil}/q_w; \qquad (7.9)$$

$$Q_{oil}=a+b\cdot lnQ_{fl}; \qquad (7.10)$$

$$Q_{oil}=a+b\cdot lnQ_w; \qquad (7.11)$$

$$Q_w=a+bln(q_w/q_{oil}); \qquad (7.12)$$

where Q_{oil} , Q_{fl} , Q_w - accumulated oil, fluid and water production; q_{oil} , q_w - year production oil and water; *a*, *b* - statistical coefficients.

Integral characteristics water-oil displacement (7.6), (7.7) and (7.10) are the most simple and convenient, those in the processing of data to determine the effectiveness of hydrodynamic action. Characteristics of water-oil displacement (7.9), and (7.12) are differential. They include the following values: current production, water cut.

The coefficients *a* and *b* are determined by statistical data processing from the system of equations

$$\begin{cases} \sum y = na + b\sum x, \\ \sum xy = a\sum x + b\sum x^2. \end{cases} \qquad (7.13)$$

Where

$$b = \frac{\sum y \sum x - n\sum xy}{\left(\sum x\right)^2 - n\sum y^2};$$

$$a = \frac{\sum xy - b\sum x^2}{\sum x}.$$

In this case, the prediction of the expected oil production will hold through arithmetical selection dependence, corresponding to actual dependence accumulated oil production from an accumulated fluid. The initial input data are:

Years	Accumulated oil production, ths. tons	Accumulated liquid production, ths. tons

Prediction for extracting characteristics repression carried out as follows. Pick formula by which we carry out forecasting (this is a formula in which the highest correlation coefficient in absolute value). Determine the amount of extracted liquids annually in recent years (for example, ten). Determine the average fluid production over the years. Then add the final production accumulated fluid (produced last year) and the average fluid production in the coming years. And according to the established formula determines the estimated accumulated oil.

In determining the accumulated oil and liquids can be found accumulated water production, years production of oil, fluid and water, and the water cut to determine the growth of production for years.

Thus, forecasting production is carried out in three stages:

1) pre-processing statistical series;

2) the choice of form curve that describes the change in flow rate over time;

3) the calculation of the unknown coefficients *a* and *b* in the equation of the curve and the actual prediction.

§8 METHODS FOR INCREASING OIL RECOVERY

8.1 Classification of methods for increasing oil recovery

The effectiveness of oil recovery from oil-bearing formations using modern industrial methods is considered unsatisfactory in all oil producing countries, while the consumption of petroleum products is growing worldwide every year.

Average ultimate oil recovery in different countries and regions is ranging from 25 to 40% and makes, for example, in Latin America and Southeast Asia 24-27%, in Iran 16-17%, in the USA, Canada and Saudi Arabia 33-37%, in Russia up to 40%.
It means, that ***the residual or non-recoverable oil runs up to 55-75% of the initial geological oil resources*** (Fig**. 8**.1).

Therefore application of Enhances Oil Recovery (EOR) technologies, which can considerably increase recovery in already developed oil reservoirs.

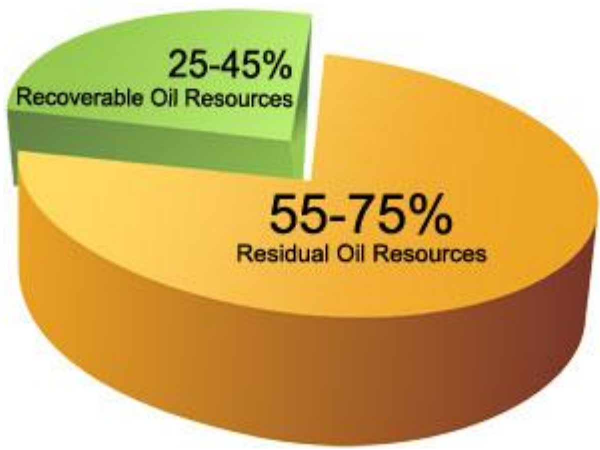

Figure 8.1 - World recoverable and residual oil resources

Interest towards Enhanced Oil Recovery methods is increasing every year all over the world and researches aimed at finding scientific approach to choosing the most effective EOR are developing rapidly.

In order to improve the economic efficiency of oil field development and to reduce direct capital investments the entire period of oil field development is usually divided into three main stages.

At the first stage of oil production (**primary production**) the natural energy of an oil field is used as much as possible. This energy is mostly the elastic energy, the energy of the dissolved gas, the energy of the gas cap and the potential energy of gravitational forces (Fig. 8.2).

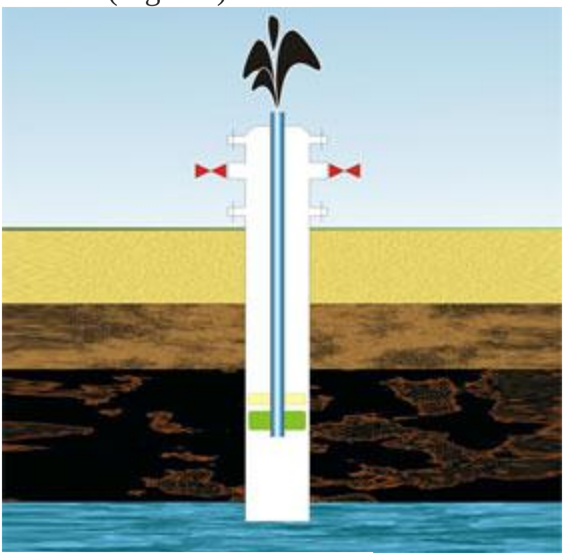

Figure 8.2 - Primary production

At the second stage methods to maintain reservoir pressure by injecting water or gas are implemented. These methods were called methods of **secondary production** (Fig. **8**.3).

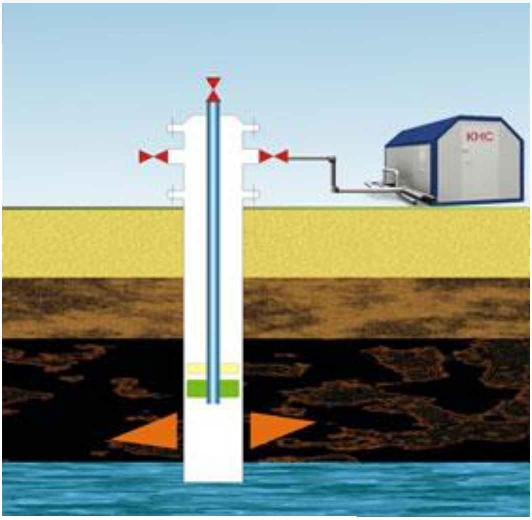

Figure 8.3 - Water/gas injection

<u>At the third stage</u> enhanced oil recovery (EOR) methods are used to improve the production efficiency. This stage is generally associated with so called **tertiary production** (Fig. 8.4).

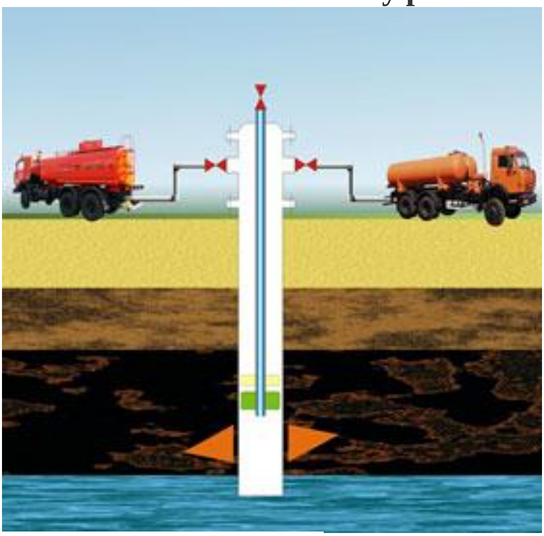

Figure 8.4 - EOR production

The actual distribution of residual oil requires that EOR methods first of all effectively influence oil in flooded and gassy areas as well as by-passed zones not covered by the current system of oil production.

It is absolutely obvious that with such a wide variety of the residual oil saturation conditions as well as under large differences in the physical properties of oil, water, gas and permeability of oil-saturated zones there cannot one universal method for enhanced oil recovery.

All the known EOR methods are generally classified as follows:

1. Thermal EOR

- Steam treatment;
- In situ combustion;
- Hot water flooding;
- Cyclic steam treatment.

2. Gas EOR

- Air injection;
- Light hydrocarbons injection;
- Carbon dioxide injection;
- Nitrogen, flue and other gases injection.

3. Chemical EOR

- Surfactant flooding (including foam);
- Polymer displacement;
- Alkaline displacement;
- Acid displacement;
- Chemical reagents displacement (including micellar-polymer flood, etc.);
- Microbiological treatment.

4. Hydrodynamic EOR

- Integrated displacement technologies;
- Development of by-passed oil reserves;
- Barrier flooding;
- Non-stationary (cyclical) flooding;

• Accelerated production;
• Stepwise-Thermal flooding.

5. Combined EOR

In most cases combined EOR methods are implemented. These are different combinations of hydrodynamic and thermal, hydrodynamic and physicochemical, thermal and physicochemical and other methods.

6. There are also some locally applied methods which are usually attributed to a special group called **Oil Production Intensification methods**. It would not be quite correct to associate these methods with EOR methods since while increasing for some period of time the current oil production (recovery) they do not usually increase the final recovery rate as EOR methods do.

All the methods mentioned above are characterized by varying potential of enhanced oil recovery.

For example, Russian oil recovery index using thermal methods is about 15-30%, gas methods is around 5-15%, chemical methods is about 25-35%, physical methods is around 9-12%, hydrodynamic methods make 7-15% (Fig. 8.5).

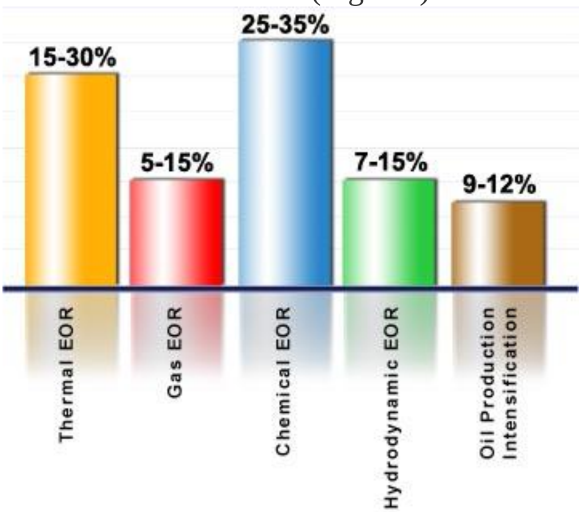

Figure 8.5 - Carability of different EOR methods

Classification of methods for increasing oil recovery has the form (Fig. 8.6).

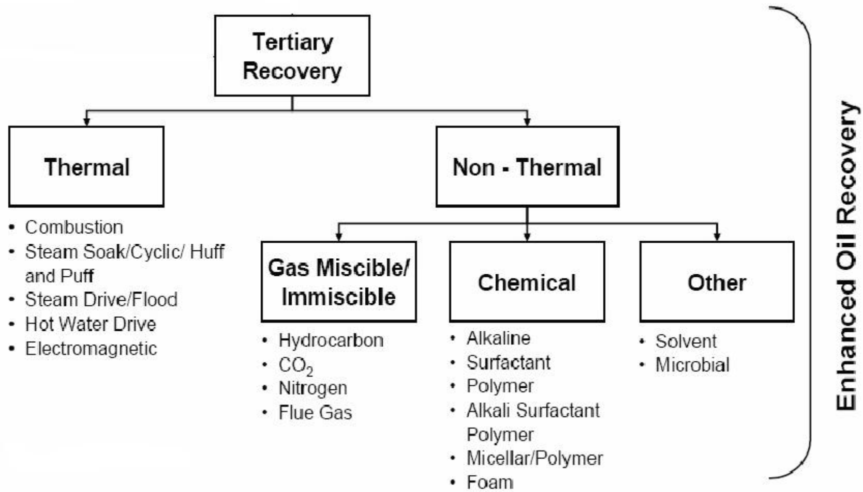

Figure 8.6 - Classification of methods for increasing oil recovery

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