Textbook

Enhanced Oil Recovery Methods

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Preface

The textbook is devoted to one of the most important problems of oil field development - enhanced oil recovery methods.

This problem is getting more actual with time as there is observed a clear tendency of an increment of recoverable hydrocarbon reserves due to the predominant discovery of oil reserves in reservoirs of complex composition and structure.

The development of such reservoirs by a traditional method (natural drives, waterflooding) is frequently not very efficient. The alternative is application of active recovery methods (RM), in other words, enhanced oil recovery methods (EORM). Nowadays over two tens of stimulation methods as well as based on them tens of injection technologies of various working agents into the formation have been developed and used.

The recoverable reserves of natural hydrocarbons considerably increase when the most suitable and efficient EORM for each specific formation are used. RMs are highly technological methods as compared with pool development by natural (depletion) drives and waterflooding.

The selection of the proper RM for natural hydrocarbon reservoir is to increase recoverable reserves (thus, to incrementl oil recovery) and to decrease technological and financial risk in development.

The textbook consists of an introduction, six parts, conclusion and an appendix.

Part I is devoted to a brief description of the current status and the prospecs for application of recovery methods.

Part II gives the description of the most developed and effective oil recovery methods. The presented classes of methods include hydrodynamic, thermal, physico-chemical, gas and microbiological ones.

Within each class the mechanisms of oil displacement characteristic of the basic recovery methods are described in detail.

Part III is concerned with the description of the main applicability criteria. The applicability criteria consist of the following geologo-physical parameters: rock, reservoir, formation oil, water, gas and other agents; petrographo-mineralogical rock composition.

Part IV covers the aspects of technological and economic efficiency and application of the main recovery methods based on the data obtained from experimental - industrial tests and commercial realisation of these methods.

Part V is dedicated to the description of the original methods of applicability estimation of recovery methods for real geological formations. This methods includes expert data and a fuzzy set theory.

A scientific research-methodological experience which served as a basis for competing the present textbook has been mainly gained within the activities in the Russian State University of Oil and Gas named after Gubkin and the Oil and Gas Research Institute (OGRI) of the Russian Academy of Sciences.

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INTRODUCTION

The selection of a recovery method (RM) under the design of oil field development is a complicated and important stage. The overwhelming majority of recovery methods are more complicated processes as compared with a natural drive. A substantiated selection of a recovery method enables to reduce considerably technological and economic risks in oil field development using RM, as well as to garantee a high profitability when carrying out the recommended reservoir engineering.

Any stimulations of the oil predicting formation are mainly reduced to maintenance or increase of oil mobility. Oil mobility is maintained by means of water injection into the producing formation thus keeping up original thermodynamic reservoir conditions: reservoir pressure and temperature. The increased oil mobility may be maintained due to;

- decreasing oil viscosity;
- increasing porous medium permeability of the producing formation;
- increasing the displacing ability of the working agent;
- washing out ability of the working agent (water and others).

The selection of the oil recovery method is preceded by the stage of detailed studies of geological structure of the producing formation, petrographo-mineralogical composition, structure and petrophysical properties rocks composing the formation, geochemical conditions and characteristics of the fluids saturating the formation.

A geological model of an oil reservoir is a heterogeneous, anisotropic, three - dimensional formation constructed on the basis of processing geophysical and field geological information. This information is obtained from a host of discrete points (exploratory wells). There are special computer programs which process the geologo-physical well information and compile maps. Heterogeneity of reservoir structure stipulates a known fuzzy logic of a real distribution of geologo-physical parameters in the areas between the wells, because a confidence interval of well geophysical research amounts at best to about 0,5 m and the seismic profiling is equal to about 5-10 m and is extremely expensive.

The basic part of a geological model is a reservoir making up the producing formation. Formation characteristics and their variation in the reservoir volume are mainly the major parameters in selecting RM for a pool. Most of researchers consider that the reservoir properties of producing formations do not practically change within all the period of pool development. Recent studies show that in reality any external pool effect influences all its components including the rocks of producing formations which undergo different alterations, as well as changes of physical properties.

Before oil and gas pool is exposed by the wells it is a balanced metaslable thermodynamic system. Well drilling-in breaks this balance. First of all the movable gases are removed, thus reducing the formation pressure and this further results in chemical balance disturbance of fluids saturating the formation, and in their composition change. The rock making up the formation will undergo some superimposed stress due to reduced formation pressure. All these disturbances can't but influence the lithological reservoir characteristics and hence the well production rate, and, finally, a complete oil recovery, i.e., an oil recovery factor.

1. Current status and prospects of application of recovery methods

One of the main tasks of oil field development is enhanced oil recovery. A considerable increment in oil recovery resulting from the application of recovery methods as compared with the traditional development methods is mainly achieved in high-viscosity oil formations, water-cut layers and low-permeable reservoirs. World oil reserves amount to about 600×10^9 t. RM application will average oil recovery by 5÷10 %. This is correspondingly equal to $(30\div60)\times10^9$ t increment of recoverable oil reserves.

Great contribution in creating, development and modelling of RMs has been made by: Abasov M.T., Avdonin M.A., Alishayev M.T., Amelin I.D., Babalyan G.A., Baibakov N.K., Basniev K.S., Bogdanov I.I., Bokserman A.A., Buchenkov L.N., Charygin A.B., Chekalin A.N., Chekalyuk A.B., Chen-Sin A.P., Dubrova I.N., Entov V.M., Gavura V.E., Garushev A.P., Gimatudinov Sh. K., Gorbunov A.P., Ibragimov G.Z., Ivanova M.M., Ivanov V.A., Khisamutdinov N.E., Levi B.I., Malofeev G.E., Mamedov Y.T., Markhasin E.L., Mukharsky E.D., Namiot A.Y., Nigmatulin R.E., Oganov K.A., Onoprinko A.V., Rakovsky N.L., Rozhdestvensky V.A., Rubinstein L.I., Stepanov V.P., Strizhov I.N., Surgutchev M.L., Sheinman A.B., Shelkachev V.N., Tarasov A.G., Vazheevski A.G., Yakuba S.I., Zhdanov S.A., Zheltov Y.V., Aziz K., Balint V.B.

According to the generally accepted classification natural hydrocarbons are subdivided into the following classes:

- gas;
- condensate;
- oil;
- bitumen.

In the manual consideration is given to the selection problems of recovery methods only for oil fields

The oils of these fields are distinguished by density and viscosity values. Generally, natural hydrocarbons with the density of 820-1030 Kg/m^3 and the viscosity of 0.01-10 000 mPa×c should be related to oils. The rate of oil recovery factor constantly changes depending on the development conditions, well spacing ratio and formation pressure P. The methods of enhanced oil recovery are very complicated and expensive, rather poorly studied, their efficiency in real conditions being determined by many geophysical and technological factors. Expenses connected with the creation of the capacities for production of 1 t of oil by these methods are 5-10 times higher than in a conventional waterflooding. Over 80 % of all the oil pools are being developed by reservoir pressure maintenance using water injection into the producing formation, but in these cases oil recovery factor seldom exceeds 50 %.

One of the most widespread RM classifications is the one based on a physical characteristic of the displacing agent. There are distinguished the following basic RM types:
- hydrodynamic;
- thermal;
- physico-chemical;
- gas;
- microbiologic.

'he main RM types include the following enhanced oil recovery methods (see table 1.1.)

Table 1.1. Classification of enhanced oil recovery methods

1. Hydrodynamic
    1.1. Waterflooding
2. Thermal
    2.1. Steam injection
    2.2. Hot water injection
    2.3. In-situ combustion
3. Physico-chemical
    3.1 Surfactant water solution injection
    3.2. Polymer water solution injection
    3.3. Alkali water solution injection
    3.4. Miceller flooding injection
    3.5. Miceller-polymer injection
    3.6. Sulphur acid water solution injection
    3.7 Alcohol water solution injection
    3.8. Carbonated water flooding
4. Gas
    4.1. Nitrogen injection
    4.2. CO_2 injection
    4.3. High pressure gas injection
    4.4. Hydrocarbon solvent injection
    4.5. Enriched gas injection
5. Microbiologic
    5.1. Biosurfactant injection
    5.2. Biopolymer injection

5.3. Injection of micro-organisms with food cycling
5.4. Microbe (melass) flooding
5.5. Activization of natural microflora.

By the origin of forces the enhanced oil recovery methods can be subdivided into thermal, hydrodynamic, physico-chemical, microbiologic and acoustic.

Thermal methods are intended to increase oil mobility, mainly due to its viscosity, by injecting hot water and steam into the formation as well as by creating in-situ combustion source. Moreover, in the better case along with decreasing oil viscosity, its recovery factor increases because of letter oil displacement by the products of its distillation. The purpose of physicochemical recovery methods is either to increase the competence of water flow (by injecting surfactants, carbon dioxide fringes, miceller solution, liquefied gases, concentrated sulphuric acid, alkali solutions or bioreagents) or to improve the displacing water properties by injecting polymers or inertia gases, foams emulsions) or to increase oil mobility by reciprocal oil and gas dissolution when gases are injected.

At present only 10-11 methods have got industrial and experimental - industrial application out of dozens of perspective recovery methods. They are: injection of polymer water solution, surfactants, alkali, sulphuric acid, miceller solution, hydrocarbon gases, carbon dioxide, nitrogen and hot water, as well as steam - thermal stimulation and in-situ combustion.

Oil pool development by an active formation stimulation means injection of an active agent displacing oil from porous media. At present a lot of working agents such as water, acid, various gases, physico-chemical substances and others are known. Water is the most accessible, cheap and widespread agent.

The oil stimulation method connected with water injection became known as a waterflooding method. A considerable amount of oil, up to 95 % of all the oil in Russia and about 50% in the USA, is produced by this method.

Most of the oil produced in the world by the enhanced recovery methods comes to 73 % under thermal methods, 36 % under gas methods and only 4 % under physico-chemical methods. In Russia the ratio of applying recovery methods is quite different: about 50% of oil produced by various enhanced recovery methods come to thermal methods, 44 % - to physico-chemical methods and 6 % - to gas methods.

Table 1.2. Additional oil recovery due to introduction of EOR methods (mln.t/%).

	RM	Steam	Hot water	Surfactants	CO_2	Hydrocarbon gases	Polymer flooding
CIS	10/100	2.1/21	1.4/14	1.1/11	-	-	-
USA	32.3/100	21.8/68	-	-	4.7/4.6	2.7/8.4	-
Canada	7.48/100	-	-	-	-	6.23/83	0.84/11.2

The most perspective technologies for thermal methods are steam - thermal stimulation and hot water injection which promote the production of 58-65 % of the total oil recovery using thermal recovery methods (see Table 1.2).

As to gas methods, CO_2 and hydrocarbon injection methods which enable to increase the oil recovery factor of the water-encroached formations up to 18 % are most widely used. However the application of these recovery methods is restrained by high cost of gases amounting to 50 - 70 % of the total cost of technology where they are used. In Russia these methods are not so widely used due to the lack of permanent sources of CO_2 production and reliable transport means for its transportation and injection.

One of the physico-chemical methods polymer flooding is used commercially. The development of other the physico-chemical methods is restrained due to high cost of chemical agents and unequal results of experimental - industrial tests. However, due to the technological improvement of physico-chemical methods oil recovery may amount to about 40 % of the total recovery achieved by applying all the RMs (Fig. 1.1)

Microbiologic methods which are at the stage of laboratory studies are most perspective RMs.

2. The basic mechanisms of oil displacement under different methods

Let's consider some physico-chemical processes occurring in the formation under different active stimulation methods. When different RMs are used, the oil displacement mechanism is characterised by a complex combination of various hydrodynamic and physico-chemical processes possessing specific characteristics under geophysical conditions. In addition, oil field development breaks a balanced metastable thermodynamic system which had existed in the formation before it was exposed by wells.

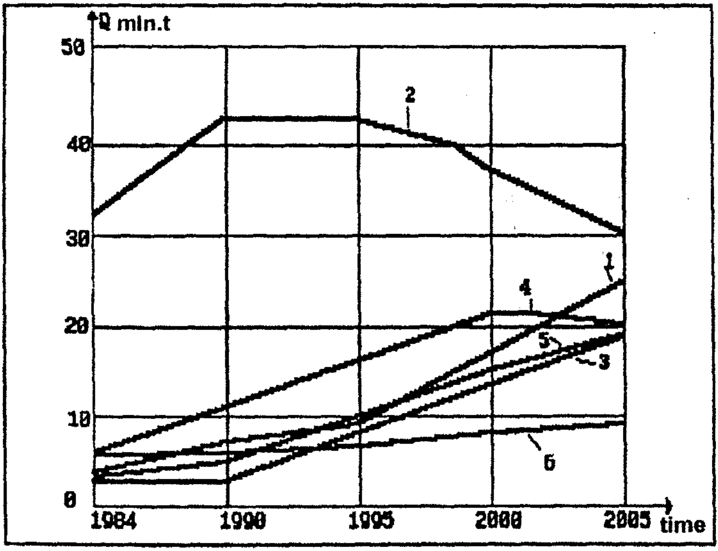

Fig. 1.1. Total oil recovery obtained at the expense of enhanced oil recovery methods
1-2 – thermal methods (1 – CIS, 2 – USA);
3-4 – physico-chemical methods (3 – CIS, 4 – USA);
5-6 – gas methods (5 – CIS, 6 – USA).

By character the disturbances may be subdivided into the results of action of mechanical, physico-chemical and chemical processes.

The first group includes the changes of filter discrimination bottom-hole reservoirs due to colmatage of pore space by clay drilling-mud as a result of mud filtrate inflow into the formation and accumulation of the mechanical suspended matter in pore space from the injected water. This category of mechanical reservoir changes should include rock failure under the hydraulic force of jet of producing liquid, sand withdrawal and sand bridging. Rock failure is greatly influenced by such field operations as hydroswabbing, vibration effect, abrasive jetting and hydrofracturing. One of the reasons decreasing well productivity under formation development is rock deformation when reservoir pressure is reduced.

The changes influenced by physico-chemical processes include transformations connected with drilling mud swelling when formation waters are replaced by the drilling mud filtrate or by waters injected into the formation due to formation pressure maintenance. Drilling muds have stratified structure which enables water intrusion into interpacket space and its maintenance due to adsorbtion and other forces thus causing expansion and swelling of the lattice. Change of pore volume in a clay reservoir when the composition of filtrating waters changes occurs because of the fact that the share of hydrate pore space changes.

Under field development the disturbance of a chemical equilibrium of formation fluids often takes place causing precipitation of nonorganic salt in the equipment and probably in the pore space of the producing formation thus finally reducing well production rate and resulting in considerable oil under recovery.

2.1. Hydrodynamic recovery method

2.1.1. Waterflooding

Waterflooding is one of the most widely used recovery methods when the process of water displacement takes place simultaneously with formation pressure maintenance. Thus there is another term for the method - formation pressure maintenance. Water is used as a working agent because of its displacement, wide accessibility and cheapness. Displacement bank is formed in front of the displacement front and the undisplaced oil and water remain behind the front (see fig. 2.1). Water application provides rather a high

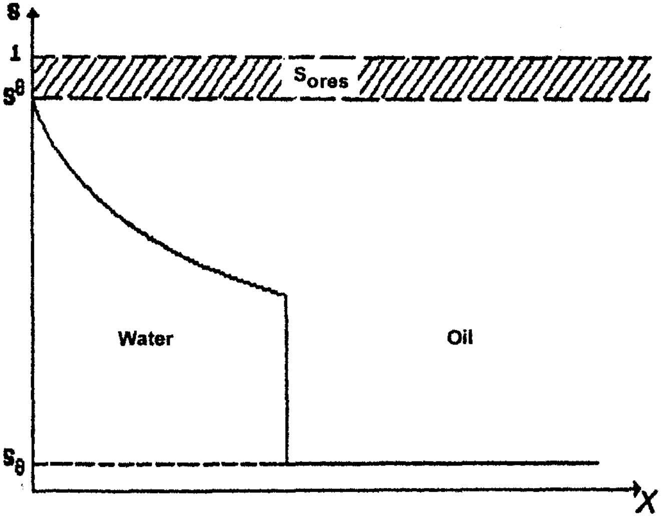

Fig.2.1. Scheme of water displacement:
S^0 – maximum watersaturation;
S_0 – connate water;
S_{ores} – residual watersaturation.

stability of the displacement front due to the fact that oil density and viscosity are close to the corresponding characteristics of most of oils and because high inter-facial tension doesn't promote viscous fingering. Residual oil saturation varies within a wide range from 0.05 to 0.90 fractions of units. This value mainly depends on the ratio of oil and water mobilities and on the heterogeneity of filtration volumetric properties of oil reservoir (porosity, permeability, etc.). Oil recovery factor (η) in flooding is determined as the product of reservoir sweep efficiency (k_{sw}) by displacement factor (k_{dis}) (determined in lab tests of the core):

$$\eta = K_{dis} \times K_{sw}$$

The waterflooding efficiency is also influenced by the ratio of water and oil mobilities:

$$M = \lambda_B / \lambda_H = 1$$

Due to lower water viscosity as compared with oil viscosity its mobility is higher than that of oil. Fig. 2.2 presents the dependence of oil recovery on the volume of injected water (in fractions of V_{por}) for various M values.

Flooding is mainly used in development of porous reservoirs. In fractured reservoirs flooding is efficient in case of hydrophilic rocks and homogeneous fracture system. In this case water quickly breaks through high permeability fractures and a long period of high water encroachment exploitation (80÷90 %) is observed. Capillary forces cause capillary imbibition: water is soaked by rock skeleton and oil is displaced.

In fractured reservoirs with hydrophobic rock water the flooding is not efficient, i.e. oil produced only from the fracture system volume of fractures is small as compared with the volume of pore, so oil recovery factor is low.

We may distinguish the following modifications of the waterflooding method:

- continuous water injection,
- cyclic water injection,
- cross-filtration.

Cyclic water flooding is mainly intended for increasing reservoir sweep. Cross-filtration is performed if injection is replaced by the fluid withdrawal in the injection well and the withdrawal is replaced by water injection in the producing well. This water flooding modification as well increases stimulation reservoir sweep.

In addition the following water-flooding systems are applied:

- edge flooding;
- marginal flooding;

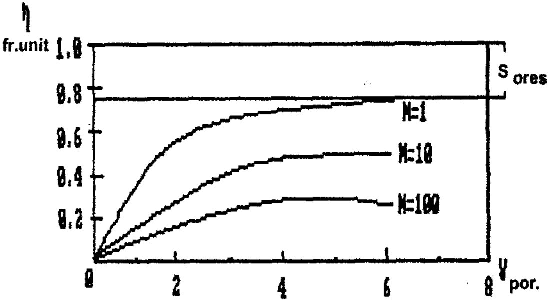

Fig. 2.2. Oil recovery dependence η on the volume of injected water (in units of porous volume V_{por} for various values of mobility M)
Here $S_{ores} = 0.25$ is residual oil saturation.

- peripheral flooding;
- pattern flooding;
- local flooding.

You may find more detailed information about advantages and disadvantages of the above water-flooding systems and technologies in special literature [2, 4, 9, 14, 32, 33, 60]. The most visible changes of formation oil properties are observed in well drained zones under a long exploitation at high water-oil ratio (WOR).

Thus, first of all, we'll consider the changes in the volume of clay minerals which are very sensitive indicators of the thermobaric and geochemical changes occurring in producing formations when pressure, temperature or intrusion of water with new physico-chemical properties change. It's related to the particular structure of clay minerals, their stratified structure. The bond between the neighboring structure elements is broken by the intrusion into the interpacked space of water which penetrates and retains here under adsorption, osmotic and capillary forces causing expansion and swelling of the lattice.

The adsorption activity of clay minerals depends on the active surface of minerals which reaches 500-800 m^2/g in montmorillonites and sharply decreases in other minerals and is determined by the degree of isomorphous replacement, dispersion, etc. By the amount of water susceptibility the clay minerals are arranged (in the decreasing order) in the following way - montmorillonite, commingled formations of the hydromica family - montmorillonite, chloride, hydromica, kaolinte. The swelling process is influenced by the medium anion character and mineral cations, medium hydrogen ions concentration, fluid polarization and thermodynamic conditions of the process. Exchanging cations of the mineral and the anions of the medium may be arranged by the decreased degree of their influence on swelling. The arrangement may be presented for cations: Li>Na>K>Mg>Cr>Ba>Al>Fe, for anions:
CNs>I>Br>No>Clo>Cl
The main determining factor of clay swelling is cation valency. Monovalent cations promote clay dispersion increasing their initial volume in the presence of water to tenfold. Monovalent cations neutralize the adsorption centres and are favourable for water penetration between the particles of clay minerals. Saturating the clay particles, the polyvalent cations promote their aggregation preventing water inflow between them [61, 72].

High dispersion, large specific surface of clay particles provide better exchanges reactions and it results in desagregation and tearing off the clay flakes, the process of selfcolmage taking place. However a considerable recovery of permeability when fresh water is replaced by mineralized water shows that permeability change is due to change of the film thickness of bound water which depends on mineralization and surface energy of the mineral skeleton. Changing of pore volume in clay reservoir at changing of filtrating waters due to changes of pore space share, the volume occupied by a hydrate layer may be estimated by S.D. Pirsons formula $K_l/K_g(1-\alpha)^{-3}$, where K_l - rock permeability to the given fluid; K_g - permeability of the same rock to gas; α - share of pore volume occupied by a hydrate layer.

Thus, when flooding takes place for the purpose of maintaining reservoir pressure, one should take into account the character and mineralization of the injected and formation water. Their noncompatibility decreases rock permeability and, as a result, reduces well production rate [36, 50]. In oil reservoir development a disturbance of chemical balance of formation waters is observed. It results in precipitation of nonorganic salts in porous space of producing formation rocks finally reducing well production rate, breaking well behavior and causing a considerable oil under recovery. Very often in reservoir development there is observed precipitation of carbonate and sulfate salts resulting from the disturbance of carbonate or sulfate system equilibrium and is stipulated either by mixing of noncompatible formation and injected waters or by changing the fluid phase state under decreased reservoir pressure. According to K.B. Ashirov's data, in waterflooding of a number of producing deposits of the Volgoural region, carbonate precipitation in the rocks of the marginal deposit is zone observed. As a result those deposits may become sealed and waterflooding may be very ineffective in them.

The main source of salt liberation is water produced together with oil. Its composition changes in the process of reservoir development causing a variety of salt compositions and their change in time. The key direction of salt accumulation study under oil field development is a search for means of fighting with already formed sediments and measures for their prevention.

In conclusion we would like to cite the data of K.B. Ashirov and his co-authors [3] concerning the change of the producing ability of wells tapping the carbonate formation A4 of the Bashkirian stage of the Middle Carbonian at the Yakushinsk field before and after gypsum fallout. At 30-50 % water encroachment the production rate of well 121 came to 80 and well 122-70 t/day. As a result of gypsum fallout, the well production rate reduced correspondingly to 13 t/day in well 121 and to 6 t/day in well 122 at 20 and 30 % water encroachment.

A massive reservoir is hydrodynamically isolated from the formation water-injection system. Fracturing is widely developed in the near top area of formation.

After the beginning of water injection into the formation, its break inrush through the central row into the development wells located at the distance of 320-360 m occurred 1-2 months later, the initial rate of water encroachment being 8-10 % a month. In a fractured zone there is observed a sharp growth of water encroachment which reduced at 30-40 % due to selective gypsum fallout in well permeable areas resulting in leveling the heterogeneity of reservoir by permeability. It should be noted that along with negative effect of gypsum fallout its selective precipitation in fractured carbonate formation A4 has a positive effect on oil recovery increasing its prevention of progressive well stream watering. To tell the truth, ultimately this process in the given case proved to be negative and considerably complicated the oil recovery.

2.1.2. Oil reservoir development by horizontal wells

Reservoir development by horizontal wells has a number of advantages over the development by vertical wells, especially of small profitable fields.

Reservoir development by horizontal wells is accompanied by:

- increasing the drainage area;
- increasing the efficiency sweep factor;
- increasing well productivity (injectivity);
- decreasing possibilities of viscous fingering and coning for water and steam;
- lowering differential pressure at the same withdrawal rates, resulting in decreased water and gas production;
- extracting the largest oil volume in short periods in fractured reservoirs when drilling perpendicular to the well system orientation;
- increasing oil recovery 2-3 times in low - permeability thin oil formations with gas cap;
- increasing withdrawal of recoverable reserves in high permeability formations.

Technological and economic efficiency of reservoir development by horizontal wells depends on:

- the activity of water and gas drives;
- oil viscosity;
- ratio of water and oil mobilities;
- relative oil, water and gas permeabilities;
- fracturing (in direction of fractures);
- formation parting (and availability of clay partings);
- absolute permeability both vertical and horizontal.

The main merit of horizontal wells is a high production rate. It must be high to justify the cost of a horizontal well. A horizontal well is about 1.3÷1.7 times more expensive than a vertical one. The disadvantages of oil field development by horizontal wells are:

- high cost of development and exploitation;
- complications in performing logging perforation and well stimulation;
- low reservoir vertical sweep factor at high parting.

There exist technologies for such kinds of complications. That is drilling of multi-bore horizontal wells; hydraulic fracturing of formation in horizontal wells, increasing the length of a liner. If the length of the liner is about half of the distance between injection and producing well, the areal sweep efficiency factor tends to 1.

In fractured reservoir with high conductivity of fractures there are not expected obvious advantages of horizontal wells over vertical ones. Horizontal wells provide high oil recovery in case of realization of row well pattern as well as in case of marginal waterflooding. It should be noted that the number of oil field development by waterflooding with horizontal wells is not great.

2.2. Thermal recovery methods

One of the most widely spread EOR is thermal recovery methods for the high oil viscosity reservoirs which causes a considerable increase in oil mobility. In addition the increased temperature influences some minerals making up the rock composition and transforms them. Thermal studies in mineralogy are known to include temperature ranges when decomposition of several minerals composing the reservoirs takes place: hydromicas (degradated) - 250 -300 °C, chlorites - 250-600 °C; montmorillonite - 300-700 °C; kaolinite - 500-600 °C, pyrite - 350-450 °C.

2.2.1. Hot water injection

The main mechanism of enhanced oil recovery when hot water injection method is used is connected with reduction of oil viscosity and changing the ratio of oil (λ_o) and water (λ_w) mobilities, changing of residual oil - saturation and relative permeability, decreasing capillar forces for oil which prevent oil recovery from low-permeability interlayers as well as thermal expansion of fluids (see Fig. 2.3).

Hot water injection results in a considerable increase of sweep efficiency factor both vertically (K_v) and areally (K_a) mainly due to a sharp decrease of formation oil viscosity when the temperature increases. The higher is the oil viscosity at the initial formation temperature, the more obvious this effect is. The scheme of oil displacement by hot water plug is given in Fig 2.4. In contact with not heated formation and the oil saturating it hot water becomes cool. Two zones may be separated with a steady-state motion in the formation: oil displacement by hot and cold water. Zone I is characterized by a continuous temperature increase thus resulting in changing (decrease) the residual oil saturation. Besides, temperature increase causes expansion of the reservoir and the liquid saturating it and

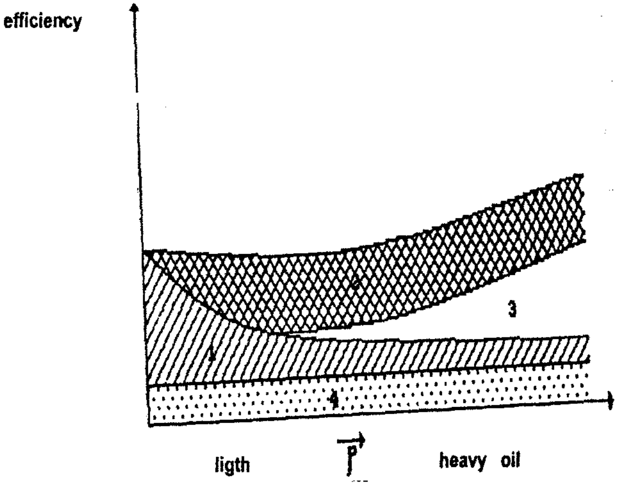

Fig. 2.3. Effect of various processes on efficiency of oil displacement by heated water without evaporation: 1- thermal expansion; 2- viscosity decrease; 3- wettability; 4 – oil-water interfacial tension.

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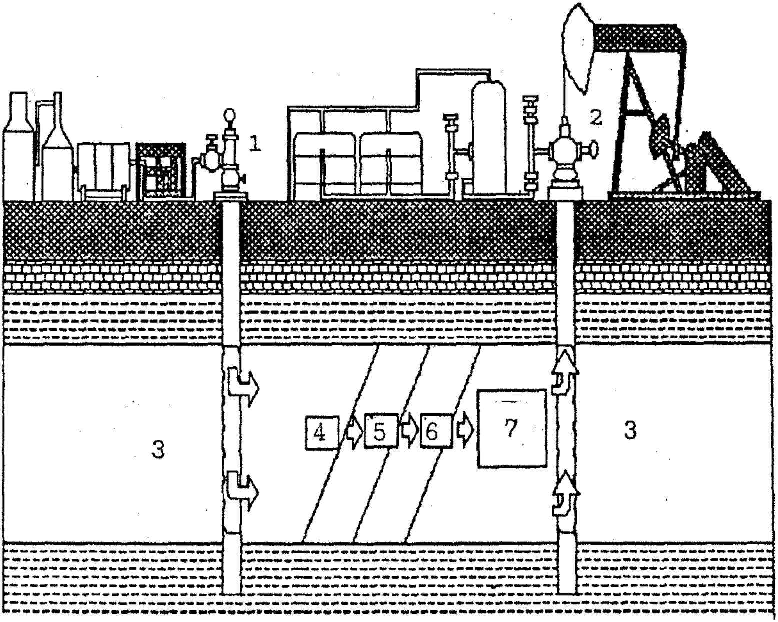

Fig. 2.4. Scheme of oil displacement by hot water plug: 1 – injection well; 2- production well; 3 – viscous oil zone; 4 – cold water zone; 5 – hot water zone, 6 – oil bank; 7 – oil and water zone close to initial reservoir temperature.

results in decrease of oil mass (under condition of constant saturation) contained in the formation. In some cases when hot water injection method is used for low-density oil displacement, the process of distillation (that is, evaporation followed by condensation of light hydrocarbon fractions) may be observed. Oil displacement by ordinary cold water with the temperature equal to the temperature of the formation occurs in zone 2. Oil displacement change takes place in the same way as in a conventional waterflooding. Zone 3 is a zone of an initial reservoir condition. Fig. 2.5 present profiles of water-saturation and temperature when oil is displaced by hot water without evaporation of light hydrocarbon fractions.

2.2.2. **Steam injection (Steam - thermal bed stimulation)**

Analysis of numerous projects with steam injection showed that the technology of continuous pumping of steam slug by cold water resulted in a considerable cooling of the formation. The latter was accompanied by formation pressure decrease and filtration of warm-up oil into this zone. The technology of cyclic steam and water injection is more efficient because of optimum and minimum warming-up of the formation in this case, as well as because of reduced intensity of steam fingers encroachment along the high - permeability sections of the formation (see Fig. 2.8). The efficiency of technology of steam injection with surfactants is connected with achieving the uniform fronts of water displacement by steam. Steam injection into the formation containing low-density oil is on the whole characterized by a lower economic efficiency.

Due to the fact that the ecological standards for air and water pollution control became more strict, one should expect a reduced application of coal and oil as fuels for water heating, and the requirement of ecological pure projects with steam utilization will be a determining one.

At steam - flooding three characteristic zones are formed (see Fig. 2.6). In zone 1 the temperature value doesn't practically change and only in zone 2 its small decrease takes place. There coexist 3 phases in this zone: water, liquid hydrocarbon mixture and gas. Oil saturation changes because of both the displacement processes and the evaporation of light oil fractions. Zone 2 is usually called condensation zone. In contact with unheated section of the formation and oil, water vapors and light hydrocarbons condensate. It increases water in place in reservoir and changes (decreases) oil viscosity. In zone 3 the processes similar to hot

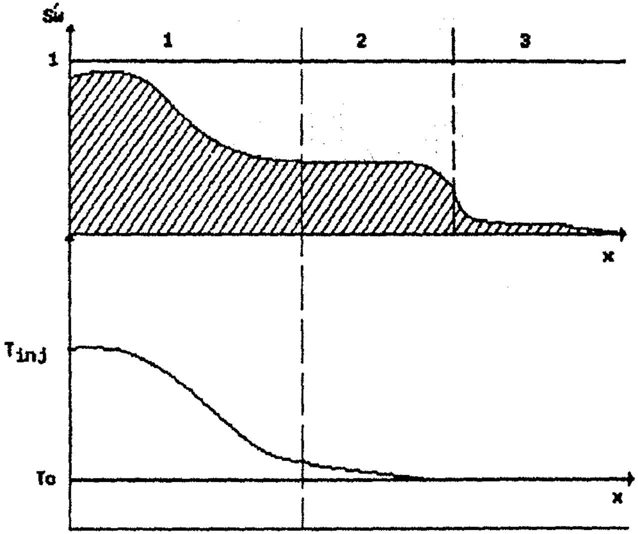

Fig. 2.5. Profiles of water saturation and temperature at hot water drive: 1- hot water drive zone; 2 – cold water drive zone.

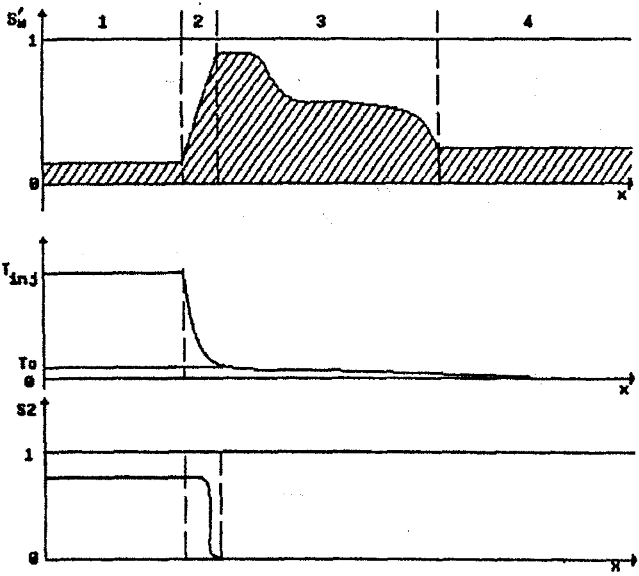

Fig. 2.6. Profile of water saturation, temperature and steam-saturation: 1 – light hydrocarbon distillation zone; 2 – condensation zone; 3 – cold water drive zone.

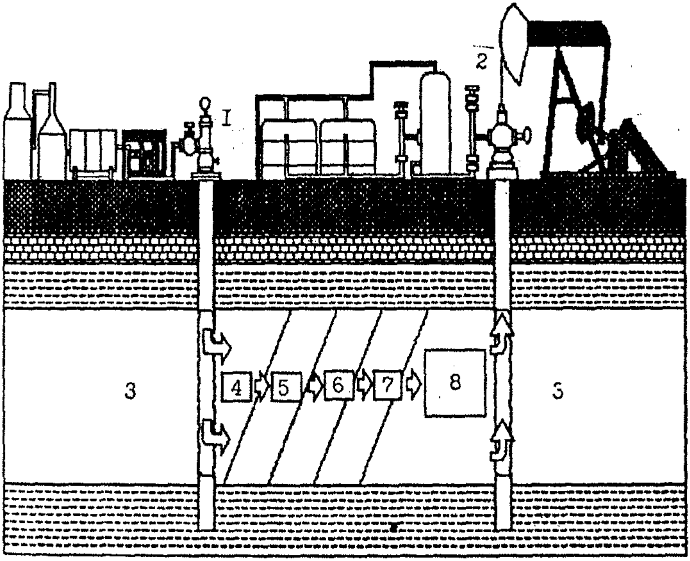

Fig. 2.7. Scheme of oil displacement by steam plug: 1- injection well; 2- production well; 3-viscous oil zone; 4-cold water zone; 5-steam zone; 6-hot water zone; 7- oil bank; 8- oil and water zone close to the initial reservoir temperature.

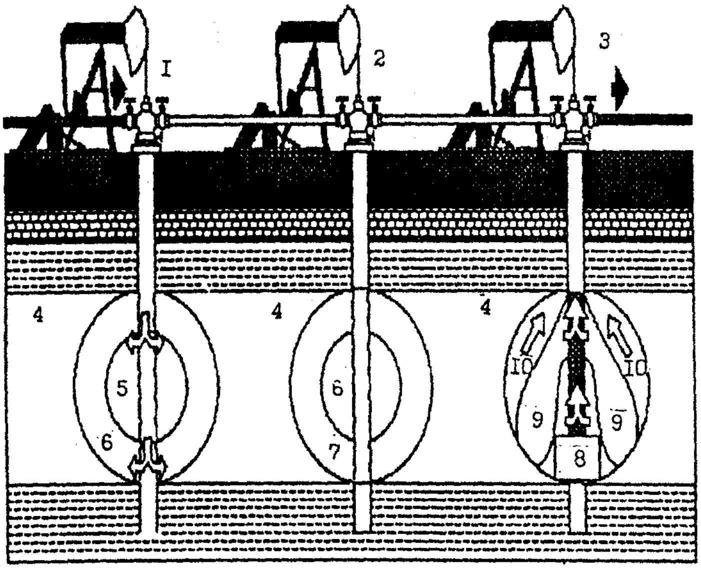

Fig. 2.8. Scheme of oil displacement at cyclic steam injection : 1- well in the injection phase; 2- well in the delay phase; 3 – well in the production phase; 4- viscous oil zone; 5- injection steam zone; 6- zone of steam and hot water condensation; 7- warm-up zone (at the expense of the condensation zone – convective heat transfer); 8- zone of washed out oil sand; 9- zone of steam condensation in residual oil; 10-zone of warm-up oil.

water injection take place though the speed of water drive in this case will be higher (at the same mass flow rate). It is due to the fact that the volume occupied by a steam mass unit is considerably more that the volume of water mass unit and the volume of zone I will constantly increase.

Fig. 2.7. gives a scheme of oil displacement by steam slug where we may single out 4 main zones.
Ultimate recovery at steam-flooding increases at the expense of decreasing reservoir oil viscosity under heat effect, changing oil and water mobility, thermal oil expansion, distillation of residual oil by steam and extraction of oil by a solvent which is formed ahead of steam front. Steam- flooding changes the mineralogical clay matter forming montmorillonite, hydromicas, kaolinite which considerably decrease filtration properties of the rocks and their hardness. When temperature increases within the first hundreds of °C, amorphous, gelatinous mass sealing the rock pores is formed together with clay minerals. On the whole when temperature increases within the first hundreds of °C, oil recovery of the producing formation increases due to higher oil mobility because of its decreased viscosity, better properties of washing away and displacing water, but, on the other hand, rock permeability reduces because of new formations of minerals, clays and some other formations which have a negative effect on rock permeability. The content and composition of autogenous - technogenous minerals considerably depend on the original rock composition and chemical properties of formation waters. In 1981 a group of researchers studied the cores of bituminous sandstones at the Cold Lake Field (Canada) which were not exposed to steam - flooding, and the cores from injection wells where steam was injected 2 years. Clastic rock was made up of siliceous, volcanic and clay rock fragments - 30 %, quartzite - 20-30 %, plagiocases - 5-10 %, potassium feldspar - 5-10 %, as well as small amounts of accessories - chert, biotite, epidote, muscovite, turmaline and pyrite. The rock cement is gel-cement of a film type made up of illite, smektite, chlorite and ceolite.

Steam injection at 250-260 °C didn't practically change the composition and ratio of clastic rock minerals and the cement suffered considerable transformations in the composition of clay matter. After stimulation only montmorillonite and analcym (zeolite) were discovered, the thickness of the cement film having increased and the pore volume having decreased. After burning the Barrem rocks of the Karazhanbas field at 250-300 °C the clastic part is bordered by a dark-frown up to black fringe of coke products of bitumen disintegration due to which porosity of samples reduced from 33-36 % to 22-26 %.

The change of mineralogical rock composition (Karazhanbas) at thermal methods (according to A.N. Petrovsky) [44] completely disappears and in addition the open porosity exceeds the initial values.

In the Karazhanbas and Uzen formations the share of a crystal phase decreases under higher temperature up to 500 °C and longer stimulation. At the same temperature kaolinite content reduces probably till its complete disintegration at long stimulation. In the Karazhanbas rocks montmorillonite completely disappears and there is observed a total decrease of the share of a crystal phase because of disintegration of clay material.

Steam-flooding in subconsolidated reservoir rocks has a negative effect on rock skeleton destruction and sand production in the well forming sand bridges. Moreover, it is known from studies made by S.A. Lobacheva et at [37] at the Binagadi-Kirmakinsk and Khorosansk fields with improved geologo-physical reservoir conditions the rate of destruction and intensity of bridging increases, the rate being the higher, the more oil viscosity reduces.

Under steam-flooding reservoir hydrobilization is possible because of melting and removing of resins and asphatenes from the walls of the pores. Steam injection results in increased rock removal to the producing wells, clay swelling in the formation.

Key technologies:

1. Steam injection into the water-bearing layer lying under petroliferous stratum.
2. Injection of steam-gas mixture.
3. Injection of steam together with solvents (liquid hydrocarbons).
4. Steam injection with various additives (foam, polymers, alkaline)
5. Cyclic steam injection.

2.2.3. In-situ combustion

This method is characterized by complicated physico-chemical processes occuring in the formation due to which oil displacement takes place as a result of various mechanisms and processes, namely, steam, hot water, combustible gases, solvents, surfactants, etc. The distribution of the temperature zones and reservoir oil saturation at in-situ combustion is shown in Fig. 2.9.

Fig. 2.10 presents various zones which are formed in oil reservoir at in-situ combustion. A burnt out zone through which the filtration of the working agents (air and water) occurs directly joins the injection well. It is followed by a combustion front where high-temperature oxidation reactions take place. To maintain the combustion process in the formation a sufficient amount of coke must be formed which depends on the content of asphaltenes, resins and heavy hydrocarbons in oil. Oil, evaporated gases, light hydrocarbons and steam filter in the steam zone. Condensation zone is formed in front of the steam zone. As the temperature decreases in this zone, condensation of steam into hot water takes place. Hot water, light hydrocarbons, combustible gases displace reservoir oil. The displaced oil is accumulated into the oil bank and moves in front of the condensation zone. Here pore space is occupied by combustible gases, displaced oil and connate water, the initial formation temperature zone being in front of this zone.

The increase of formation oil recovery at in-situ combustion takes place due to decreasing oil viscosity, oil volume expansion, oil distillation and dissolution of light hydrocarbons by carbon dioxide.

They distinguish the following technologies of In-situ combustion realization:
- in-situ dry combustion;
- in-situ wet combustion;
- in-situ extra wet combustion.

In the field of temperatures characteristic of in-situ combustion within the interval 300-375 °C there is observed decomposition of some hydromicas minerals and montmorillonite with heat absorption. Moreover endothermal decomposition predominates over exothermal at oil oxidation thus considerably preventing the process of arbitrary oil inflammation under reservoir conditions.

The presence of sulfides in the composition of some PK producing Apsheron formations explains the accelerated creation of a heat source in well 208 of «Artyemneft» which took only 30 hours, while kindling of the PK («Leninneft» OGPM) formation took only 7-10 days. Comparison of temperature change curves of the heated intervals during kindling the KS and PK formations and experimental data show a jump when KS

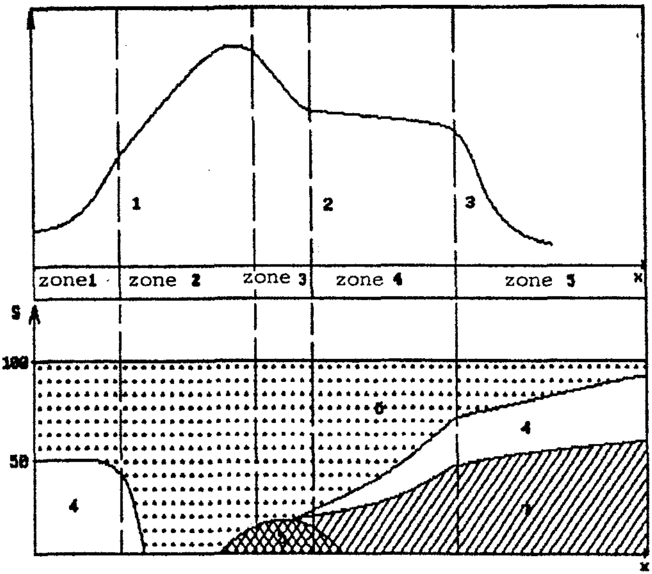

Fig. 2.9. Distribution of temperature zones and oil-saturation at in-situ combustion:

1- steam formation front; 2- combustion front; 3- condensation front; 4- water; 5- coke; 6- gas; 7- oil.

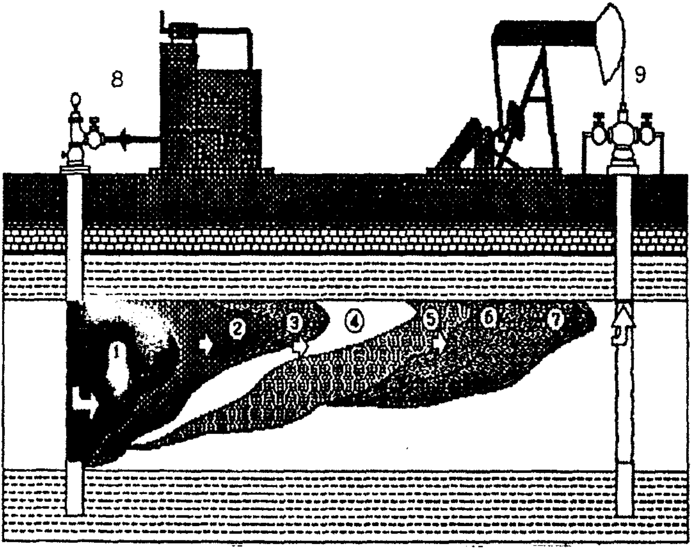

Fig. 2.10. Characteristic zones of oil displacement at in-situ combustion: 1- air and water (burnt out) injection zone; 2- air and water vapor zone; 3- combustion zone and combustion front; 4- steam zone; 5- condensation or hot water zone; 6- oil bank; 7- combustion gases; 8- injection well; 9- production well (oil, water, gases).

formation is burnt which is observed in the interval of the temperatures corresponding to the sulfide oxidation reaction followed by heat release. It explains an increased reactivity of oil saturated KS reservoir rocks (juxtaposition of oil and pyrite).

Thus, under in-situ combustion it's necessary to take into account the possibility of oxidation of the minerals composing the rock and interaction of oil oxidation products and porous medium.

According to Dzhamalov and others [20], Mekhtibeili P.M. [40] and others thermal drive of the producing formation of the Apsheron Peninsula (Balakhansk sand, horizons IV med and KC_1) results in autogenous formations of clay minerals. The content of clay fraction in rocks IV_{cp} and KC_3 before oxidation amounted to 9.23 and 52.63, after oxidation it increased to 16.26 and 64,33 % respectively. Along with the increasing clay mass in rocks after oxidation the content of amorphous mass, which together with clay decreases the rock permeability, increases. Clay content and composition depend on the initial clay material and chemicalization of formation waters. It has been stated that when some ions (Li, NH_4 and others) are present in steam, a negative thermal influence on permeability reduces. With technology of steam-flooding or in-situ combustion the temperature usually doesn't exceed 500-600 °C.

These temperatures are not enough for dissociation of pure carbonate minerals into CaO and CO_2. In the presence of clay minerals and Na salts there is observed some decrease of carbonate rock dissociation temperature. Thus, with content of admixture NaCl to 10 % the dolomite dissociation temperature reduces from 700 to 600 °C, that is, it may occur at the temperatures which reach at in-situ combustion. Dolomite decomposition causes the formation of a considerable amount of CO_2 resulting in an increase of the total pore volume of carbonate rocks.

It should be point out, as the works of Perry and Zhilloti [74], Boon [65], Reed [78] and others show, that most of reactions of mineral transformations depend not only on temperature influence but to a great extend on geochemical medium peculiarities (galinity, pH of the present water, partional CO_2 pressure, as well as duration of thermal influence).

According to works by Park [69, 70] who studied the bituminous dolomite clay shales of Green-River the dolomite decomposition took place at heating to 600 °C in CO_2 atmosphere for 80 hours, and for 40 hours in nitrogen atmosphere. At 760 °C dolomite completely dissociates for 1-2 hours. Periclase is formed at dolomite dissociation. Quartz content in these shales remains constant to 700 °C, but at higher temperatures it gradually reduces forming silicates. Calcite content at 600 °C increases at the expense of dolomite decomposition, but at 760 °C it sharply decreases and disappears in 4-5 hours in CO_2 atmosphere and in 2 hours in nitrogen atmosphere. In this case silicates (akermanite, diopcide and others) are formed.

Strong alkaline steams (pH =11) may cause dissolution of siliceous rocks.

Changes of some minerals composing reservoir rocks under temperature influence at thermal drive may be used as indicators of thermal front travel along the formation. In addition to clay mineral transformations mentioned above, glauconite changes its colour from bright-green to grey-green at 175 °C, and at 200 °C it becomes grey and brown-grey. Changes of rock colour may be indicators of thermal drive temperatures. Thus, according to Petrovskaya et al [44] the oil-saturated rocks possess dark-brown colour which becomes black at 250-300 °C and yellow under 500 °C for 7 hours; after burning at 700 °C it is bright-yellow-reddish because of metal oxides.

The process of dry burning (700°C and higher) is only used in terrigenous reservoirs because carbonates decompose at these temperatures.

2.3. **Physico-chemical oil recovery methods (PCRM)**

Injection of chemical reagents causes a spectrum of physico-chemical mechanisms of oil displacement. Thus, injection of aqueous surfactants, acids, alkalini, polymers results in property changes of formation water and interface between water, oil and rock, in the decrease of relative mobility parameter and improvement of oil-washing properties of water.

The decrease of relative mobility of oil and gas increases formation coverage by stimulation and oil displacement factor, improves rock wettability by water.

2.3.1. **Surfactant water solution injection**

ПАВ

Adding surfactants (or their compositions) to injected water in order to regulate molecular surface properties of rocks and fluids saturating it became known as method of injection of aqueous surfactants.

This method was one of the first EOR methods and was tested since the 50s both in Russia and abroad. However, satisfactory results haven't been achieved because of high absorption and low potential possibilities of low-concentration surfactants. Nowadays, main attention is paid to creating highly effective composition of high-concentration surfactants (5-10 %) and various mixtures of chemical agents with obligatory low interfacial tension of chemical agents and oil.

Basic mechanisms of oil displacement by surfactants

Surfactants are substances with assymetric structures and consisting of hydrocarbon radical and polar groups. Moreover the polar groups are mainly hydrophilic and at the oil-water interface they sink into aqueous phase while radicals are hydrophobic and are oriented to the side of an oil phase which is less polar. Such a structure of the substance is the reason for a surface activity (that is, when the substanes diffund through all the water fringe, they are concentrated at the oil-water interface, thus reducing surface tension between oil and water from 50 to 7 mN/m. In some cases to recover additionally the residual oil it's necessary to use surfactants which reduce interfacial tension to 0.01 mN/m.

When a surfactant enters the pore volume containing oil, emulsion is formed. The type of emulsion can be explained by Bancroft diagram (Fig. 2.11). Oil-water emulsion is formed in case when the surfactant is water solvable, otherwise water-oil emulsion is formed (if the surfactant is oil soluable). When water-oil emulsion moves along the formation, it absorbs oil drops and bound oil layer appears. Bound oil layer appears at a definite threshold temperature value (see Fig. 2.12) which is called temperature phase inversion. At a threshold temperature value the interfacial tension becomes minimum when the surfactants migrate from aqueous phase into oil place thus forming water-oil emulsion. As Fig. 2.11 shows there exist simultaneously 3 phases (oil, water and oil, water and surfactant phase) within the temperature phase inversion. Viscosity of water-oil phase is higher than that of oil-water and clear water phases, that is, this phase possesses the properties characteristic of polymer solution. The temperature of phase inversion increases with the increase of temperature. Ionogenous surfactants have higher temperature of phase inversion as compared with that of non-ionogenous ones due to higher hydrophylic properties. Another mechanism for improvement of oil displacement by aqueous surfactant solution is adsorption of surfactant molecules on the walls of pore channels causing changes of rock wettability character. It happens because of formation of more hydrophobic surface film than the original one, as well as because of

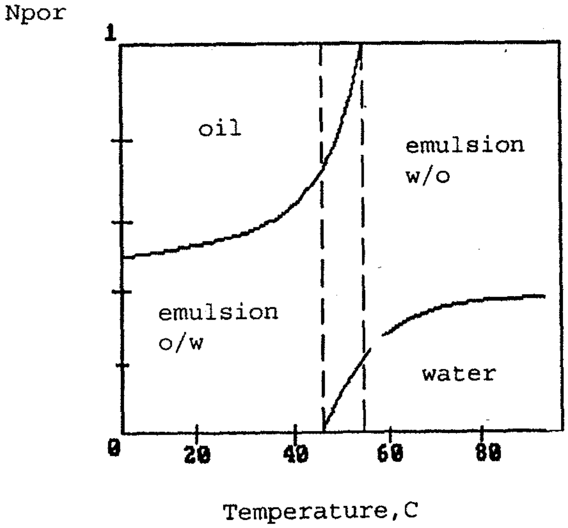

Fig. 2.11 Bancroft diagram to determine the type of surfactant emulsion (separated zone – zone of phase inversion temperatures).

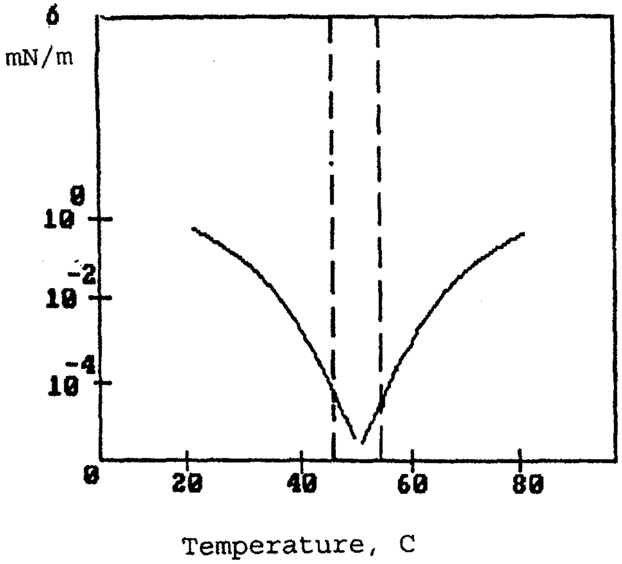

Fig. 2.12. Dependence of interfacial tension on temperature (separated zone – zone of phase inversion temperatures).

dispersion of heterogenous systems and stabilisation of disperse systems. Dispersion of heterogenous systems depends on surface tension decrease. A protective action of surfactant films is characterised by adsorption activity connected with retaining a monolayer on the interface. Stabilisation of disperse systems is determined by maximum amount of stabilised particles. In this case contact angle increases from 18 to 27 °C. All these processes decrease the value of wettability tension 8-10 times. As a result of the above mechanisms, the following processes occur in the formation:

- wettability of pore channel surface by displacing water;
- decreasing of surface tension at oil-water interface;
- oil displacement from the surface of pore channels;
- oil dispersion by water flow, (that is by changing oil bound with rock into free state).

Let's consider adsorption mechanism in details.

Adsorption is a process of increasing molecule concentration on the interface which results in appearing of an adsorption layer.
Desorption is a process of decreasing molecule concentration of the interface.

Sorption rock activity decreases in the row: clay, aleurolites, clay sandstones, polymictic sandstones, dolomites, limestones, anhydrates. A share of film and strongly sorbing oil on the rock surface changes in the similar way.

In case the surfactant solution contacts with the surface of the pore channel, thermodynamic equilibrium breaks and two-dimensional and then three-dimensional associates are formed in the adsorption layer. Single surfactant molecules are concentrated above them and surfactant micellars are located higher (conglomerates of colloid surfactants forming at concentrations higher than critical concentration of micellar formation (CCMF) and possessing characteristic size from several nanometres to a micrometre) (see Fig. 2.13).

Surfactant classification by ion characteristics:

- nonionogenous;
- ionogenous.

When nonionogenous surfactants dissolve in water, they don't dissociate into ions while ionogenous surfactants dissociate into ions when dissolved in water.

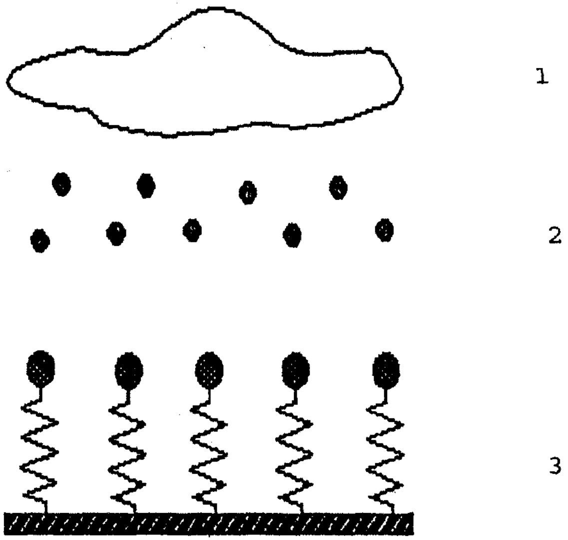

Fig.2.13 Mechanism of surfactant adsorption on the rock surface.

The main technologies of realization of aqueous surfactant injection method.

1. Injection of aqueous nonionogenous surfactants.

Nonionogenous surfactants include the following substances:

- OP-10 (foreign analogs Ethylan KEO, Ethylan 77, Intekon NP-3, Triton A-207, Triton N-101, T-DET-N 6.6 and others);
- OP-7;
- OP-4 (foreign analog Ethylan 44, Triton X-363 and others);
- Prevocel W-ON; W-OF;
- Conox J-109.

Nowadays OP-10 and its analogs containing from 10 to 20 groups of ethylene oxide are most effective for oil field development. Application of these reagents causes minimum surface tension and adsorption on the rock surface. With higher heterogeneity of pore space and hydrophobility of pore reservoirs the efficiency of water solutions of nonionogenous surfactants increases.

2. Injection of water ionogenous surfactants.

The following reagents are used as ionogenons surfactants:

- DC-PAC (foreign analog of Stanyl 40, Alkanol WXIV and others);
- sulfanol NP-1 (foreign analogs of Idepal Na, Tenzopol Seric);
- Sulfanol NP-3.

When deposits with poorly permeable reservoirs are developed, application of low-concentration aqueous ionogenous surfactants may be not efficient enough.

3. Injection of compositions on the base of nonionogenous surfactants.

One of the most efficient technologies is injection of compositions of foaming surfactants, gaseous reagents, special substances for heating the compositions and water. In heating the reaction of the injected composition with formation fluids and rock minerals with releasing of a considerable gas amount is observed. Pore channels of high porosity «are blocked» by gas bubbles causing the fluid to move along less permeable interlayers. Injection of such compositions enables to increase the displacement coefficient by 17-25 % because of additional washing off of residual oil. It's a more prospective technology of surfactant application along with surfactant injection jointly with polymer solutions and as a component in micellar flooding [1, 25, 29, 35, 46].

The main problem encounted in realization of water surfactant injection method is a discrepancy between forecast calculations and field tests. A number of researchers explain it by a negative influence of high surfactant sorbing on the rock skeleton resulting in a sharp decrease of bed stimulation sweep. A negative influence of natural formation microflora on the efficiency of surfactant application has been observed as well. The main direction of research is a creation of high-resistant surfactants with low sorbing which may be used in a wide spectrum of changing geologo-physical factors. The research centres of oil firms carry out research on creating surfactants which could be resistant at temperatures to 120 °C, mineralization up to 200 g/l, rock permeability up to 0.01 mcm^2, formation oil viscosity up to 10 mPa×s and with low adsorption activity.

Lately there has been observed a decrease in the amount of projects with the technologies of using pure surfactants and a sharp pure surfactants and a sharp increase of the projects applying combined methods: (surfactant+polymers, micellar solutions+polymers+surfactants; surfactants + foam, etc.).

Fig. 2.14 shows a scheme of oil displacement by aqueous surfactant plug. In the vicinity of the producing well there is a zone of an initial state followed by the zone of a joint oil and water filtration where a surfactant is not present or its concentration is not sufficient. The next zone is a zone of an oil bank which contains oil additionally displaced from the area occupied by a surfactant plug. The zone of an oil bank is separated from the fringe area by the sorbtion front where condensation of surfactant molecules on the oil-water boundary surface takes place and where the adsorption area begins (i.e., the area where a surfactant adsorbs on the surface of pore channels). The zone of surfactant fringe is followed by the zone of injected water which pushes a high concentration surfactant fringe through the formation. This zone contains only residual oil and water.

The disadvantages of the aqueous surfactant injection method: - surfactant adsorption on the rock which in porous media may achieve a considerable value (up to 15-60 kg/m^3). In this case the following dependence is observed: the higher the oil-saturation, the higher the surfactant adsorption by rock is [30];

- weak biodecomposition of artificial surfactants and higher environmental pollution caused by it,
- high sensibility to water quality (when preparing aqueous solution).

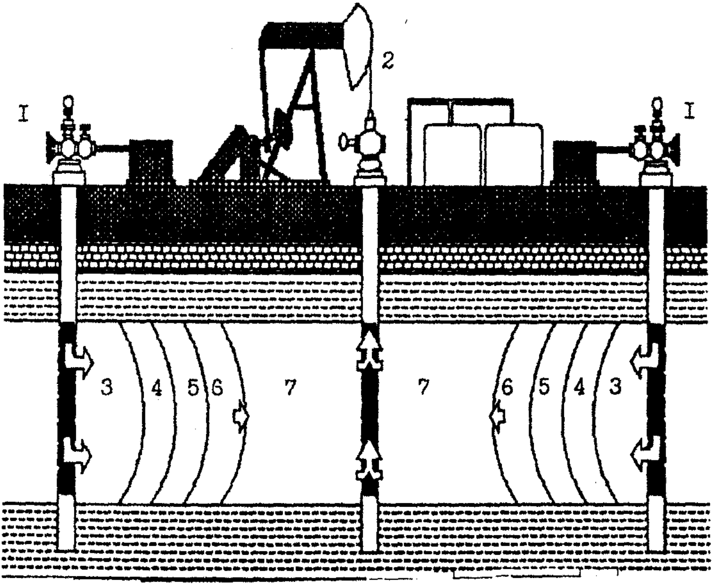

Fig. 2.14 Scheme of oil displacement by aqueous surfactant plug^
1- injection well; 2- producing well; 3- pushing liquid (water); 4- buffer (fresh water); 5- surfactant solution; 6- oil bank; 7- zone of initial formation state.

A great importance for successful surfactant application is its chemical stability, value of residual formation oil-saturation, formation heterogeneity and the degree of surfactant adsorption by the rock skeleton. Surfactant change into oil improves oil mobility, prevents its sticking to a hard rock surface.

An increased content of clay material in the rock, especially if it is presented by swelling components, stipulates its high specific surface on which active surfactant components are adsorbed from the solutions injected into the rock, reduces the efficiency of a displacement process. In the development the extended surface of reservoir pore space adsorbs active oil components forming a film thus resulting in filtration attenuation because of contraction of filtration channels. As a result of adsorption clay sometimes turns into a part of an agrillo-organic complex with the properties opposite to the initial clay-hydrophobic surface, unswelling low-ion exchange property and small specific surface. Reservoir rocks of the Lower Cretaceous of the Middle Priob, especially Nizhnevartovsk roof are characterized by a very extended specific surface of porous space due to a high content of clay minerals. This specific feature of the reservoir causes a greater surfactant sorbtion reducing the process efficiency. The surface of porous space of these reservoirs intensively sorbs active oil components forming a film which contracts an effective diameter of porous space and reduces permeability. The thickness of the sorption film depends on temperature and pressure. A higher temperature weakens the aggregative force of the HC with the surface of pore wells and restores the initial permeability [51].

2.3.2. **Polymer water solution injection**

The method of polymer water solution is an injection of sub-concentration solution of polymer, a high-molecular chemical reagent. Polymers are substances of high-molecular mass of the order 10^4-10^6. They are giants of a chain composition. This substance can considerably increase water viscosity (see Fig. 2.15), thus reducing its mobility resulting in increased bed stimulation sweep (as compared with a conventional waterflooding).

The polymer flooding is used in oil-bearing formations with a considerably high oil viscosity and the mobility ratio of oil and water coefficients, as well as a moderate heterogeneity. The method of polymer flooding is not used for development of oil deposits with gas caps, fractured reservoirs, high permeability and active bottom-water drive. An

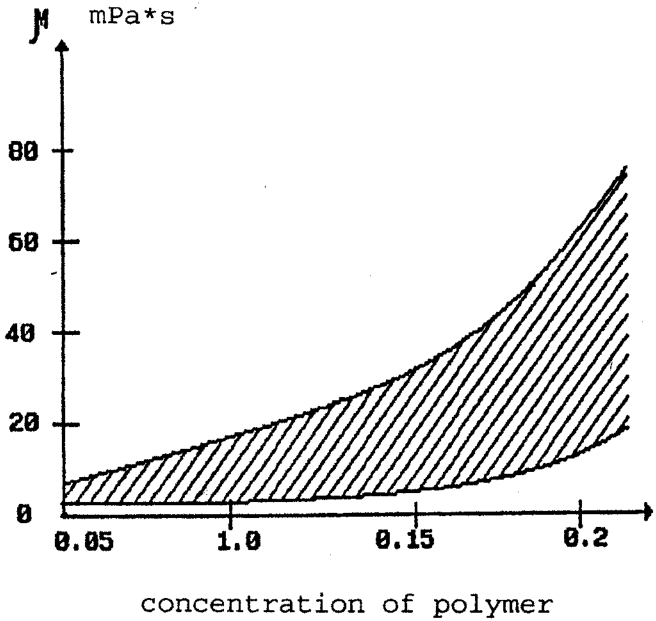

Fig. 2.15. Viscosity of thickened water depending on polymer concentration (for various types).

oil recovery increase averages 3-10 %. The sizes of polymer fringe vary from 0.1 to 0.4 pores (of pore volume). When polymer is applied, the mobility ratio decreases and, respectively, the lateral and horizontal bed stimulation sweep factor increases. The mobility ratio of water and oil coefficients is presented as:

$M=\lambda_w/\lambda_o$,
where $\lambda_i=K_i/\mu_i$, $i=w, o$ - mobility coefficients of water and oil respectively, K_i, i - phase permeability of water and oil, respectively;
μ_i, $i=w, o$ - viscosity of water and oil, respectively.

The dependence of bed stimulation sweep factor for a five-spot well system (WS) on the cumulative volume of pumped thickened water is shown in Fig. 2.16. Oil viscosity was regulated by adding polymers thus increasing viscosity of injected water and decreasing ratio of water and oil mobilities
$\lim m \to 1$
$\mu_w \to \mu_{w\ max}$
and increasing sweep efficiency coefficient (K_{sweep}).

The method of polymer water solution injection was tested since late of the 50s. This method is one of the most efficient recovery methods. The main mechanisms of enhanced oil recovery in polymer water solution injection are:

- water thickening resulting in lower ratio of oil and water mobilities and decreased ability of water breakthrough into the producing wells;
- clogging of high-permeable channel because of polymer adsorption on the rock surface. Sweep efficiency of low-permeable reservoirs increases in this case.

It should be noted that the apparent viscosity of polymer water solutions μ^* increases with greater filtration rate and smaller sizes of pore channels. The apparent viscosity may be 10-20 times higher than that of the measured one. The apparent viscosity of the polymer solution is determined as: $\mu^*=\tau/\gamma$, where τ - tangential shear stress, γ - shear rate (gradient). Usually the dependence of the apparent viscosity of the polymer solution on shear rate is represented in Fig. 2.17. Constant viscosity value μ, i.e., Newton behaviour, may be observed both at low and at high shear rates. The maximum viscosity rates μ_{∞}, μ_0 are called lower and upper maximum viscosity. Fig. 2.17 shows that the Newton rheologic equation may be used to describe the behaviour of polymer

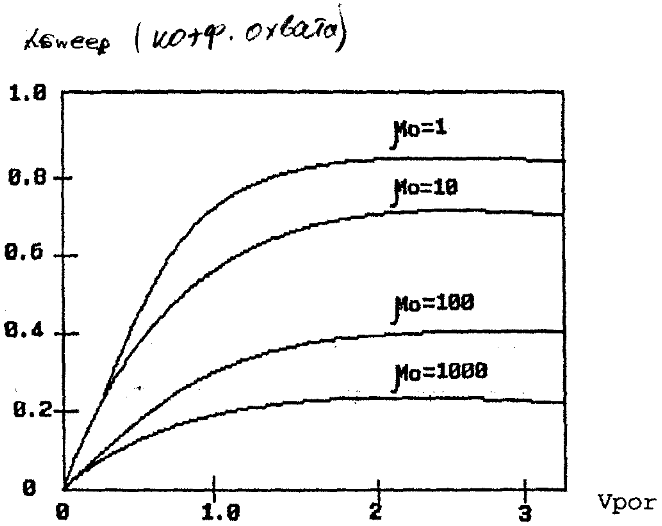

Fig. 2.16. Dependence of bed stimulation sweep for a five-spot well system on the cumulative volume of the pumped thickened water for various ratios of oil and water viscosity μ_o.

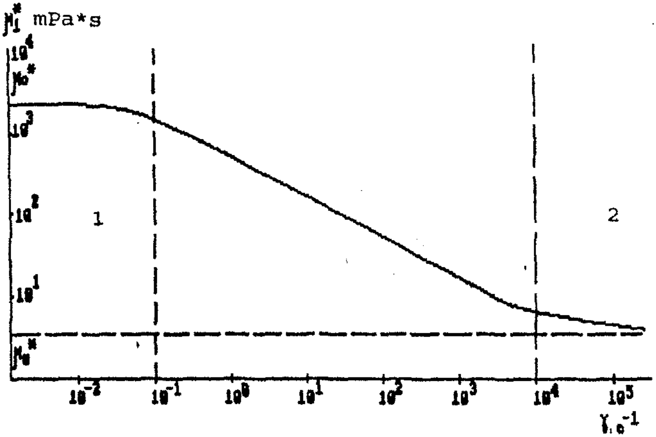

Fig. 2.17. Dependence of apparent viscosity of polymer solution on the shear rate.

solutions in porous medium at shear rates up to $\gamma < 10^{-1}$ s^{-1}. At shear rate (gradient) from 10^{-1} to $< 10^{-1}$ s^{-1} characteristic of polymer flooding the polymer solutions with high initial viscosity exhibit structural viscosity. At the same time when polymer is injected and passes through perforation holes the shear rates (gradients) may be of order $10^{3} + 10^{4}$ s^{-1}. Moreover, shear rate increases in the bottom-hole formation zone (BHFZ) and then sharply decreases up to $0.1 + < 10^{-1}$ s^{-1} .

At high shear rates a mechanical destruction of polymer chains takes place. It results in reduced viscosity and FP. Moreover, FP reduced faster than polymer viscosity. At constant stress the temperature increases.

Polymer adsorption by the porous medium surface increases, if formation water salinity increases and formation permeability reduces and may amount from 0.007 to 0.75 Kg/m^3.

The quantity of the adsorbed polymer depends on the porous medium structure, its material and component composition, properties of fluids, like polymer, which saturate the porous medium, its concentration, molecular weight, filtration rate in porous medium, temperature and ph value. Adsorption on the rock surface depends on the type of the polymer. Thus cationactive polymers are not used at OFD because of the fact that they are adsorbed in considerable amounts on the rock skeleton. In OFD the anionactive polymers (polyacrylamides - PAA) are mainly used. PAA adsorption increases with the growth in their molecular weight. In this case part of PAA is adsorbed on the rock wells unreversably and it is proved by the desorption tests. When the volumetric flow rate of polymer water solution increases, the adsorption on the rock surface increases and polymer influence on the low-permeability and porous zones becomes greater. As a rule at volumetric flow rates characteristic of OFD, about 30 % of V_{pore} happens to be inaccessible for polymer solution. Figs 2.15, 2.16 don't take into account the change of absolute rock permeability because of adsorption of polymer molecules on the rock skeleton.

To consider this phenomenon it's preferable to use «resistance factor» (RF) which reflects the ratio of water and polymer solution mobilities as $RF = \lambda_w / \lambda_p$, where λ_i, $i = w,p$ - water and polymer mobility respectively.

RF in common case is more than a unit or is equal to it. Phase water permeability reduced as well because of joining water molecules to polymer molecules. RF is greatly influenced by a mechanical destruction of polymer chains in addition to thickened water viscosity. For the mechanism of oil displacement by polymer solution it's very important to

determine the residual resistance factor (RRF). It is determined as the ratio of injected water mobility before and after polymers are added:
$RRF=\lambda_{w\ init}/\lambda_{w\ fin}$; RRF reflects a decrease in phase rock permeability for water due to using polymer as usual, $RRF \leq 10$.

To displace oils the following agents are used as polymers:

- polyacrylamides:
  - nonionogenous,
  - partially saponificated anion-active;
- cellulose-base polymers:
  - oxyethylcellulose;
  - polysaharides;
  - polyethylenoxides.

Completeness and rate of polymer dissolution in water determine the efficiency of polymer flooding. The dissolvents may be both fresh and mineralized water with different pH values and general mineralization. However, salts of chlorine ion, calcium chlorine and natrium chlorine considerably reduce the viscosity of thickened water. The solution viscosity is also observed to reduce if the total formation water mineralization increases. Polymer destruction has a negative effect on efficient oil displacement. The destruction may be chemical, thermal, mechanical and microbiological.

The rate of polymer water solution injection depends on various factor:

- rheology of polymer solution (viscosity, elongation and viscoelasticity, pseudoplasticity),
- increased amount of seamed gel particles.

The amount of seamed gel particles is growing due to the seaming action of calcium, manganese and iron cations in formation water, as well as due to insufficiently fast dissolution of polymer. The higher the rate of injection, the lower the polymer viscosity (pseudoplasticity) is, and the lower is RF. At the same time we can observe the properties of prolongation and viscoelasticity of polymer solutions. At low injection rates the relaxation period (l/e) is much less than the characteristic deformation period. In this case there is observed viscous fluid flow (behaviour) at which there is enough time for the polymer solution to pass through a complicated pore system. At high injection rates of polymer water solution, a characteristic relaxation period corresponds to a characteristic deformation period and an elastic fluid flow (behaviour) is observed. An elastic flow of polymer water solution results in a considerable inhibition when the solution passes through the pore tortuosity. The bottom-hole formation zone (BHFZ) is characteristic of high volume flow velocity of polymer solution. In this zone we observe both an effect of viscoelastic behaviour of polymer solutions and an effect of mechanical destruction of polymer chains. These two effects considerably influence a successful realization of polymer flooding. It should be pointed out here, that the viscoelastic phenomenon is observed and the mechanical destruction takes place mainly at the distance of 1/r - (where r- radius of an injection well). At this distance the volume flow velocity reduces 4 times. At larger distance from the bottom of the injection well the RF (-RF_0) becomes independent on the volume velocity of polymer water solution.

Polymer chemical destruction depends on such factors as: availability of calcium and magnesium cations; presence of radicals (oxygen and others). PAA, as a rule, possesses heat endurance only because the system of polymer groups is free of the substances acting as radicals.

The concentration of polymers in the solution injected into the formations ranges within 0.02-0.05 %. Polymers on cellulose base (carboxymethyl cellulose, oxyethyl cellulose) have found such a wide application neither in OFD nor in PAA. There are only some pilot tests with oxyethyl cellulose. The latter consumption happened to be high due to low molecular weight. At high volume filtration velocities (hence, at high shear rate) the oxyethyl cellulose is characterized by a high viscosity, low elasticity and poor injection. At hydrogen medium factor pH≤6 the oxyehyl cellulose viscosity reduces and it is quickly hydrolyzed. The oxyelhyl cellulose is comparatively stable at pH>6 and has a low sensitivity to shear rate.

One of the ways of combating this phenomenon is to minimize the seamed gel particles. In the case the extent to which polymer groups twist reduces and the polymer extension factor increases. One of the factors regulating the efficiency of polymer flooding is the ratio of molecular diameter and pore diameter $Kd_p/d_{pore}=d_p/d_{pore}$. Characteristic molecular diameter of polymers are: 200÷5000 λ° and of pores: 10.000 λ°, thus, characteristic values Kd_p/d_{pore}: $Kd_p/d_{pore} = 0.02 \div 0.5$. Gel formation results in a sharp reduction of formation permeability. Calcium, magnesium and iron salts, especially the latter ones, cause the growth of gel particles. In their presence polymers become seamed and thus the formation of geleous particles takes place. The more the polymer molecular weigh to 3×10^6 is, the higher the polymer adsorption is, because long chains of polymers are easily gripped in a complicated molecular structure of pore space.

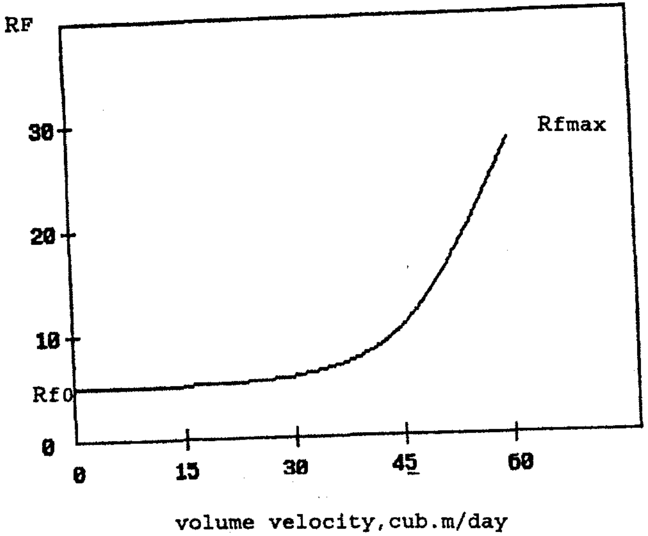

Fig. 2.18. Dependence of resistance factor (RF) on the volume flow velocity of the polymer water solution.

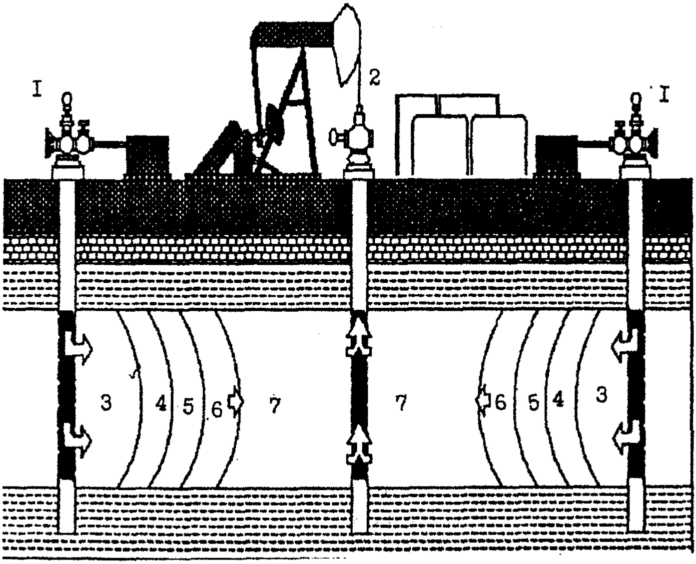

Fig. 2.19. Scheme of oil displacement by the polymer water solution bank.

Fig. 2.19 presents a scheme of oil displacement by the polymer water solution bank.

To prevent polymer contact with highly mineralized formation water, in some cases fresh water of V_{pore} volume (0.05-0.1) is injected into the formation before polymer bank.

2.3.3. Alkali water solution injection

The method of alkali water solution injection is the injection into bed of water reagents which cause an alkali reaction. The studies and tests of this method are related to the 20s. However, its wide pilot introduction started in the 70s. The main displacing mechanisms are the following:

- reduction of inter facial tension;
- oil emulsification (fine-dispersion formation);
- change of rock wettability.

These mechanisms are based on neutralization reaction of oil acid components resulting in alkali soap formation which migrate through the interface because of the tendency of the system to thermodynamic equilibrium. Alkali soaps are formed directly in place of oil and alkali contact. The minimum of interfacial tension (v) is observed in the range of mass alkali concentrations from 0.005 to 0.5 %. It should be noted that an intensive transfer through the interfaces is not very long, somewhat of 20÷40 min. It takes place when interfacial tension (v) reduces lower than 0.001 mN/m. The application of alkali water solutions reduces the contact angle (θ) of rock wettability by water to 10-20 °.

Oil polar components adsorb on the rock surface and hydrophobe it. Alkali solutions are able to return the surface its original properties, that is to hydrophobe it. In this case the wettability (contact) angle drops and in some cases it decreases to zero. Within this range of concentrations the phase dispersion takes place resulting in formation of the emulsions like «oil in water» (or «water in oil»). The emulsion formed in bed reduces the mobility of water phase (or oil phase). Thus oil is extracted from the porous medium due to oil emulsification and its reverse capillar replacement for the alkali solution. The following components are mainly used as alkali reagents:

- sodium hydroxide - $NaOH$ (caustic soda);
- siliceous sodium - Na_2SiO_3 (sodium silicon);
- ammonium hydroxide - NH_4COH (ammonia solution);
- phosphorous sodium - Na_3PO_4 (trinatrium phosphate solution)

The most spread alkali reagents are caustic soda and sodium silicate (especially in combination with surfactants at carbonate reservoir development). Usually the concentration of alkali reagents in water solution changes from 0.05 to 0.5 % but in some cases it may reach 25-30 %.

Figure 2.20 shows the scheme of oil displacement by alkali water solution plug.

Oil, water and low-concentration alkali filter in the zone of mixing. A characteristic feature of this zone is that alkali concentration in it is lower than the value at which emulsion is formed. At the same time the alkali available reacts with the sour oil components resulting in the surfactant formation. These surfactants improve washing out oil in this zone. The activity of interaction of oils with alkali solution has a considerable influence on displacement mechanism. Thus oils are classified by their activity (see Table 2.1)

Table 2.1. Classification of oils by the activity of interaction with caustic soda

Type of oil	Interfacial tension mN/m	Content of organic acids in oil (acid number), mg OAO/g
non-active	>1	0.01 - 0.06
low-active	1 - 0.05	0.1 - 0.25
active	0.05 - 0.01	0.25 - 1
high-active	<0.01	>1

At present the following variants of injection technologies of alkali solutions have been known [18]:

- caustic soda solution (is used in development of high-active oils. Reagent concentration is 0.05-2 %. Fringe size is 10-25 % of pore volume);
- solution of caustic soda and sodium silicate (is used in development of low-active oils. Reagent concentration is 0.1-2.5 %. Fringe size is 10-25 % of pore volume). This technology is characterized by a low oil recovery coefficient;
- alkali solution and water-soluable polymers (are used in development of heterogeneous low-permeable formation and to restrict water influx), polymer adsorption decreasing, formation water mobility

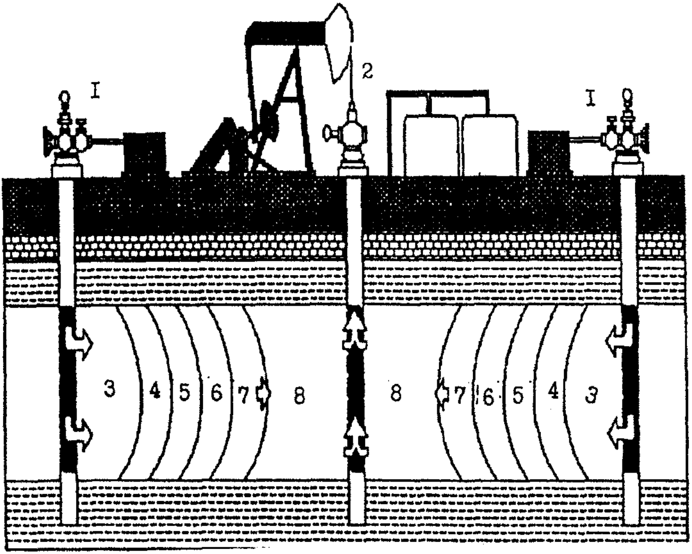

Fig. 2.20 Scheme of oil displacement by alkali plug:
1- injection well; 2- producing well; 3- pushing liquid (water); 5- polymer solution; 6- alkali solution; 7- oil bank; 8- zone of initial formation condition.

sharply reducing, displacement coefficient increasing by 10-20 %. The optimum reagent concentration in this technology is 0.1-0.5 %.

Fresh water is preferable in pushing polymer and alkali solution fringe;

- alkali and surfactant solution (is used in development of low-active oil fields resulting in oil viscosity decrease by 15-20 %, while the oil displacement coefficient increases by 6 %;
- trinatrium phosphate solution (is used even with low-active oils).

This technology results in improved rock wettability, sharp interfacial tension decrease to 3-5 mN/m, increase of displacement coefficient by 3-12%. Interaction of trinatrium phosphate solution with formation water causes precipitation of salts which plug high-permeable layers washed during flooding. This improve filtration characteristics of the formation [30];

- alkali solution together with natural gases (is used to eliminate the effect of high-viscous gas instability due to formation of emulsions and foam in the stratum);
- alkali-silicate flooding (is used to plug pores and to increase sweep-efficiency factor);
- thermal alkali flooding (is used to develop high-viscous and high-active oil fields. Eliminates the effect of high-viscous steam instability and improves oil washing off properties. Oil displacement coefficient increases by 15-25 %). This is one of the most promising technologies.

However, along with positive influence of alkali on filtration characteristics of oil-saturated formation there are observed some factors which reduce their efficiency due to formation of low-soluble sediments (calcium and magnesium salts) resulting in decreased permeability of porous medium, as well as due to intensive alkali absorption by swelling clay minerals composing the cement of reservoir rock (mixed layered minerals montmorillonite). The injected alkali may react with some silicates and dissolve them. The results of this process, though being slow, are very difficult to predict. Alkali solution easily reacts with clay flakes and silicon formations having high-developed surface. An increase of water-soluable silicate concentrations increases the displacing ability of the solution and thus increases oil recovery. When alkali solutions (NaOH, $NaCO_3$) are injected into the producing formation, they are mixed with hard formation water and precipitate as $Ca(OH)_2$, $Mg(OH)_2$, $CaCO_2$, $MgCO_3$. Salt precipitation may be forecast by chemical composition of produced waters systematically withdrawn from all the flooded well stock at any stage of development. These data are used applying statistical dependences of ion concentration on mineralization with computer calculations by existing programs. It should be noted, that in a number of cases the damage of filtration ability of reservoir rocks at alkali flooding is taken into account to increase the sweep efficiency. Thus, an increased content of factor swelling clay minerals in porous medium increases the efficiency of oil displacement by alkali solution as compared with fresh water as a displacing agent. This accounts for smaller pore sizes in washed out zone due to clay swelling and increased the sweep efficiency factor. The sweep efficiency factor increases (according to a technology of alkali flooding developed by collaborators of the UkrGiproNIIneft) [41]. The water solution of caustic soda and formation water which are separated by fresh water buffer is injected into the injection well in turn. The change of sweep efficiency of terrigenous reservoirs of the Yasnopolyansk horizon of the Shigiritsko-Gozhansk field in Perm region is proved by comparison of injectivity profile I of the area before and after injection of fresh water and after alkali flooding. In the first case the sweep efficiency is 0.36 at P injection of 13 MPa, in other cases the sweep efficiency was respectively 0.73; 0.91; 0.63; 0.63 at injection pressure of 16; 8.5; 13 and 19.5 MPa. In conclusion it should be noted that according to B.I. Tulpovich the alkali solutions hydrolyse sandstones, though limestones do not change the character of surface porous space. Precipitation of carbonates, hydroxides and silicates accompany the alkali flooding, the determining value being pH changing from 13.5 to 7.0 in various point of the formation. Then we should point out the paper of Heinemann Z et al «Changes of pore space structure by nonorganic gels to increase oil displacement efficiency» (1982). One of the characteristics of displacement process of nonmiscible phases in porous medium is a capillar number - dimensionless parameter $N_1=U\mu/\sigma_{ow} \cdot \cos\theta$, where U- displacement rate, m/s; μ- viscosity, mPa×s; θ - angle contact and σ_{ow} - oil-water interfacial stress (N/m). For a conventional water drive this value amounts to $N_1\times10^{-7}$. A considerable decrease of residual oil (RO) may be observed only when N_1 increases from 10^{-1} to 10^{-3}. However, an increased viscosity of displacing phase decreases displacement rate and product Uμ increases not greatly. To increase the displacement rate, it's necessary to reduce surface tension by 3-4 orders which is practically impossible on an industrial scale (to maintain this state for a long time). Nevertheless, surface tension decrease by 1-2 orders will increase the efficiency of the whole process. Even a slight reduction of surface tension may happen to be effective if pore channels, which are already filled by displacing phase, are closed and the displacing fluid containing additives of chemical reagents will be injected through other channels. That is, if the structure of pore space changes at the proper time and in the proper place. This is realised «at» controlled alkaline flooding proposed by A.M. Sarem [80]. When 1 % sodium silicate solution with high pH reacts with oil components, it forms surfactants, reduces surface tension and increases oil mobility. Sodium metasilicate solution reduces surface tension between water and oil, changes rock wettability in favour of water. Concentrated sodium metasilicate solution improves viscous ratio and displaces part of residual oil which may be displaced in accordance with the increased capillar number. 11 % portion of dissolved calcium chloride solution following silicate injection forms polyvalent cations for the reaction with ortosilicate resulting in rather a stable fine-granular precipitate in high-permeable channels, curing them and lowering permeability. The portion of sodium metasilicate followed by the portion of calcium chloride solution disperse and form large - volume jelly-like precipitate, partially blocking pore channels. Pressure gradient locally increases and calcium chloride solution removes oil disseminations which used to be immobile. Metasilicate solution moves in front of this oil dissemination followed by calcium chloride solution lowering the surface tension between oil and water.

If oil disseminations stop for some reason, both solutions (sodium metasilicate and calcium chloride) come into contact, pressure gradient increases and oil dissemination go on moving. In the author's opinion this displacement mechanism doesn't displace dispersed oil as drops in pore space because the blocking of surrounding water-bearing channels only results in additional obstacles on the way of these drops. In this process oil disseminations the sizes of which cover the area of rock of several pores are displaced. The size should be defined. The channels already washed remain between the disseminations making the displacing phase with additives remove the disseminations along other channels because of the change of pore space structure in the proper place and at the proper time.

At temperature over 75 °C NaOH solution actively interacts with rock forming sandstone minerals making up aluminum-silicate compounds. This changes reservoir porosity and permeability depending on its mineralogical composition. Both formation improvement and damage may be observed as well. The reaction velocity of reservoir interaction and the quality of products of this reaction depend on mineralogical rock composition and process temperature.

2.3.4. Acid water solution injection (H_2SO_4, NCL)

The main idea of acid water solution injection method is to create in the formation the fringe of concentrated sulphuric acid pushed by water. The method was developed in the 70s and was mainly used in the Tataria fields (the method was developed in the TatNIPIneft).

The basic oil displacement mechanisms are:
- decrease of interfacial tension;
- adsorption of anionactive surfactants which are formed as a result of interaction of sulphuric acid and oil;
- clogging of high-permeable channels washed by water (due to formation of low-soluable salt crystals: sulphate and calcium sulfonate) and calcium sulfonate);
- decrease of oil viscosity (due to heat release when acid reacts with formation water. The formation temperature may increase to 100 °C);
- dissolution of carbonate components by sulfuric acid results in formation of carbon dioxide: 1 t of H_2SO_4 forms up to 0.4 t of CO_2 thus promoting oil displacement mechanism by carbon dioxide and increasing pore channel permeability.

The basic technologies of sulfuric acid water solution injection:
- injection of technical sulfuric acid (93 % concentration);
- injection of alkaline sulfuric acid (wastes of chemical production).

When sulfuric acid water solution is injected, the oil recovery factor increases to 11.2 %. A considerable disadvantage of this method is gypsum formation causing gypsym precipitation in the wells, equipment corrosion and cement breaking in the formation [29].

Sulfuric acid actively reacts both with hydrocarbons of aromatic family and the paraffin hydrocarbons. The products of these reactions are mainly in acid tar, and the surfactants obtained facilitate an increase of phase permeability for water pushed after fringe.

The success of this method is greatly influenced by rock carbonate content. The carbonates contained in the formation allow to neutralize H_2SO_4 when it approaches the producing wells. The latter is very important from the point of preventing the corrosion of producing wells. Thus, carbonate content finally determines the concentration of acid fringe injected into the formation. When this method is used, the amount of realised projects doesn't exceed 20.

The hydrochlorid acid treatment of formation results in irreversible changes of pore space structure and an increase of filtration rock properties. The intensity of these transformations depends of the lithological rock features, quality, type and content of cement and component carbonate content. After hydrochlorid acid treatment the permeability of fine-medium-granular sandstones with gel-cement, carbonate cement of pore and porebasel type increased 3.5 times, the porosity increasing 1.6 times.

The concentration of hydrochloric acid doesn't influence the efficiency of treatment (V.M. Bortnitzkaya and E.O. Aljeshkina) [7]. In hydrochlorid acid treatment not only carbonate but as well chlorite cement is dissolved as it was observed in the rocks of БВ8 Samatlor field formation and БС6 Pravdinsk field formation of the Middle Priob. As a result of partial dissolution of film chlorite cement the structure of porous space improves and the well production rate increases.

According to studies of G.B. Vizhigyn [12] (at 40 fields of the Kujbishev region) hydrochlorid acid treatments of productive formation under pressure negatively influence a complete oil recovery because of solution channels of drainage system between the wells formed in the formations thus resulting in a sharp water encroachment of their production. The more the volume of injection acid is, the higher rock permeability in one direction, to the side of higher pressure gradients is. As a rule, these channels are directed along the bedding plane and represent a sinuous character. G.B. Vizhigyn showed that the completeness and the rate of oil recovery from carbonate deposits of the Kujbyshev Povolzhye considerably reduced (by 22-74 %) depending on the reservoir permeability after hydrochlorid acid treatment under pressure due to «acquired heterogeneity». As a result sweep efficiency under flooding and water drive reduces.

To prevent the formation of solution channels in carbonate deposits G.B. Vizhigyn recommends to replace hydrochlorid acid treatment under pressure by a hydrochlorid acid bath, and in places where the channels are already formed it's desirable to carry out development without waterflooding. The expediency of this fact has been proved by the experience of development of a number of fields confined to carbonate reservoirs of the Kujbyshev Povolzhje. The Kalimovsk and Yablonevsk fields show an increase of the borehole diameter from 15 to 20-30 cm after 10-15 years of exploitation and repeated HATS. All the surface of the open borehole is corroded by caverns of 2-3 mm diameter.

2.3.5. Alcohol water solution injection

This method was developed in TatNIPIneft. The main mechanisms of oil displacement by alcohol water solution (acetone) are the following:

- bound water absorption by alcohol (acetone);
- absorption of water found in the interlayer space of crystal lattice of montmorillonite clays;
- water absorption and withdrawal resulting in the compression effect of swelling clays.

The above mechanisms contribute to an increase of relative permeability to oil.

Disadvantages: the compression effect of montmorillonite clays is reversible.

After passing through alcohol fringe, in case it is advanced along the formation by water, the permeability is expected to reduce. So it's recommended to add clay stabilizers to the injected water following the fringe.

2.3.6. Micellar polymer flooding injection

Micellar-polymer flooding injection is the method of oil displacement based on a successive injection of micellar solution or microemulsion fringe (with very low interfacial tension) or polymer water solution fringe. The polymer fringe is used as a mobility buffer to prevent the intrusion of unthickened water through high-viscous micellar fringe, fingering and micellar fringe spreading. The method was developed and tested in the USA. Since 1962 this method has been under pilot operation. After flooding about 30 % of all terrigenous (clastic) deposits may be applicable for this method. The basic obstacles preventing the application of this method are the following:

- strict sequence of carrying-out complex technological operations.
- high sensitivity to geological-physical parameters: mineralization, salinity, formation temperature;

- high requirements to the quality of water used to prepare the reagent;
- high cost of main components of miccelar solutions - oil sulphanates and alcohol stabilisers.

In micellar - polymer flooding the main mechanism of oil displacement is that a high-viscous micellar solution greatly decreases interfacial tension to superlow values (up to 0.001 mN/m).

This results in elimination of the action of capillar forces and the micellar solution seems to absorb water and oil. The increased viscosity of miccelar solutions (which changes from 10 to 2000 mPa× c) improves the mobility ratio of oil and displacing fluid and increases the sweep efficiency factor. The efficiency of the above mechanisms of oil displacement sharply reduces in the presence of high concentrations of calcium salt and magnesium in formation water, as well as in case of heterogeneous oil reservoir structures [29].

The main mechanisms of micellar - polymer flooding. Surfactants may form miccelars which make mixing oil and water easier.

This process is named **Solubilization** - the process of matter solubility (including water - unsoluble matter) in the surfactant solutions because of miccelar intrusion. Solubilization is characterised by ability of spontaneous dissolution of matters under common conditions in the solvent of unsoluble ones. Hydrocarbon solubilization increases at higher surfactant concentration. Keep in mind that miccelars are conglometates of colloid surfactants in a solvent. The solubilization parameter in miccelar solution is the ratio of oil volume to the surfactant volume. On one hand, the mixture containing micellars may be determined as microemulsion, that is, it contains dispersed particles of a submicroscopic size. On the other hand, the mixture possesses the properties of the solution, namely, precipitation stability and optic permeability. There are distinguished shed oil-base micellars on which surface there are water molecules and water-base micellars on which surface there are oil molecules. It is explained by the fact that when micellar is formed, the thermodynamically stable (lyophilic) groups are turned to the solvent, while the thermodynamically unstable (lyophobic) ones form the micellar nucleus. Such an organisation provides a minimum interfacial tension on the border of miccelar-medium. The most spread solvent is water, so we can very often meet the micellars of «oil in water» type.

In addition to surfactants, water and hydrocarbon fluids (gas, water, kerosene) are:

- sodgergent - alcohol which serves for solution stabilisation, viscosity regulation and improvement of water or oil solubilization processes;
- elecrolite - sodium chloride or ammonium sulphonate to regulate solution viscosity.

Nowadays two technologies are basically used:

- injection of highly concentrated micellar solutions which contain 8-10 % of sulphonate, 2-3 % of stabilisers and up to 50-70 % of hydrocarbons. The size of a fringe is 5-10 % of pore volume;
- injection of low concentrated micellar water solutions which contain 2 % of sulphonate, 3 % of hydrocarbons and 0.1 % of stabilisers. These solutions do not mix with oil, though they provide a superlow interfacial tension . The size of a fringe is 20-50 % of pore volume.

The expected oil recovery due to application of micellar - polymer flooding abroad is 300 m^3/daily in 1993 [29].

Figure 2.21 presents the scheme of oil displacement from hydrophilic porous medium. In this case the dispersed residual oil left after flooding forms the zone of oil bank before the miccelar fringe (separate oil drops merge into continuous medium). Water accumulates behind the oil bank and water bank is formed. This fringe is displaced by spacer fluid - polymer fringe. Oil saturation behind the micellar and polymer fringe is very small. On the border of the fringe the micellar solution comes into contact with a small amount of water and oil. A considerable part of oil doesn't even contact with micellar solution. The spacer fluid is injected to increase a regular sweep by flooding. The spacer fluid is followed by injection of ordinary water till the end of the development (mainly 10-15 years).

In the hydrophobic porous medium the water and oil bank can be replaced. In the presence of highly mineralized formation the micellar solution fringe may be followed by injection of the fringe of fresh or poorly mineralized water with sodium chloride.

At present two basic technologies are used:

- injection of highly concentrated micellar solution with the fringe of 5 - 15 % of pore volume and 30 - 60 % of spacer volume,
- injection of low -concentrated water micellar solutions with the fringe of 20 - 50 % of pore volume.

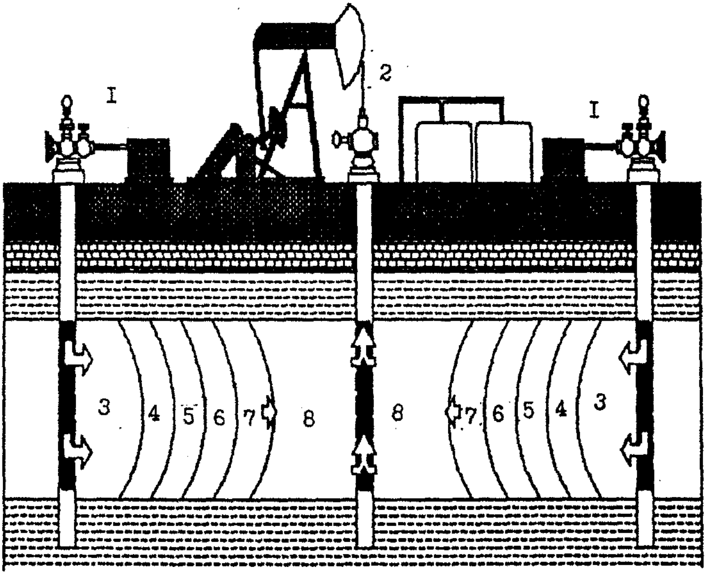

Fig. 2.21. Scheme of oil displacement at micellar-polymer flooding:
1- injection well; 2- producing well; 3- displacing fluid (water); 4- buffer (fresh water); 5- polymer solution; 6- micellar solution; 7- oil bank; 8- zone of initial formation zone.

2.4. Gas injection methods

A successful application of gas methods is mainly influenced by the occurrence depth (condition of miscibility of gas agents with formation oil), formation thickness and lithology. The formation must be characterized by high bed intake at considerable pressure. Additional oil recovery due to application of gas methods amounted to 19.355 mln. ton in 1989.

2.4.1. Carbon dioxide injection

The method of CO_2 injection is based on the ability of carbon dioxides to dissolve both in water and in oil. Carbon dioxide began to be used for oil extraction since late of the 40S and now it is one of the RMS which is used in commercial oil field development.

The factors influencing CO_2 application are:

- precipitation in the formation;
- corrosion of oil - field equipment;
- difficulties of transportation and storage of large volumes of CO_2;
- CO_2 absorption in the formation (to 70 % of the injected volume);
- lack of CO_2 resources in the regions of oil field location.

Oil displacement in carbon dioxide injection occurs because of the action of the following mechanisms:

- oil and water viscosity change. Oil viscosity greatly decreases while water viscosity slightly increases (by $1.2 \div 1.3$). This results in a considerable improvement of oil and water mobility ratio and an increase of formation sweep by 8 - 20 %;
- an increase of oil volume by 1.5 - 1.7 times (because of carbon dioxide enrichment). It provides an effective oil displacement and additional washing out of residual oil. A very great increase of oil volume is observed in the development of light oil fields;
- a slight increase of oil density;
- miscibility of CO_2 and oil which is characterised by the process of evaporation of hydrocarbons from oil and CO_2. Miscibility means an ability of CO_2 and oil to mix in unlimited portions and to form a single phase without an interface between them. Hydrocarbons from C_6 to C_{30} may dissolve in carbon dioxide and it's very important for development of high-viscosity heavy oils;
- reduction of interfacial tension on oil-water contact thus improving the rock wettability and washing out the oil films;

- formation of carbonic acid (H_2CO_3) when CO_2 dissolves in water which is able to dissolve some types of cement and carbonate rocks.

In this case rock permeability increases: sandstone permeability increases by 5 - 15 % and carbonates by 6 - 75 %. The most sufficient factor influencing a successful application of CO_2 method is viscosity of formation fluids, small oil saturation and formation heterogeneity [74, 79].

If CO_2 is in gas phase, it dissolves in water and oil and vice versa; if CO_2 is in liquid phase, water dissolves in carbon dioxide and light components of oil transfer into gas phase.

The factors influencing CO_2 application are:
- lower formation sweep (as compared with a conventional flooding);
- incomplete mixability with oil and in this case light hydrocarbons (heavy oil fractions remain in the formation) dissolve in CO_2;
- well corrosion;
- CO_2 utilisation.

The mechanism of oil displacement by CO_2 has its peculiarities depending on the fact whether the displacement process is miscible on nonmiscible. The scheme of oil displacement by carbon dioxide is presented in Fig. 2.22. In case of nonmiscible displacement the oil displacement factor is lower than in miscible displacement. As a result, in the formation there occurs a three - phase filtration which is characterised by increased filtration resistance and the sweep efficiency factor is higher in a complete mixing. The reason for using non-miscible oil displacement by CO_2 is a lower cost of the process and the required injection pressure In the process of miscible oil displacement by carbon dioxide, CO_2 dissolves in oil and in water. In the former case oil is swelling, its viscosity reduces and mobility and capillary water penetration by porous medium improve.

In the latter case oil viscosity increases and its mobility decreases, the surface tension on the oil-water interface reduces.

Natural gas and nitrogen injected with CO_2 deteriorate the conditions of miscibility. The method of CO_2 is effectively realised in the USA fields and nowadays it takes the third place after steam injection by the level of oil recovery. Moreover, 98 % of oil recovery by this method fall by miscible oil displacement by CO_2 and only 2 % - at nonmiscible displacement.

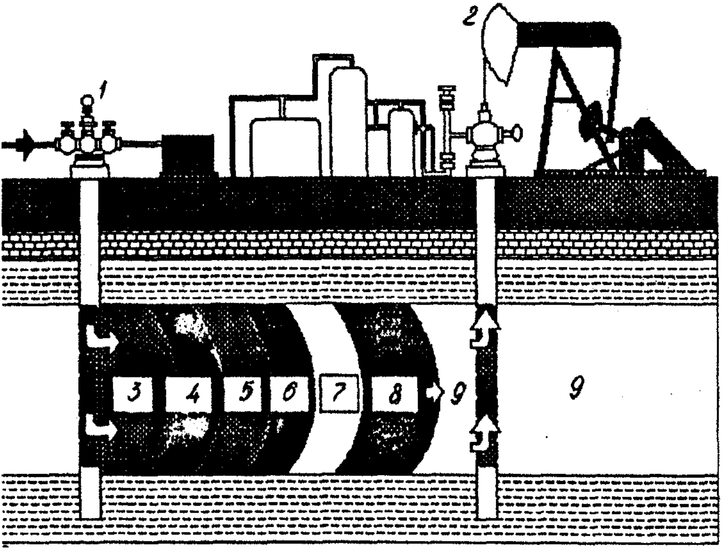

Fig. 2.22. Scheme of oil displacement by CO_2:
1- injection well; 2- producing well; 3- displacing fluid (water); 4- gas zone; 5- water zone; 6- gas zone; 7- miscibility zone; 8- oil bank; 9- zone of initial formation state.

The method of CO_2 injection is more desirable to be used in the fields with the occurence depth of about 7000 m at high formation pressure (above 13 MPa) and degree of drowning, with low oil viscosity.

The main technologies are:

- continuous CO_2 injection: injection of water saturated with CO_2 (up to 3 - 5 %) (carbonised flooding) (see Fig. 2.23);
- displacement by CO_2 plug (plug size is 0.1 - 0.3 of pore volume);
- alternating plugs of CO_2 and water to reduce fingering;
- cyclic injection of carbon dioxide and water;
- joint injection of CO_2 and surfactants.

The main problems in using CO_2 method are due to the availability of sources of obtaining CO_2 close to the field location, its transportation, as well as CO_2 separation from oil and its regeneration for further injection.

The examples of studying producing Triassic fields of the North Sea, Devonian the Volgo-Ural fields show that the injection of CO_2 into producing formations of sandstones and carbonate rocks changes the rock carbonate and clay content as well the porosity and permeability. Thus, in the reservoirs D_1 of the Romashkinsk and Sergeevsk fields the injection of CO_2 reduced the carbonate content twofold and the clay content by 15-70 %. In this case we could observe an insufficient increase of open porosity and a considerable increase of permeability by 75 %. The examples of producing formations of the North Sea fields reflect the appearance of solution channels in the rocks containing $CaCO_3$ thus resulting in the increased formation permeability and the changes of dissolved gas concentrations. Dissolution becomes more active at higher temperature. The process is greatly influenced by structural heterogeneity of rocks, while the presence of residual oil in pore space slows it down. Along with the positive action of CO_2 injection, there is initiated precipitation of asphalt-resin substances from oil which is in particular observed in the formations A3 of the Kozlovsk and B2 of the Rodayevsk fields. This precipitation reduced rock permeability and made oil recovery difficult. CO_2 injection into the formation is most desirable to be performed for the deposits with formation pressure of about 20 MPa and higher, that is, at the depths over 1000 m and in formations with relatively low viscosity - less than 5 MPa and with a small thickness up to 10-15 m.

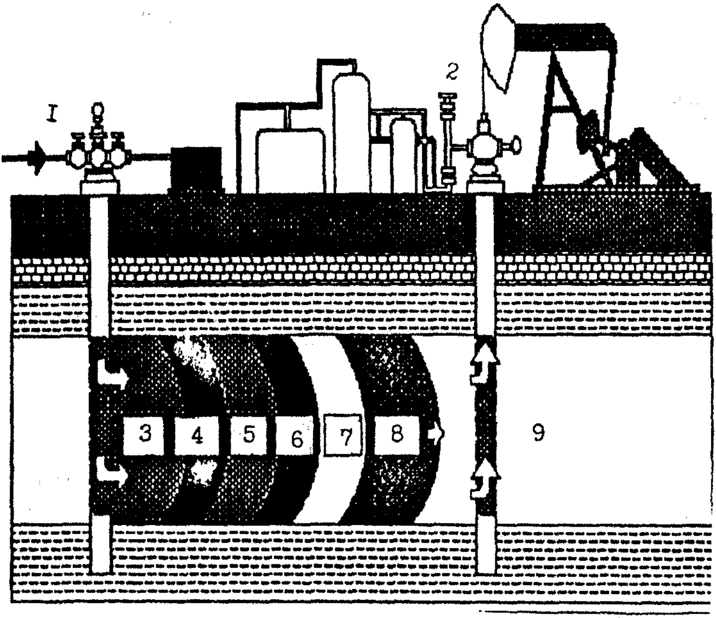

Fig. 2.23. Scheme of oil displacement by carbonised water
1- injection well; 2- producing well; 3- gas and water zone; 4- gas zone; 5- gas and water zone; 6- gas zone; 7- miscibility zone; 8- oil bank; 9- zone of initial formation state.

2.4.2. **Miscible hydrocarbon solvent injection**

Hydrocarbon solvent injection is basically used in flat reef deposits with carbonate type reservoir. The main geological criteria of successful application of the method is the formation depth occurrence and thickness. This is connected with the necessity of achieving definite conditions (namely, achieving minimum miscibility pressure of the agent and oil). Limitations in thickness mainly result from the necessity to provide a high formation permeability at considerable pressure and eliminate the breaking.

There are distinguished two basic technologies:
- horizontal (for flat deposits of large area);
- vertical (for reef deposits of large thickness or steeply dipping formations) [38].

Mainly vertical technology (about 80 % of all formations) is used in hydrocarbon solvent injections.

2.4.3. **Hydrocarbon (natural) gas and nitrogen injection**

Mechanism of oil displacement by hydrocarbon (natural) gases and nitrogen is basically similar to oil displacement by carbon dioxide [45]. At the same time there are some peculiarities. Thus, the conditions of complete mixing of gases with oil are achieved at higher pressures as compared with carbon dioxide. Hydrocarbon gas mixes with oil at pressures of the order of 25-35 MPa, nitrogen - at 36-50 MPa. In addition, nitrogen mixes with light oil easier than with heavy oil and poorly dissolves in water. As a result, the coefficient of oil displacement by nitrogen is lower than coefficient of oil displacement by natural gas and, moreover, by carbon dioxide (approximately by 4-7 %). (Fig. 2.24 represents oil displacement by nitrogen). The efficiency of non-miscible oil displacement by nitrogen and hydrocarbon gas is also lower than that of oil displacement by carbon dioxide. Oil recovery considerably increases if CO_2 is added to the injected natural gas nitrogen [17]. In gas deposits the amount of nitrogen may reach 25 % and it may be used in light oil field development.

Hydrocarbon gas is mainly used for the recovery of light oils and for further development of oil deposits after flooding. The efficiency of oil displacement by natural gas is higher, the more ethane-butane-propane

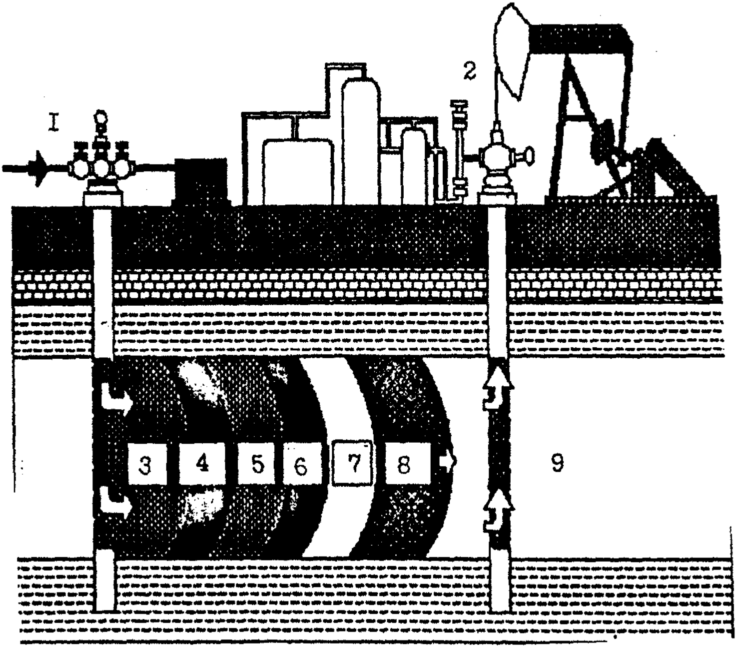

Fig. 2.24. Scheme of oil displacement by nitrogen:
1- injection well; 2- producing well; 3- water; 4- nitrogen; 7- miscibility zone; 8- oil bank; 9- zone of initial formation state.

components are included in the injected gas. Either petroleum gas, or gas of gas caps, or gas from gas fields may serve as a source for natural gas.

The injection of enriched gas mainly takes place in reef formations with light oil at considerable depths (from 2600 m and higher), with considerable oil thickness (over 50 m) and porosity over 0.07 unit fractions. This method is largely used as a secondary enhanced oil recovery method. In addition, WFLH (wide fraction of light hydrocarbons) is added into gas flow to reach a complete mixing of gas and oil.

The fringe volume in successful projects amounted to 35 - 40 % of pore volume, and due to application of the method additional oil recovery reached 12 - 30 % of the initial recoverable reserves.

Hydrocarbon gas injection is very favourable for development of reef and flat-seated deposits with light oil. The perspective of its application greatly depends on the prices for hydrocarbon gases and oil.

Combustion gas containing over 85 % of nitrogen, or nitrogen obtained from fractional pumping of a source for nitrogen. Combustion gas is obtained when natural gas is burnt in a steam boiler. It should be noted that in this case the volume of obtained combustion gas is 9 times higher than the volume of burnt natural gas.

2.5. **Microbiologie oil recovery method**

Microbiologie recovery methods (MRM) are such methods which use vitality of microorganisms (bacteria) directly in the formation intended for oil recovery.

The main oil displacing mechanisms using the MRM are:

- formation of bio-surfactants resulting in reduced interfacial tension at the interface of oil and water, oil and rock;
- formation of various acids which widen the pore channels of rocks;
- increased formation pressure - P_{form} due to liberation of gases N_2, CO_2, CH_4, H_2 by microorganisms;
- liberation of gaseous products tends to reduce oil and water mobility ratios because of increased oil mobility $\lambda = k_o/\mu_o$;
- changes in rock wettability.

Rozanova E.P. and Nazina T.N. draw attention to the following kinds of bacteria:
HCOB - hydrocarbon oxidizing bacteria which live in aerobic zone, that is, in the zone where oxygen exists;
FB - fermentation bacteria living in aerobic and anaerobic zone;
MFB - methane forming bacteria, which live in anaerobic zone, that is, in the zone lacking oxygen;
SRB- sulfate-reconcentration bacteria living in anaerobic zone;
MBRM- this process is multi-staged. In the zone of HCOB we can observe absorption of hydrocarbons contained in oil, and of oxygen. The products of HCOB vitality serve as nourishing medium for FB. Alcohols, H_2/CO_2, methane formed in the FB zone are partially absorbed by MFB. On the whole the scheme of vitality zones of microorganisms may be presented as it is given in Fig. 2.25.

Mechanism of microbial oil degradation (according to Davis, 1946). Hydrocarbons are decomposed by microorganisms and turn into fatty acids which, in their turn, may be used by microbes as food. Fatty acids accelerate the process of oil emulsification. The degradation rate depends of population of microorganisms. Degradation increases with population growth. Population growth of microorganisms is stipulated by extra nourishment in the kind of nonorganic nitrogen and phosphorus. The lack of nitrogen and phosphorus leads to the fact that bacteria eat other organic molecules but not hydrocarbons. By the way, bacteria distinguish about 6 million organic molecules and substances formed in living organisms. Professor Klod Zo Bell who introduced MRM for oil recovery pointed out that almost all hydrocarbons were oxidized under the influence of certain bacteria. He called these populations the polyfagecytose models which could oxidize a great number of oil fractions. Bacterial oxidation of mineral oil may reach 36-360 gr/1cu m annually (Oppengeimer K., 1989).

In time the location of bio-reactor and BHZ sweep may change. In this case the so-called «witch's rings» are formed. The zones of HCOB, FB, MFB, SRB may be conventionally called an area of bio-reactor (see Fig. 2.26 and 2.27). As this zone is small as compared with characteristic sizes of basic WSS elements, the characteristic period of microorganisms vitality is small as compared with the period of development of this element.

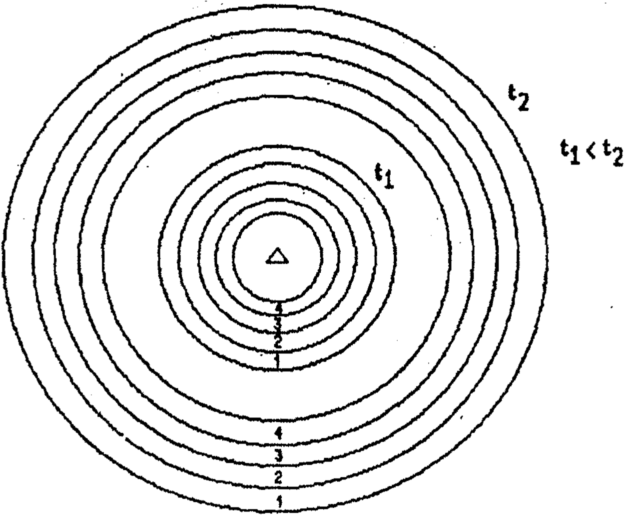

Fig. 2.25. Scheme of bacteria metabolites motion:
1- HCOB; 2- FB; 3- MFB, 4- SRB.

2.5.1. Bio-surfactant injection

The most spread bio-surfactants are emulsions, anion lypolysacharide (from the series of Acinctobacter).

Application of bio-surfactant injection method reduces surface tension on the water-oil contact (up to 1 mN/m). In this case the value of micellar formation critical concentration (MFCC) totals from 0.01 to 1.5 g/l. Bio-surfactant reduces oil viscosity by 95-98 % and increases its volume 2-3 times. Bio-surfactants are stable at high temperatures (up to 90 °C) and increased salt concentrations. Unlike the synthesized surfactants they are subject to bio decay, and it's very important from the point of view of economy and ecology. Bio-surfactant injection results in hydrocarbon emulsification, changes of hydrophobic surface properties, washing off of oil film from the rock surface. Bio-surfactant cost averages to 30 % of the cost of surfactants.

2.5.2. Biopolymer injection

Biopolymer injection increases the value of oil recovery factor due to

- increase of solution viscosity from 1000 mPa×c (hence, decrease of water and oil mobility ratio);
- decrease of phase permeability for thickened water;
- clogging of fractures and highly permeable zones.

Nowadays the following biopolymers are widely used: Ksantan, scleroglukan, polysacharid S-130, which are characterized by a higher stability in media with high salt concentrations and formation temperature, small adsorption, stability within a wide pH range, stability to mechanical and oxidation destruction as compared with chemically synthesized polymers. Biopolymers are formed by microorganisms. Biopolymers insufficiently degrade when injected. Biopolymers protect the latter from drying and the action of other microorganisms. For OFD the most important are non-cellar biopolymers such as Ksantan which forms microorganisms of the xanthomonas campestris family, and scleroglucan formed by sclerotium Glucanicunt fungus. Ksantans and glucans are obtained from ferment liquid as powder of high solubility and filtering. To prevent microorganisms mutation, the following regime should be observed. Glucans are obtained in lower concentration than Ksantans (up to 22 %).

Unlike the artificial polymers (PAA), the bio-polymers possess higher stability to multivalent ions of calcium and magnesium and their viscosity is higher, the higher is salinity. At lower salinity Ksantans are poorly formed, but at higher salinity the adsorption increases. Ksantan adsorption is high in the presence of clay minerals. At high pH values the Ksantan stability to magnesium and calcium salts reduces due to the presence of pyrovinograd acid. Molecular weight of Ksantans (1÷3 mln) insufficiency changes at high shear rates. Ksantans are not used in low permeable formations (≤ 0.005 mkm^2) and at temperatures > 70 °C. In the presence of oxygen and iron ions Ksantan decomposes. Biopolymers as well as polyacryl-amides may seam when VES is formed and salts of polyvalent metals are used.

2.5.3. Microbes injection with a cycling of food and melass flooding

Microorganism injections with a cycling of food as well as microbe (melass) flooding are intended for recovery of viscous oils (from 30 to 100 mPa×c). In this case oil displacement from porous media takes place due to the following mechanisms:

- changes of interface tension;
- generation of bio-surfactants;
- changes of capillar pressure;
- oil displacement from the depressed zones.

Microorganisms develop very well if the diameter of pores is twice more than the diameter of microorganisms. When microflora interacts with oil, the following organic acids (acetic, propion, oil); solvents (aldehydes, alcohols, acetone); methane, propane, CO_2, CO, N_2, H_2, H_2S are formed.

The melass flooding is mainly used for carbonate formation development (limestones, dolomites) due to considerable CO_2 volumes which can be obtained from microorganisms. The scheme of oil displacement at melass flooding is presented in Fig. 2.27; and at realization of method of formation microflora activization - in Fig. 2.26.

Location of microorganisms zones is reversible concerning the zones of metabolite motions (or propagations) (Fig. 2.25). It's connected with the fact that HCOB get the products (nitrogen, phosphorus, oxygen) necessary to maintain their vitality together with the flow of injected water. But both soluble and insoluble products of their vitality are washed away by water flow into the zone of formentation bacteria. Such products

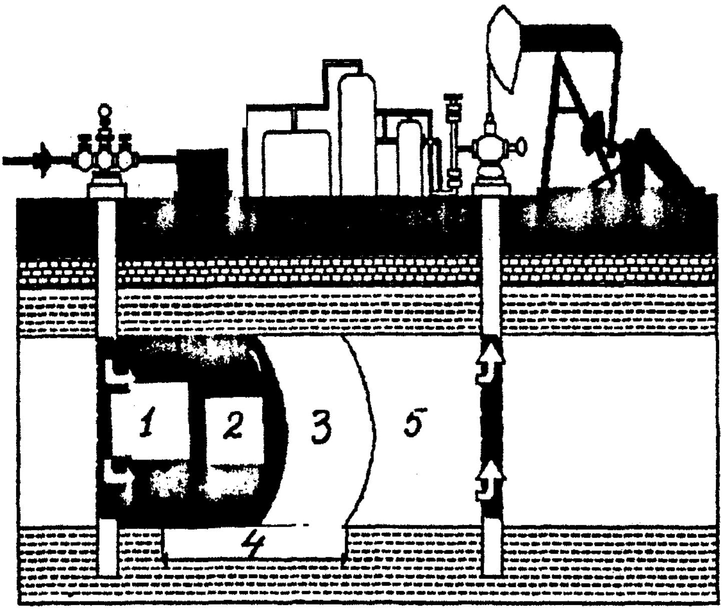

Fig. 2.26. Scheme of oil displacement at melass flooding:
1- water+melass; 2- HCOB; 3- FB; 4- bio-reactor; 5- zone of initial formation zone.

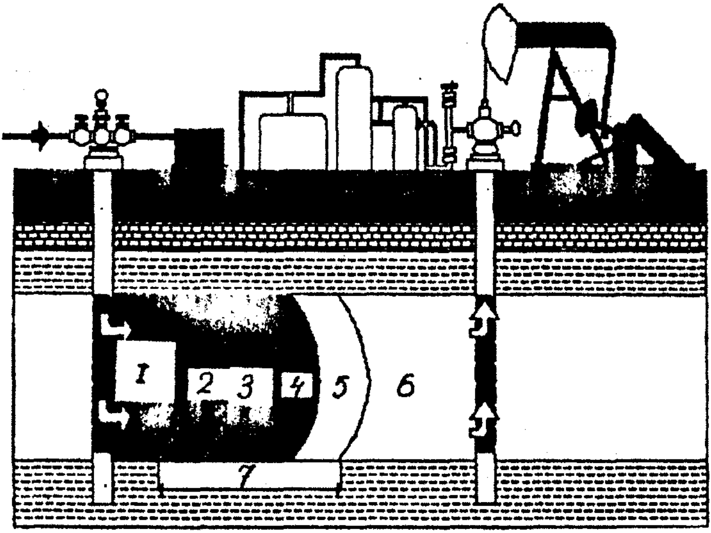

Fig. 2.27. Scheme of oil displacement in method of formation microflora activization: 1- water; 2- HCOB; 3- FB; 4- MFB; 5- SRB; 6- zone of initial formation state; 7- bio-reactor.

of FB as soda, carbonates, acetate and alcohols are food for MFB, while sulfates are a nurition medium for SRB.

The above method is characteristic of the method of natural microflora activization. As we can see from Fig. 2.27, in case of mellas flooding realization only 2 zones are formed: the zone of injected FB and the zone of joint development of MFB and SRB.

The microorganisms are very scrupulous in absorption of various hydrocarbon components which are contained in oil. For an equal period of time the microorganisms absorb various types of hydrocarbons in the following order in percent (according to a personal report of Ibatulin R.R.):

- paraffins - 90 %;
- asphaltenes - 8 %;
- resins - 2 %.

Consumption of lighter oil components may cause an opposite reaction in the development of microorganisms and finally may result in destruction of bacteria populations.

3. Criteria of applicability of oil recovery methods

Laboratory and further pilot tests on application of various recovery methods show the influence of various geologo-physical parameters of formation and formation fluids on their efficiency [10, 39, 48, 56]. The analysis of successful and unsuccessful results of the carried out work enabled to obtain intervals of values of various geologo-physical parameters at which the application of either recovery methods gave positive results (from the point of view of technological and economic effects). These values of geologo-physical parameters were called criteria of applicability of oil recovery methods (RM) [10, 22, 25, 27, 28, 30, 39, 42, 48, 56].

Geologo-physical parameters which influence the possibility and efficiency of application of either recovery methods may be subdivided into 3 groups:

1. Parameters which are changed neither by the formation area, nor in the development process. They present a reservoir type, occurrence depth of a producing horizon, thickness of the horizon, temperature gradient.
2. Parameters being changed by the formation area, but not being changed in the development process; mineral composition of fragmental part of terrigenous reservoirs, clay material and carbonate

reservoir rocks, thickness of a producing formation, its parting, sandy content and clay content of rocks, mineralization of formation waters, their salinity, density and viscosity of oils.

3. Parameters being changed both by area and section of a producing horizon, as well as during pool development. They include permeability of reservoirs, their porosity, oil and water saturation, gas saturation, hydrophobic and hydrophylic properties of pore space, reservoir pressure.

Thus, by the first group parameters we can reject RMs which can't be used due to limitations caused by these characteristics. By the second group of parameters within the formations we may single out the sections which contain limitations of applicability of either methods. The third group of parameters is desirable to design in time the change of one RM for the other in separate areas of the formation.

For each recovery method there exist its own criteria of applicability which are connected with peculiarities of thermal, physico-chemical processes occuring in the formation.

Thus, for example, thickness, permeability and occurrence depth are the basic parameters of thermal recovery methods restricting their application.

Gas methods application is restricted by such parameters as formation thickness, oil viscosity and formation pressure. The latter considerably influences the miscibility conditions of injected gases with formation oil.

For physico-chemical methods the basic restricting parameters are formation temperature, salinity and mineralization of formation waters. At high values of these parameters the destruction of molecules of a chemical reagent takes place thus reducing the effect of RM to a great extent.

In addition to geologo-physical characteristics restricting the application of separate recovery methods there exist a number of parameters considerably influencing the efficiency of application of these recovery methods.

Such parameters are as follows:

1. Reservoir fracturing. Restriction of the amount of this parameter is connected with a quick breakthrough of expensive working media

through the fractures to the producing wells, thus resulting in low sweep efficiency and a negative influence on the process.

2. Availability of gas cap as well has a negative influence due to a considerably higher permeability of gas-saturated section of the formation where the crossflow (of the formation where the crossflow) of the working agents takes place.
3. Reservoir oil saturation. Restriction by this parameter is usually connected with RM economic efficiency as at a low value of oil saturation (<25 - 30 %) a considerable part of working agents is spent on the oil saturated section of the reservoir.
4. Oil viscosity. This parameter is one of the most considerable ones. Thus, application of thermal methods is the most efficient for viscous and high-viscous oils (over 50 mPa×s), while application of PCh RM is limited by values of 25-30 mPa×s (for polymer flooding - 100-150 mPa ×s).
5. Reservoir clay content. For all recovery methods a maximum value of this parameter is limited by 10 % because of either reduced reservoir permeability due to swelling of particles or greater adsorption of chemical reagents.
6. Occurrence depth of the production formation which causes technical complications because of necessity in more powerful compressors to provide high injection pressures. To inject thermal carriers into the formation when thermal recovery methods are used, one should take into account the loss of heat on the way from the compressor to the formation as well. Most of the authors limit this depth by 1.2 - 1.5 km. Reservoir occurrence depth is closely connected with thermodynamical parameters which can also restrict application of EORM.
7. Reservoir thickness restricts the possibility of RM application, here existing both maximum and minimum applicability limit from 2 to the first tens of meters. The reservoir with thickness less than 2 m isn't practically influenced by external effects, while at 10-20 m there may be breakthroughs of working media both along roof and bottom sections of the reservoir.

3.1. Classification of applicability criteria

Here we enclose the following classification of applicability criteria groups which resulted from consultations with a wide range of specialists from IPNG RAS and SOGA named after I.M. Gubkin in the field of geology, oil field development, oil chemistry and reservoir physics.

The applicability criteria include:

1. Rock characteristics.
2. Reservoir characteristics.
3. Formation oil characteristics.
4. Formation water characteristics.
5. Formation gas characteristics.
6. Formation matter characteristics.
7. Petrographo-mineralogical rock content.

In its turn each group of applicability criteria is subdivided into constituent parameters:

1. Rock characteristics:
1.1. Rock type (terrigenous, carbonate, pyroclastic.
1.2. Reservoir type (porous, fractured, mixed).
1.3. Permeability, mcm^2.
1.4. Porosity, unit fractions.
1.5. Initial oil saturation, unit fractions.
1.6. Residual oil saturation (after depletion drive or waterflooding development), unit fractions.
1.7. Initial gas saturation, unit fractions.
1.8. Interstitial water content, unit fractions.
1.9. Average contact angle (hydrophilic and hydrophobic reservoir), degree
1.10. Middle diameter of grains, mcm

2. Rock characteristics:
2.1. Total thickness, m.
2.2. Effective oil-saturated thickness, m.
2.3. Thickness of oil saturated zone, m
2.4. Thickness of gas-saturated zone, m
2.5. Thickness of overlying interlayer, m.
2.6. Formation pressure, mPa.
2.7. Formation temperature, °C.
2.8. Parting, unit fractions.
2.9. Sandy content, unit fractions.
2.10 Average angle of rock dip, degrees.
2.11. Depth of top occurrence, m.

3. Formation oil characteristics:
3.1. Formation oil density, kg/m^3.
3.2. Formation oil viscosity, MPa ×s.
3.3. Content of fractions boiling out at $t<300$ °C.
3.4. Content of fraction boiling out at $t>300$ °C.
3.5. Acid number, mg OAO/g.

4. Formation water characteristics:
4.1. Formation water density, kg/m^3.
4.2. Formation water viscosity, mPa ×s.
4.3. General salinity, g/l.
4.4. pH value, unit fractions.
4.5. Chloride anion content (Cl), g/l.
4.6. Sulfate anion content, (SO_4), g/l.
4.7. Bicarbonate anion (HCO_3) g/l.
4.8. Carbonate anion content (CO_3), g/l.
4.9. Potassium and natrium cations content (Na+K), g/l.
4.10. Magnesium cation content (Mg), g/l.
4.11. Calcium cation content (Ca), g/l.

5. Formation gas characteristics:
5.1. Formation gas density, kg/m^3.
5.2. Formation gas viscosity, mPa×s.
5.3. Mass content of C_2-C_6 in gas, unit factions.
5.4. Nitrogen content , unit fractions.
5.5. Oxygen content, unit fractions.
5.6. Carbon oxide content, unit fractions.
5.7. Carbon dioxide content, unit fractions.
5.8. Sulphureous anhydrite, unit fractions.
5.9. Hydrocarbon content, unit fractions.
5.10. Hydrogen content, unit fractions.
5.11. Methane content, unit fractions.

6. Formation matter characteristics.
6.1. Paraffin content, unit fractions.
6.2. Asphaltene content, unit fractions.
6.3. Resine content, unit fractions.
6.4. Gypsum content, unit fractions.
6.5. Surfur content, unit fractions.
6.6. Iodine content, unit fractions.
6.7. Bromium content, unit fractions.
6.8. Borium content, unit fractions.
6.9. Ammonia content, unit fractions.

7. Petrographo - mineralogical rock content:
7.1. Quartz content, unit fractions.
7.2. Field spar content, unit fractions.
7.3. Fracture content, unit fractions.
7.4. Cement content, unit fractions.

7.5. Content of non-swelling (caoline) clays, unit fractions.
7.6. Content of swelling (montmorillonite) clays, unit fractions.

The enclosed classification of applicability criteria is the most complete and at the same time it includes considerable parameters which influence the application of various recovery methods.

The given structure of criteria served as the basis to form the data base in personal computers.

The table [3.1.] of applicability criteria has been made up with account of the data available in literature on each parameter according to expert's evaluations published by the authors previously [23, 27, 42].

When choosing the recovery methods one should know the extreme values of geologo-physical and filtration - volumetric parameters. The given extreme parameters are used to build the belonging function.
Further a brief summary of the parameters and specific features of their influence on the performance of various recovery methods is given. The description of the parameters, as a rule, doesn't include the definition, main types of classification, ranges of changing parameters (characteristic of the tasks of oil field development), mechanisms and particularities of the influence of these parameters on various RMs.

3.2. Rock characteristics

Rock types

Generally accepted rock classification is the following:
- terrigenous;
- carbonate;
- clay shales;
- vulcanogennosedimentary.

Type of the rock is one of the determining parameters of a successful realization of hydrodynamic and physico-chemical recovery methods. Thermal and gas methods are practically not used in cavernous and fractured rocks.

The process of silicate dissolution in sandstones of porous rocks which is the results of alkaline injection has an irreversable character. In this case silicon concentration increases from 2 to 12 mg/g, and it may increase to 1900 mg/g when temperature rises. Solubility of silicates results in caving-in of wells and in increased sand showing. On the other hand, alkaline-silicate solution increases sweep efficiency [16].

When CO_2 is injected, carbonates may dissolve in water containing CO_2. The higher the injection pressure is, the higher the solubility of carbonates is, especially in the bottom-hole zone [17].

Reservoir type

There exist the following types of reservoirs:
- porous;
- cavernous;
- fractured
- mixed.

In gas injection the availability of a fractured reservoir is an unfavorable factor due to the premature gas breakthrough to the producing wells.

Vertical gas displacement of oil is mainly preferable in fractured reservoirs [19].

In the development of light oils incremental produced oil volume may reach 8-12 %.

In fractured reservoirs with good imbibition of porous blocks an increased rate of oil-water contact (OWC) results in water breakthrough to the producing well along the fractures and in oil losses, respectively [30].

Plugging of fractures and highly permeable zones of reservoirs may take place when polymer solutions are injected due to the ability of polymer to coagulate in the formation. So polymer injection is followed by injection of the solutions of the following agents: chrome and aluminium ions. It results in formation of viscous gels. Thus, 1 kg of PAA without a coagulating solution gives on average 0,7 t of oil, while 1 kg of PAA with coagulating solution gives 4 t of oil.

Permeability

Permeability of porous medium means an ability of this medium to transmit fluids (liquids and gases in the presence of pressure drops). Permeability of commercial oil and gas reservoirs ranges from 0.0001 to 20.0 mcm^2. However, permeability of the majority of fields is less than 0.5 mcm^2 [14]. Reservoir classification by permeability

- low-permeable < 0.01 ÷ 0.3 mcm^2;
- medium-permeable 0.01 ÷ 0.1 mcm^2;
- high-permeable > 0.1 ÷ 5 mcm^2.

Pebbles, coarse-grain sands, fractured limestones possess the best permeability among rocks. Average value of permeability for most of the reservoirs ranges from 0.05 to 0.5 mcm^2 [32].

Steam injection may reduce permeability of porous medium because of precipitation of solid residue from the asphalt-resin substances [10].

In-situ combustion may result in reduced permeability of porous medium at simultaneous increase of its specific surface causing, in its turn, an increase of the amount of fuel burning in the formation [34].

Low-concentration alkali injection results in a considerable decrease of permeability at clay content of 15-20 %, while an increase in alkali concentrations results in a permeability increase surpassing permeability to water [16].

The development of oil-saturated reservoirs with the permeability of less than 0.005 mcm^2 is rather difficult because of the restriction by water injection rate. Thus, the development of such reservoirs may be performed either by continuous gas injection or by gas fringe injection followed by its pumping by cheaper gases [29]. It's not recommended to inject biopolymers into such reservoirs.

Porosity

Porosity means an effective (open) porosity, that is the ratio of connected supercapillar, capillar and subcapillar pores to the total rock volume. Porosity in oil and gas deposit usually ranges from 0.001 to 0.50 unit fractions [14].

They distingnish [32]:

- **absolute porosity** which includes all rock pores (disconnected and interconnected voids);
- **effective porosity** which includes only interconnected voids.

By their sizes the pores are classified into:

- supercapillar, d>0,5 mm;
- capillar, d=0,0002+0,5 mm;
- subcapillar, d<0,0002 mm.

In subcapillar pores the fluid can't move under the action of natural force. Porosity variants by lithological rock types (in unit fractions) [14]:

- Sandstones - 0,12-0,30 unit fractions;
- Sands - 0,18-0,4 unit fractions;
- Aleurites - 0,3-0,4 unit fractions;
- Carbonates - 0,03-0,3 unit fractions;
- Clay shales - <0,015 unit fractions;
- Clays - <0,50.

According to A.A. Chanin a complete porosity of sandstones and aleurites is over 5-6 % open, while for sands complete and open porosities practically coincide.

Oilsaturation

Oilsaturation So means ratio of oil volume contained in the open pore space to the total pore volume: $S_o=V_o/V_{por}$. Reservoir classification by oilsaturation:

- high oilsaturation - >0,8 ;
- average oilsaturation - 0,6÷0,8;
- low oil saturation - <0,6.

The higher oil saturation is the lower (by the order) is the loss of alkali in sedimentary rocks [18]. The increase of temperature from 20 °C to 150 °C characteristic of thermal recovery methods increases residual oil saturation from 45-25 % to 18-12 % [10].

There has been achieved a statistical dependence of residual oil saturation reduce from 42 % to 9 %, at increased WPD from 0.1 to 25 ac /well for the in-situ combustion process.

Content of connate water

Connate water means water contained in rock voids which can't be displaced under conventional conditions of oil displacement. In oil and gas deposits the saturation of connate water ranges from 0.01 to 0.7 unit fractions [14].
In most of oil and gas-bearing basins the depth of water occurence at which the temperature is close to critical (364 °C, at higher t° the water can't remain in a liquid state) is equal to 10-12 Km. Hence, connate water is present in all oil and gas deposits. The content of residual water in clay sandstones, aleurites, thin-porous sandstones may reach 70 %. In sandy - aleurite reservoir of oil the residual water occupies 10-30 % of pore volume.

We distinguish the following types of connate water [14]:

- loose-connate water. In forms the upper layer of the connate water surface;
- connected water is found on the contacts between grains;
- adsorption water which forms the internal layer of connate water. The thickness of this layer is several molecules. This water is retained on the rock surface by a very high pressure up to 1000 MPa, it doesn't dissolve liquids and gases, and has density over 1000 kg/m^3 and the freezing temperature - 78 °C.

Average contact angle

Definition. Contact angle θ characterizes the degree of wetting and is equal to the angle formed between a hard surface and the tangent to the drop surface in the point of its contact with a solid body.

By Sh.K. Gymatudinov the rocks containing S_{cw}=0.1 should be referred to hydrophobic rocks, and at S_{cw}>0.1 the rocks should be considered hydrophilic.

If the contact angle θ changes from 0 to 90 °C, the liquid wets the rock surface and rock is hydrophilic.

If the contact angle changes from 90 to 180 °C, the liquid doesn't wet the surface and the rock is hydrophobic.

At θ=90 the surface possesses a neutral wettability

The value of the contact angle makes it possible to judge the relation of the interfacial tension on the interface and is determined by the ratio

$$\cos\theta = \frac{\delta_{os} - \delta_{ws}}{\delta} \qquad [29],$$

where δ - is an interfacial tension on the boundary surface «water-oil» . δ_{os}-δ_{ws} - interfacial tension on the boundary surface «oil-rock» and «water-rock», respectively.

Contact angle of sedimentary rocks mainly depends on the chemical content of rock surface.

When t° increases from 20 °C to 150 °C, the contact angle reduces from 35-45 °C to 15-25 °C [14]. The less the surface tension is, the better the liquid wets the body. The surface tension on the boundary of formation waters with oil ranges from 1×10^{-3} nM/m for alkali water to $20\div33\times10^{-3}$ nM/m for hard and fresh water. Oil recovery in flooding increases when filtration rate in hydrophobic formations grows due to compensation of forces counteracting the oil displacement by water [30].

In micellar flooding (with external water phase) sorption of surfactans in hydrophilic medium occurs quicker than in hydrophobic medium [25]. However, water micellar solutions exhibit surfactant sorption oftener. The nature of wetting the surface of sedimentary rocks is connected with the presence of polar components in oil which adsorb on the rock surface and hydrophobize it. The injection of alkali water solutions results in decreased flooding by 9÷17 % due to the ability of alkali to hydrophylise the surface [18]. Application of the method of injection of water surfactant solutions reduces the contact angle [5].

3.3. The reservoir characteristics

Effective oil-saturated thickness

The effective oil-saturated thickness is the thickness equal to the total thickness of layers made up by producing oil and gas-saturated reservoirs. In the limits of OWC the effective and the effective oil-saturated thicknesses coincide [32].

The formation thickness is usually subdivided into:

- total thickness (the difference of the occurrence depths of rock roof and bottom;

- effective thickness (the difference between total thickness and non-reservoir interlayer thicknesses);
- effective oil-saturated thickness (outer oil-saturation contour is a line of zero effective oil-saturated thickness).

This parameter has a considerable effect on the successful application of gas methods. The effective oil-saturated thickness must be large enough to prevent fracture of the formation at high pressures [60]. Gravitational gas segregation is possible in powerful oil-saturated layers [17]. To prevent the gravitational segregation in CO_2 injection, it's necessary to use either alternating CO_2 and water injection or well pattern density, or CO_2 injection into the roof of the formation and oil displacement (to the bottom) downwards. In steam thermal stimulation the total effective thickness shouldn't exceed 25 m and 20 m in in-situ combustion [13].

Thickness of water-saturated zone

Water-saturated zone is a transparent zone where oil saturation increases from 0.00 to a certain amount (usually 0.5+0.6). The thickness of water-saturated zones depends on natural capillar phenomena and for various lithological rock types it changes from 0.5 to 16-7 m.

There are distinguished 5 zones by saturation:

- purely gas-bearing zone;
- gas-oil;
- purely oil;
- water-oil;
- purely water bearing zone.

The higher the thickness of water saturated zone is, the more its negative effect on the process of steam injection is, especially with high oil viscosity. At a considerable thickness of bottom waters thermal losses are great, and the availability of a thin water-saturated layer is rather favorable (higher heating of oil-saturated zone at the expense of high heat conductivity of water) when steam is injected into the layer [49]. Activization of a perimeter resulting in breakthrough of these waters to the withdrawal zones is unfavourable for the in-situ combustion method.

Thickness of overlying rocks

Any rock can practically serve as an overlying rock for oil and gas-bearing reservoir on condition it's completely impermeable for movement of fluids.

The basic types of overlying rocks are: clays and argillitous rocks (sandy clays, clay shales, etc), the other types are: pure limestones, chalk, sandy limestone, strongly cemented sandstone, quartzites.

The covering rocks are characterized by: low permeability < 0.0001 mkm^2; very thin grain content; small size of pores; water-saturation; capillar pressure which resists the fluid filtration through the cover. Permafrost rocks are also good covers.

The availability of overlying aleurotile (clay) rocks is rather favorable for a steam injection method as in this case the restriction of vertical steam migration takes place. With the thickness of overlying rocks over 3 m the vertical migration is completely eliminated [49].

In in-situ combustion a considerable thickness of overlying rocks causes gryphonoformation due to the escape of air into the overlying formations [31]. The maximum thickness of joints between the neighboring oil-saturated layers united into one production formation [30] shouldn't exceed 10 m. Otherwise thermal interference between the layers reduces and so does the total thermal efficiency of the process [13].

Formation pressure

Formation pressure P is a pressure of formation fluids (water, oil, gas), saturating sedimentary rocks. It is similar to hydrostatic and hydrodynamic pressures. In water-bearing formations connected with the surface the formation pressure is hydrostatical. In closed reservoirs the formation pressure is influenced by the processes of cementation, mineralization (which results in decreased porosity) as well as thermal hydration which increases water content in a pore space.

Usually formation pressures are measured with depth for a hydraulic gradient which is from 0.97 to 1.24 MPa for the depth of 100 m depending on the salt content and fluid density.
Formation pressures by the hydraulic gradient are distinguished as:

- lower formation pressure < 0.97 MPa/100 m;
- normal formation pressure 0.97-1.24 MPa/100m;
- abnormally high formation pressure > 1.24 MPa/100m.

Change in the formation pressure slightly influences the thermal properties of rocks [21]. This parameter is extremely important for a successful realization of gas and thermal methods.

The highest heat of steam formation is achieved at low formation pressures, so in the formation with high pressure the steam injection method is not used, while the method of hot water injection is applied [47].

At pressures of 30-40 MPa the nitrogen solubility may reach 35-45 m^3/m^3 for light oils and up to 15-25 m^3/m^3 for heavy oils [53]. However carbon dioxide is mixed with oil at $P > 8\text{-}12$ MPa, and hydrocarbon gas - at $P >$ 25-35 MPa.

Formation temperature

Starting with its neutral level (usually 8-40 m from the surface) the formation temperature evenly changes with the occurrence depth and is characterized by a geothermal gradient and stage. The geothermal stage characterizes the rock occurrence depth interval in m at which the temperature increases by 1° C.

Usually this parameter varies from 10 to 35 m/°C. The geothermal gradient shows by how many degrees the formation temperature changes in case the occurrence depth increases by 100 m. It usually changes from 2 to 10 °C for 100 m. The average geothermal gradient value for oil and gas occurrence amounts to 2.7 °C for 100 m. Thermal and temperature conductivity of dry rocks drops at higher temperature , while thermal capacity increases. The decrease of temperature conductivity doesn't exceed 20 % of its initial value under normal conditions when temperature increases from 20 to 200 °C. The thermal capacity of rocks increases when the temperature increases approximately by 1.5-2 % for each 10 °C [21].

The formation temperature of many oil fields doesn't exceed 150 °C. In residual masses the temperature was registered to 200 °C [14]. The higher the formation temperature, the less the interfacial tension in oil-water system is, while rock wettability increases [10].

Alkaline solution injection into the formation results in dissolution of sand silicates which increases from 1.6 to 1930 mg/g at simultaneous pH growth from 7 to 12 when the temperature rises from 23 to 266 °C.

If the temperature increases, the size of ionogenous surfactant micella decreases, while that of non-ionogenous increases [46].

At other equal conditions the efficiency of CO_2 injection will be higher, if the formation temperature is lower (less than 120 °C) [29].

We may classify the oil and gas deposits by the value of the geothermal gradient in the following way:

- with abnormal low formation temperature of 0+2 °C/100m;
- with normal formation temperature of 2+5 °C/100m;
- with abnormal high formation temperature >4 °C/100m.

At increased temperature the rate of polymer dissolution in water increases and polymer adsorption on the rock skeleton decreases. At high formation temperature (80+120 °C) PAA quickly hydrolyses and precipitates (65) as calcium and magnesium polyacryl salts. The completeness and rate of polymer dissolution in water shows the efficiency of polymer flooding, so it's desirable to use them in the temperature intervals from 5 to 70 °C. At high temperatures (>70 °C) the thermal stability of biopolymers (ksantans and glucans) reduces [29].

Angle of dip

Gas methods (vertical technology) are mostly efficient in steeply dipping formations (with the angle of dip over 5°) [38]. In steam injection method in steeply dipping formations (at the angle of dip over 10 °) the producing wells should be located up-dip to the injection ones [66].

Formation occurrence depth

The occurrence depth means the upper border of the producing formation, namely, the occurrence depth of formation roof.

The main oil and gas fields are confined to the depths from 100 to 8000 m and oil fields - from 100 to 5.0 km with rather an irregular spreading along stratigrapic subdivisions: cretaceous deposits cover 30 % of all oil reserves; neogenous - 14 %; paleogenous - 70 %, devonian - 5 %.

The occurrence depth is one of the main factors influencing a successful application of gas methods. It's due to the fact that at higher occurrence depth the formation pressure increases, its importance being very significant. Each gas method possesses its own minimum pressure of agent miscibility with formation oil [38]. At occurrence depth less than 600 m the condition of intersolubility [17] is not provided for CO_2 injection method. The method of hot water injection, rather than steam injection, is used in the development of deep-lying formations by heat carrier injection into the formation under great pressure [10].

3.4 Characteristics of formation oil

Formation oil density

Formation oil density (pH) is a mass of particles for a unit of space volume occupied by it and it reflects chemical composition of oil. Oil density increases with the increase of the share of heavy hydrocarbons, asphaltenes, resins, paraffins and sulphur.

The density decreases when the temperature increases, that is, it depends on the occurrence depth. The unit of measuring density is (ML^{-3}). But you shouldn't confuse the formation oil density with the formation oil specific gravity. Specific gravity is characterized by the ratio of formation oil weight force to the unit of pore space volume occupied by oil.

Classification of formation oil by density (Kg/m^3) [43]:
- low-density - 600-820;
- medium - 820-900;
- heavy - 900-1000;
- extra-heavy - 1000-1100.

For in-situ combustion the concentration of burnt fuel increases from 14-15 to 22-25 Kg/m^3 .In case the formation oil density increases from 850 Kg/m^3 to 975 Kg/m^3 [46]. The density of most fluids decreases at lower temperature excepting the water which expands at temperature lower than 4 °C.

Formation oil viscosity

Formation oil viscosity characterizes the degree of formation oil resistance to form change at a final filtration rate.

Classification of formation oil viscosity accepted by the 7th World Oil Congress in mPa ×s [8, 43]:
- low-density - 0.01-5000;
- medium - 50.0-1000.0;

- heavy - 1000.0-10000.0;
- extra-heavy - > 10000.0.

The viscosity of formation fluids is higher than the viscosity of formation gas, that is, formation gas molecules travel over large distances without considerable obstacles from the other gas molecules, hence the resistance to their flow in the formation is not large. While flowing relatively to each other, the formation fluid molecules undergo reciprocal collision and sticking (adhesion). Formation oil viscosity is known to decrease at high temperatures. The unit of measurement of formation oil viscosity is the relation of strength unit to area unit and to unit of velocity gradient - (ML^{-1} T^{-1}). A generally accepted unit of fluid viscosity measurement in OFD is mPa×s.

2 types of formation fluids are distinguished:
- Newtonian;
- non-Newtonian.

Newtonian fluid is a non-compressible fluid which is governed by the linear law of Newtonian viscous flow $\tau = \mu \frac{\partial W}{\partial Y}$.

Non-Newtonian fluid is a non-compressible fluid with a constant internal friction (not resisting the flow) the initial shear shift of which is equal to zero (unlike the ideal fluid which isn't exposed to internal friction and with resistance to flow equal to μ=const). The dynamic viscosity at constant temperature is a constant. Water possesses the properties of Newtonian fluid.

Rheology as a science studies Newtonian fluids, i.e. those fluids which do not depend on the Newtonian law of viscous flow. There are fluids the μ-dynamic viscosity of which changes depending on the applied shear stress and velocity gradient $\frac{\partial W}{\partial Y}$. Non-Newtonian fluids are called rheological, abnormal fluids.

Non-Newtonian fluids are able to form intermolecular bonds and they usually have a high molecular weight. Strictly speaking, formation oil is a non-Newtonian fluid. Most mathematical models of oil displacement from porous media admit, for the sake of simplicity, that its behavior is ruled by the Newtonian law of viscous flow. However, its an extremely strong assumption.

Formation oil molecules are molecules with a large molecular weight and an irregular structure. Fluid flow in porous medium forms a row of molecules. In this case the occuring break of bonds depends on the applied force and within some period of time the fluid flow velocity increases while viscosity decreases.

The force caused by friction and viscosity of formation fluids act in the direction apposite the pressure. Thus they balance the pressure force.

The boundary layers are formed on the boundary of formation fluid and the rock where the formation fluid molecules stick to the rock surface (the so-called «absorption phenomenon»). The drop of flow velocity and the increase of shear stress due to viscosity take place in the boundary layer Non-Newtonian fluids are subdivided into:

- Bingham (viscous - plastic) fluids which are characterized by a constant viscosity, but for plastic fluids initial force should be applied in order to start their flow;
- dilutant fluids. At tangential shear stress these fluids show the tendency to expansion (dilutation is a process of expansion at deformation);
- pseudo-plastic (thixotropy is a process of reversible dilution).

Some time after the applied load such substances completely restore their initial properties.

The analysis of realization of numerous oil field development projects by five main EOR methods: steam injection, in-situ combustion, CO_2 injection, polymer injection, micellar - polymer flooding showed stable tendency to an area decrease falling on one well when formation oil viscosity increases [11]. The formation oil viscosity, rather than permeability, has a considerable influence on the maximum rate of oil reservoir development. The development rate decreases when viscosity increases.

Concentration of burning fuel (one of the most important parameters of WB process) increases with oil viscosity growth due to increased content of asphaltenes and resins as the coke formation is determined by the availability of these components. When steam and hot water are injected, the heating of viscous oil increases its mobility, but at the same time there appears a possibility of pore bridging when heated oil comes into contact either with colder oil or with reservoir. So the reservoirs with viscosity of 50-8000 mPa×s[10] are developed more frequently.

In CO_2 injection formation the more oil viscosity decreases, the higher its initial value is because of oil «swelling» under the influence of dissolved gas [17]. When the temperature increases, the fluid viscosity reduces faster.

Mass content of fractions boiling out at t° < 300 °C and > 350 °C

Oil is classified by mass fraction content in the following way:

Table 3.2. Classification of oils by mass fraction content

Mass content of fractions boiling out at	low-density	Medium	heavy
t <300 °C	50	30	20
300 °C < t< 350°C	30	50	20
t > 350°C	20	30	50

In thermal recovery methods heavy fractions of oil form highly - resistant water-oil emulsions. In the presence of oxygen in water or water steam the most probable reason for emulsion formations is the formation of surfactant molecules when molecules of heavy hydrocarbons oxidize. The higher in the temperature, the higher oxidation is [10]. Due to extraction of light oil components, steam injection may cause hard, very viscous hydrocarbon residue with high molecular mass thus resulting in the decrease of pore space permeability [10]. Light fractions of oil dissolve in injected CO_2 (or other gases) in case of miscible displacement, then they are caught up by fluid and transferred along the displacement [6]. If mass content of light hydrocarbons is great, better reciprocal oil and gas solubility is achieved.

Acid number (content of organic acids in oil)

The amount of caustic potassium (OAO) in mg necessary for neutralization of 1gr of oil is called **acid number**.

Usually acid number ranges from 0 to 10 [16]. Interfacial tension reduces if acid number decreases, but correlation dependence is very weak. Acid number is used in oil classification according to interaction activity with the caustic potassium solution (see Tab. 2.4).

3.5. **Characteristics of formation water**

General mineralization of formation water

A summarized amount of ions, salts and colloids is accepted as general mineralization.

Classification of formation water by mineralization in g/l [14]:
- poorly mineralized (fresh) water - 0.0-1/0;
- mineralized - 1.0-50.0;
- highly mineralized (brines) - 50.0-210.0.

Mineralization changes with the depth and way reach 300 g/l.
Formation water with mineralization up to 100-150 g/l doesn't contain sulfates. In case the deposit contacts the layers of gypsum and anhydrites, highly mineralized brines may be enriched with sulfate in the amount of 200-300 mg/l (0.2-0.3 g/l). There are also found brines containing up to 700 g/l salts [14].

The major ions contained in formation waters are the following 3 anions: chlorine (Cl), sulfate (SO_4^{2-}), hydrocarbonate (HCO_3^-) and 3 cations: natrium (Na^+), calcium (CA^{2+}) and magnesium (Mg^{2+}) [14]. In addition to them carbonate - ion (CO_2^{2-}); potassium ion (K^+), iron ions (Fe^{2+}) and (Fe^{3+}) are widely spread. The other elements occur in small amounts and are called low-component ones: bromide ion (Br^-), iodine ion (I^-), aluminium ion (NH_3^+), lithium ion (Li^+); strontsium (Sr^{2+}) and others.

An increased mineralization of formation waters has a negative effect on micellar - polymer flooding [57]. A high mineralization (over 1g/l) of water phase in the emulsion type «oil in water» results in its transformation into «water in oil» and its fast destruction [18].

The affect of mineralization on polymer injection is very complicated and depends on the properties of porous medium, formation water, polymer itself, etc. Generally, increased mineralization results in reduced solution viscosity thus damaging the efficiency of polymer flooding. At the same time relative permeability for polymer solution reduces. It results in enhanced oil recovery due to additional washing oil by water in low-permeable pores and porosity. If the method of water polymer solution injection is used from the beginning of the development, a ridge of highly mineralized formation waters may be formed in front of the polymer fringe. It may result in destruction of polymer solution structure. Solubility of phosphate trinatrium in mineralized water is limited [29].

pH value (active reaction of medium)

Alkaline-acid properties of formation waters which are determined by the concentration of pH ions H^+ and are expressed through value degree of this concentration and denoted as pH, i.e., $pH=-\lg C_h^+$, where C_h^+ is a concentration of hydrogen ions are called an active reaction of medium.

Classification of fluids by pH value [14]:
$pH<7$ - sour waters;
$pH=7$ - neutral waters;
$pH>7$ - alkaline waters.

When alkaline solutions are injected, the solubility degree of silicates in sandstones increases if pH increases from 7 to 12 and 5-6 times. This results in formation of alkaline - silicate solutions thus providing an additional oil recovery due to increased sweep efficiency factor [16] Ion concentration of hydrogen H^+ in formation water depends on the content of carbon dioxide and hydrolyzed salts of heavy metals in water.

Hydrogen ions may be bound by anions of weak acids. Then there appear an excessive amount of hydroxile OH^- ions which add alkaline reaction to the formation water, i.e. $pH>7$. And on the contrary, in the presence of weakly based cations the concentration of hydroxile ions OH- will decrease while of hydrogen ones, will increase, i.e., formation water will have an acid reaction ($pH<7$).

At increased pH the polymer solubility rate increases [29]. Polymers on the basis of cellulose are considerably stable at $pH\geq6$ and are not sensitive to shear rate. At $pH\leq6$ the polymers are quickly hydrolyzed. Both polymers and biopolymers are unstable to the salinity at high pH values.

Salinity

Salinity (hardness) of formation waters means the availability of alkaline - land metals - calcium and magnesium in it.

Hardness of water is determined by the content of calcium and magnesium in mg/l or in degrees. Each degree is equal to 10 mg/l of CaO. Usually the following types of formation waters in degrees are accepted [14]:

- soft formation water - < 10;
- medium - 10-20;
- hard - 20-30;
- very hard - >30.

Water hardness ranges from 0 to 100.

When cations Ca and Mg begin to react with alkaline solutions, they form poorly-soluble precipitation. Precipitation decreases permeability of washed out zones and increases the sweep efficiency. The icreased water salinity results in greater alkali losses [18].

At higher salinity the hydration of polymer groups reduces and thickened water viscosity considerably decreases. An increase in concentration of calcium and magnesium cations results in higher polymer adsorption on the rock (in case of constant molecular polymer weight).

Unlike the surfactants the biopolymer viscosity a little higher when salinity increases. But biopolymers become unstable to salinity at great pH values and in the presence of clays.

3.6 Characteristics of formation gas

Gas content (gas factor)

Gas content is a gas volume (under normal conditions) dissolved in a unit of formation fluid volume $G = \frac{V_g}{V_f}$.

Gas content greatly ranges from 0.4 m^3/m^3 to 4500 m^3/m^3 (the Urengoi field - oil fringe).

Gas **solubility** is a maximum gas amount which may be dissolved in a unit of formation oil volume at the given pressure and temperature. Gas content is either equal to solubility or less than it.

Gas factor is a gas amount in m^3 by m^3 of produced degassed oil. Gas content of many formation waters changes from 1 to 4 m^3/m^3 [32] but only in case when methane or nitrogen prevail in gas composition. With CO_2 increase gas content grows several times [14].

3.7 Characteristics of formation substances

Content of nitrogen compounds

Nitrogen compounds are not so widely spread as sulphureous ones and average less than 0.1 % by mass in the chemical oil composition. They are found in complicated aromatic cycles (porphyrin, pyridin, chynolin). Porphyrins, in particular, are rich in nickel and vanadium.

Paraffin content

Paraffins are saturated hydrocarbons of alkane row C_nH_{2n+2}, where $n>16$. Paraffins contained in oil is a mixture of hard hydrocarbons of two groups: paraffins $C_{17}H_{36}$ and cereffins $C_{36}H_{74}$.

Oil classification by the paraffin content in fraction units [19]
- low - paraffinous - 0.0-0.015 by mass;
- paraffinous - 0.015- 0.06;
- high - paraffinous - >0.06.

Paraffins do not dissolve in water. Density of paraffins ranges within 907÷915 g/m^3.

The number of oil deposits with mass paraffin content is over 0.1 fraction units and the problems of crystallization in some of them are unlikely to be great. Oils are mainly found with paraffin content from 0.045 to 0.08 fraction units [19]. In the Uzen field the paraffin content exceeds 0.25. Paraffins may precipitate in the formation if the temperature of its crystallization is close to the formation temperature.

CO_2 injection method is used in field development of paraffinous oils as paraffin content doesn't considerably influence the mechanism of displacement by CO_2 [17].

In case of high-paraffinous oils the share of surfactants in fringe solutions must decrease, and the share of asphaltenes must increase. In low-paraffinous oils the share of surfactants must increase [19]. In case of high-paraffinous oils the concentration of surfactant reagent, at which the temperature of oil saturation by paraffin reduces, is usually high while in low-paraffinous and paraffinous oils this concentration is from 0.015 to 0.04 %.

Asphaltene content

Nonhydrocarbon, high-molecular oil compounds capable of forming over molecular structures are called **asphaltenes**. The content of asphalt - resin substances changes from 0.01 to 0.1 fraction units.

High-molecular hydrocarbons are dissolved in light fractions.

Asphaltenes are found in the state of colloid solutions. Resins and asphaltenes contain polar groups. Due to this property resins and asphaltenes are adsorbed by the surface of sedimentary rocks. In particular, this makes the recovery of residual oil which contains a considerable amount of resins and asphaltenes difficult. Asphaltenes exist as micellar solutions in resin composition. Metals (V, Ni, Fe and others) are located in the centre of micella. Extraction of low-density oil dissolving asphaltenes causes precipitation of the latter and rock plugging.

By its composition the asphaltenes are close to resins but they possess a higher molecular mass. They dissolve in hydrocarbons worse than resins and do not dissolve in paraffin hydrocarbons at all.

The density of asphaltenes is 1000÷1200 kg/m^3. Formation oil viscosity increases with growth of asphalt-resin substances. Along the drop of the formation from the roof to the anticline flank in oil, the content of resins increases, gas content decreases, oil density and viscosity grow. The properties along the formation thickness from roof to bottom change in the same way. On the water-oil contact the content of asphaltenes and resins is very high in oil due to gravitational segregation of low-density movable oil to the roof of the formation, as well as oil oxidation due to sulphates contained in formation water. The presence of asphaltene associates in oil reduces surfactant discharge. The share of surfactants in composition should be increased at higher content of asphaltene-resin substances and lower content of paraffins [19].

The content of asphalt-resin substances has a considerable influence on the mechanism of oil displacement by CO_2. These substances precipitate on the oil-CO_2 contact and can't be extracted from the formation. Reservoir permeability reduces in this case [17].

Resin content

Non-hydrocarbon, high-molecular, structureless oil compounds are called resins.

Oil classification by resin content is accepted in the following way:
- low-resinousness oil, fraction unit - 0.0-0.18
- resinousness - 0.18-0.35
- high-resinousness - >0.35.

Usually resin mass content changes from 0.0 fraction unit to 0.32 fraction units [19].

Asphaltene stabilization (asphaltene micella) is mainly achieved by a solvat layer which consists of resins. When asphalten content increases, the resin mass for a unit of asphaltene mass decreases.

The higher content of resins in oil increases the asphaltene stability thus resulting in the temperature increase of oil saturation by paraffin to 18-10 °C. The main resin components are: hydrocarbon, hydrogen, oxygen, sulphur and nitrogen. Resin density is close to 1000 kg/m^3. Molecular mass is 1200. They dissolve in liquid hydrocarbons very well. In case of high resinousness oils in the surfactant composition the share of synthetical surfactants should predominate [19].

Resin adsorption independently of the composition of sedimentary rocks decreases when pressure and temperute increase. Asphaltenes and naphthenic acids are capable of suppressing resin absorption practically completely. Adsorption of asphalt-resin substances in oil decreases their composition and simultaneously reduces the formation viscosity while the rock surface is hydrophobised [46].

Sulphur content

Sulphur is present in oil as free sulphur and sulfuric hydrogen, as well as in the composition of sulfides, disulfides, sulfuric components, etc.

By sulphur content oils are classified in fraction units as follows:

- low-sulphuous - 0.00-0.05;
- sulphurous - 0.005-0.02
- high-sulphurous - >0.02.

Paraffin saturation point

The temperature at which formation oil is saturated with paraffin and at which paraffin and oil crystallization begins is called paraffin saturation point.

Paraffin saturation point for most oil field ranges from 8 to 65 °C [19].

According to classification proposed by G.F. Trebin formation oil is subdivided into the following groups by proximity of paraffin saturation point and initial formation temperature:

- **group 1** - saturated or close to paraffin saturation when saturation temperature of formation oil is equal or close to the initial formation t ($t_f \approx t_{sat}$);
- **group 2** - undersaturated with paraffin at the paraffin saturation point lower than the formation one by 10 °C ($0 < t_f - t_{sat} \leq 10°$)
- **group 3** - with considerable paraffin undersaturation or paraffinless ($10° < t_f - t_{sat} \leq 20°$).

The laboratory analysis of many deposits shows that in over 50 % of oil fields the complications at the period of development may not arise at all or they arise only under unfavorable circumstances. Right after waterflooding in about 14 % of oil deposits one should expect some problems due to crystallization, while in 15 % of deposits they arise soon after waterflooding and, finally, in 17 % of oil deposits they arise at the stage of additional washing off. Paraffin saturation point drops with higher asphaltene content. Saturation temperature doesn't greatly depend on their content. If mass content of asphaltenes is over 4-5 %, and paraffins - over 20-25 %, the paraffin saturation point doesn't greatly depend on their content. A negative influence of asphaltenes increases if paraffin molecular weight grows, and it decreases if resin content grows. When the increase of resin content is 12-16 %, the paraffin saturation point doesn't practically change, while the increase of resin content to 32 % results in an increase of paraffin saturation point to 18-20 °C [19].

3.8. Petrographo-mineralogical rock composition

Petrographo-mineralogical rock composition has a considerable effect on adsorption of polymers, surfactants and other substances. Calcium, dolomite and clay materials cause high adsorption. Silicates with partially negative changes have the lowest adsorption activity.

Cement content

Cement content in oil and gas reservoirs ranges from 0 to 0.50 fraction unites.

Steam injection method results in destruction of rock skeleton and a considerable growth of sand withdrawal in the wells. So this method is used in packets of high cementation [47].

When sulphuric acid reacts with rock cement, the latter becomes destroyed, so the sulphuric acid fringe is injected at higher injection rate [30].

Content of swelling (monomorrilonite) clays

High content of swelling clays sometimes requires application of hot water injection method instead of steam fringe injection due to swelling of clays in contact with pushing cold water [10, 52]. Residual water saturation increases at higher clay content. Clay materials may preserve adsorbed water during all the processes of steam and hot water injection because the temperature values characteristic of these processes are not enough for a complete water desorption.

The alkali losses increase if the content of swelling clays is higher [16, 18]. The highest rate of swelling the clays is observed during the first minutes when they are in contact with the alkaline solution, then it slows down. The higher alkali concentration in the solution is, the lower the coefficient of swelling is. Clay content over 15-20 % had a considerable influence on oil displacement when alkali solutions were injected. In this case the losses of alkali increased due to the greater amount of alkali reacting with clay.

Adsorption of heavy fractions of formation oil on the surface of clay minerals results in formation of a protective layer which prevents water adsorption and, hence, clay swelling.

Surfactant adsorption increases if clay content is higher [46].

Water polymer solution injected into the formations with clay content over 5-10 % in the presence of clay may result in reciprocal coagulation of two different colloid systems. In addition, due to a considerable area of rock surface clay minerals cause great polymer losses. Biopolymers (csantan, glucan) as well as PAA are easily and strongly adsorbed in the presence of clay minerals. Moreover, adsorption becomes greater if salinity increases.

Carbonate content

When CO_2 is injected, carbonates may dissolve in water containing CO_2. A higher injection pressure increases carbonate solubility, especially in the bottom-hole zone [17].

Table 3.1. Criteria of RM applicability

Group of parameters	Name of parameters	Measuring units	Ranges of changing parameters in oil reservoirs
1	2	3	4
1. Rock	1.Rock type	-	terr., carb.
	2. Reservoir type	-	por., fract., mixed
	3. Permeability	mcm^2	0.0001-20.0
	4. Porosity	unit fraction	0.001-0.50
	5. Oil saturation	unit fraction	0.0-1.0
	6. Bound water	unit fraction	0.01-0.70
	7. Average contact angle	degree	0-180
2. Formation	1. Thickness	m	0.0-100.0
	2. Thickness of water saturation zone	m	0.5-30.0
	3. Thickness of overlying rocks	m	3.0-100.0
	4. Pressure	MPa	1.0-60.0
	5. Temperature	°C	0.0-200.0
	6. Angle of dip	degree	0.-90
	7. Occurence depth	m	0.0-6000.0
3. Formation oil	1. Density	kg/m^3	575-1100
	2. Viscosity	mPa·s	0.01-1500
	3. Acid number	mg/g	0.01-10.0
4. Formation water	1. Mineralization	g/l	0.0-210.0
	2. ph	unit fraction	2.0-14.0
	3. Hardness	g/l	0.0-100.0
5. Formation gas	1. Nitrogen compounds content	unit fraction	0.00-0.02
	2. Availability free gas	unit fraction	favourable
6. Formation substances	Content of:		
	1. Paraffin	unit fraction	0.00-0.30
	2. Asphaltenes	unit fraction	0.00-0.15
	3. Resins	unit fraction	0.00-0.40
	4. Sulphuc	unit fraction	0.00-0.08
	5. Temperature of paraffin saturation	°C	8-65
7. Petrographo-mineralogical composition	Content of:		
	1. Cement	unit fraction	0.00-0.30
	2. Clays	unit fraction	0.00-0.25
	3. Carbonate content	unit fraction	0.00-1.0

Table 3.1. (continued)

Name of parameters	Hydrodynamic methods	Thermal methods			Physico-chemical methods
	Flooding	Hot water injection	Steam injection	In-situ combustion	Surfactante injection
2	5	6	7	8	9
1.1.	terr., carb.	terr., carb.	terr., carb.	terr.	terr., carb
2.	porous	porous, fractues	porous	porous	porous
3.	0.1-5.0	0.1-3.0	0.01-3.0	0.1-5.0	0.1-2.0
4.	0.1-0.5	0.1-0.3	0.04-0.3	0.18-0.4	0.1-0.35
5.	0.7-1.0	0.7-1.0	0.4-1.0	0.4-1.0	0.7-1.0
6.	trivial	0.0-0.3	0.0-0.3	0.0-0.3	0.00-0.15
7.	0-90	trivial	trivial	0-180	0-180
2.1.	3.0-100	10-25	6-25	3-20	7-15
2.	trivial	trivial	0.0-3.0	0.0-3.0	trivial
3.	>3	>3	3.0-100	3.0-100	>3
4.	trivial	1.0-40	1.0-15	trivial	trivial
5.	20-100	0.0-50	0.0-50	trivial	10-50
6.	0.0-5	0.0-5	0.0-5	0.0-3.0	0.0-5.0
7.	trivial	30-2000	30-1000	150-2000	30-1500
3.1.	650-1000	850-1000	800-1100	825-1100	800-950
2.	0.01-25	15.0-1000	50-8000	1.0-1500	0.01-60
3.	trivial	trivial	trivial	trivial	0.01-10
4.1	trivial	trivial	trivial	trivial	0-25
2.	trivial	trivial	trivial	trivial	6-10
3.	trivial	trivial	trivial	trivial	0.0-5
5.1.	trivial	trivial	trivial	trivial	trivial
2.	trivial	trivial	unfavourable	trivial	unfavourable
6.1.	0.00-0.055	0.0-0.3	0.0-0.3	0.0-0.3	0.0-0.02
2.	trivial	0.0-0.15	0.0-0.15	0.0-0.15	0.0-0.1
3.	trivial	0.0-0.4	0.0-0.4	0.0-0.4	0.15-0.4
4.	0.0-0.02	0.0-0.08	0.0-0.08	0.0-0.02	trivial
5.	Tr>Tp	trivial	trivial	trivial	8-65
7.1.		0.1-0.3	0.1-0.3	0.1-0.3	trivial
2	0.0-0.05	0.0-0.25	0.0-0.05	0.0-0.1	0.0-0.1
3.	trivial	trivial	0.0-0.05	-	-

Table 3.1. (continued)

Named of parameters	Physico-chemical methods				
	Polymer injection	Alcali injection	Sulfuric acid injection	Micellar-polymer flooding	Carbonized flooding
2	10	11	12	13	14
1.1	ter., carb.	ter., carb.	carb.	ter.	ter.
2.	porous	porous	porous	porous	porous
3.	0.1-2.0	>0.1	0.5-	0.1-2.0	0.1-5.0
4	0.1-0.35	-	-	0.1-0.35	0.1-0.5
5.	0.5-1.0	0.6-1.0	0.7-1.0	0.25-1.0	0.4-1.0
6.	-	-	-	-	-
7.	-	0-180	-	0-180	-
2.1.	trivial	-	-	-	2-100
2.	trivial	-	-	-	-
3.	>3	>3	>3	>3	>3
4.	5-60	-	-	10-60	10-60
5.	0.0-5.0	-	-	-	-
6.	trivial	-	-	-	-
7.	trivial	-	-	-	30-5000
3.1.	820-950	-	-	850-940	-
2.	0.1-100	0.01-40	0.01-30	0.01-20	-
3.	-	0.01-10	-	-	-
4.1	0.0-20	0.0-50	0.0-150	0.0-50	-
2.	4-10	-	-	4-10	-
3.	0.0-5	0.0-0.025	0.0-5	0.00-0.025	-
5.1.	trivial	-	-	-	-
2.	unfavourable	-	-	inadmissible	-
6.1	-	-	-	-	-
2.	-	-	0.0-0.1	-	0.0-0.05
3.	-	-	0.0-0.2	-	0.0-0.1
4.	-	-	-	-	-
5.	-	-	-	-	-
7.1.	trivial	-	0.1-0.3	-	-
2.	0.0-0.1	0.0-0.1	-	0.0-0.05	-
3.	-	-	0.01-0.25	-	-

Table 3.1. (continued)

Name of parameters	Gas		methods		
	Nitrogen	injection	CO2	injection	Hydrocarbon solvents injection
	Mixed	Non-mixed	Mixed	Non-mixed	
2	15	16	17	18	19
1.1.	terr.	terr.	terr.	terr., carb.	terr.
2.	porous	porous	porous	porous	porous
3.	0.0001-3	0.005-3	0.0001-3	0.005-3	0.005-3
4.	0.04-0.35	0.04-0.35	0.04-0.35	0.04-0.35	0.04-0.35
5.	0.25-1	0.5-1	0.25-1	0.5-1	0.4-1
6.	-	-	-	-	0.0-0.3
7.	trivial	trivial	trivial	trivial	trivial
2.1.	6-30	6-30	6-30	6-30	6-40
2.	0-3	0-3	0-3	0-3	0-3
3.	3-100	3-100	3-100	3-100	3-100
4.	35-55	5-55	8-55	5-55	5-55
5.	20-200	20-200	20-200	20-200	20-200
6.	0-90	0-5	0-90	0.0-5	0.0-5
7.	2200-6000	360-600	900-6000	700-6000	400-6000
3.1.	650-880	650-920	650-880	650-1000	650-880
2.	0.01-25	0.4-10	0.01-12	10-1000	0.1-50
3	trivial	trivial	trivial	trivial	trivial
4.1.	trivial	trivial	trivial	trivial	trivial
2.	trivial	trivial	trivial	trivial	trivial
3.	trivial	trivial	trivial	trivial	trivial
5.1.	0.00-0.02	0.00-0.02	0.00-0.02	0.00-0.02	0.00-0.02
2.	inadmissible	inadmissible	inadmissible	inadmissible	inadmissible
6.1.	-	-	0.0-0.3	0.0-0.3	-
2.	-	-	0.0-0.1	0.0-0.1	-
3.	-	-	0.0-0.15	0.0-0.15	-
4	-	-	trivial	trivial	-
5.	-	-	-	-	-
7.1.	trivial	trivial	trivial	trivial	trivial
2.	0.0-0.05	0.0-0.05	0.0-0.05	0.0-0.05	0.0-0.05
3	-	-	-	-	-

Table 3.1. (continued)

Name of parameters	Gas methods		Microbiological		
	injection of enriched gas	gas injection under high pressure	Bio-surfactant injection	Biopolymer injection	
				Ksantan	Scleroglutan
2	20	21	22	23	24
1.1	terr.	terr.	terr., carb.	terr.	terr.
2.	porous	porous	porous	porous, fract.	porous
3.	0.005-3	0.0001-3	0.1-5	0.05-5	0.1-5
4	0.04-0.35	0.04-0.35	0.25-0.4	0.25-0.4	0.25-0.4
5.	0.5-1	0.4-1	0.7-1	0.7-1	0.7-1
6.	0.0-0.2	0.0-0.2	-	-	trivial
7.	trivial	trivial	-	-	trivial
2.1.	6-25	6-15	-	-	3-20
2.	0-3	0-3	-	-	0.0-0.05
3.	3-100	3-100	>3	>3	trivial
4.	20-55	25-55	-	-	1-20
5.	20-200	20-200	10-90	10-150	0-150
6.	0.0-5	0.0-90	trivial	trivial	0-5
7.	400-7000	800-7000	30-1500	30-1500	30-1500
3.1.	650-925	650-880	650-859	650-850	650-850
2.	0.1-20	0.4-10	0.4-60	0.4-25	0.4-25
3.	trivial	trivial	-	-	trivial
4.1	trivial	trivial	0-300	0-150	0-350
2.	trivial	trivial	6-7.5	6-7.5	6-7.5
3.	trivial	trivial	0-10	0-10	0-150
5.1.	0.0-0.02	0.0-0.02	-	-	trivial
2.	inadmissible	inadmissible	admissible	admissible	inadmissible
6.1	-	-	-	-	0.0-0.3
2.	-	-	-	-	0.0-0.15
3.	-	-	-	-	0.0-0.4
4.	-	-	-	-	trivial
5.	-	-	-	-	trivial
7.1.	trivial	trivial	-	-	-
2.	0.0-0.05	0.0-0.05	-	-	trivial
3.	-	-	-	-	-

Table 3.1. (continued)

Named of parameters	Bio-polymer injection (polysacharide S-130)	Activization of natural microflora	Melassie flooding
2	25	26	27
1.1	terr.	terr.	terr., carb.
2.	porous	porous	porous, fract.
3.	0.1-5	0.1-5	0.1-5
4	0.25-0.4	0.25-0.4	0.25-0.4
5.	0.7-1	0.7-1	0.5-1
6.	trivial	-	trivial
7.	trivial	-	trivial
2.1.	3-20	-	3-100
2.	0.0-0.05	-	0.0-0.05
3.	trivial	>3	trivial
4.	1-20	-	0-15
5.	0-150	10-40	20-60
6.	0-5	trivial	0-10
7.	30-1500	30-2000	0-1500
3.1.	650-850	trivial	650-900
2.	0.4-25	0.01-20	0.1-60
3.	trivial	-	trivial
4.1	0-350	0.0-20	0-100
2.	6-7.5	6.5-7.5	6-8
3.	0-300	0-5	0-20
5.1.	trivial	-	trivial
2.	inadmissible	admissible	inadmissible
6.1	0.0-0.3	-	0.0-0.3
2.	0.0-0.15	-	0.0-0.15
3.	0.0-0.4	-	0.0-0.40
4.	trivial	-	trivial
5.	trivial	-	trivial
7.1.	-	-	trivial
2.	trivial	-	trivial
3.	-	0.0-0.05	0-1

"-" - data not available

4. Efficiency of recovery methods

Two parameters are introduced to determine the efficiency of recovery methods application:

- technological efficiency:
- economic efficiency.

Technological efficiency of a recovery method means mass or volume of additionally extracted oil in relation to mass or volume of injected working agent.

Economic efficiency means the obtained profits (expressed in money) as a result of introducing the given recovery method.

Tables 4.1, 4.2 and 4.3 show the main technico-economic indexes of RM efficiency [52, 55, 56, 58, 67, 68, 77]. Economic and technological efficiencies enable to classify the results of RM introduction into successful and unsuccessful projects. Given below is the table of technological efficiency of realising development projects using some RMS.

The table shows that there exists an intermediate area, the so-called uncertainty area, between successful and unsuccessful projects. These are the projects the successfulness of which is hard or early to judge about or to evaluate.

One of the main tasks in oil field development design using RMS is determination of well spacing density. Nowadays most of the above methods are being tested at the stage of pilot exploitation. Only steam and CO_2 injection methods are widely used in oil field development. So the recommended well spacing density should be mentioned with great certainty only for these two recovery methods, while for the rest methods the certainty of the recommended well spacing is much lower. Table 4.4 shows the recommended well spacing densities obtained for these methods [11].

For the last decade the expenses for realisation of the main recovery methods reduced. It was greatly due to cheaper working agents, as well as reduced exploitation charges. Application of recovery methods at the early development stages results in considerable decrease of expenses

The importance of performing calculating experiments to determine optimum characteristics of the working agent fringe should be noted, as the costs depend on volume and concentration of a working agent.

Table 4.1. Technological indexes of recovery methods efficiency

№	recovery method	Technological efficiency, t of extra produced oil for 1 t of reagent	oil recovery increment (%) (in successful projects)	ultimate recovery, %	value range of well spacing density	production rate of a producing well t/daily
1	flooding	-	10-30	45-50	-	-
2	steam	-	15-35	-	0.1-0.8	2.5-6.5
3	hot water	-	5-15	-	0.2-14	0.5-5
4	in-situ combustion	-	12-30	-	-	-
5	surfactant	8.77-17.5	2-10	-	0.6-12	1-6
6	polymer	79-255	2-15	-	-	-
7	alkali	5.85-12.8	2-5	-	-	-
8	sulphuric acid	-	5-11	-	0.1-24	0.1-6
9	micellar- polymer flooding	100-600	8-20	55-60	4-16	0.5-20
10	CO_2	0.2-2.3	8-15	55-60	2.5-12	-
11	nitrogen	-	5-10	-	-	-
12	hydrocarbon gases	-	5-10	-	-	-
13	hydrocarbon solvent	2.92-3.33	23-42	55-60	-	-
14	carbonised flooding	-	5-12	-	-	-
15	solution gas drive	-	-	5-20	-	-
16	gas drive	-	-	10-40	-	-
17	compressive water drive	-	-	50-80	-	-
18	gravitational	-	-	10-30	-	-
19	compressive	-	-	10-30	-	-

Table 4.2. Economic efficiency of RMs application

Method	Cost of 1 m of extra produced oil USD	Specific capital expenditures, thousand USD / m^3/ daily	Cost of 1 t reagent, injection roubles (1990)	Cost of 1 t of extra produced oil, roubles	Price of 1 t of produced oil USD
in-situ combustion	63-157	50-157	-	-	-
steam	63-119	50-157	-	-	46.9
CO_2 injection	63-189	63-157	510	7.3	51.3
polymers	63-157	63-189	-	-	50.0
surfactants	126-314	94-189	200	2.0	112.5
bio-surfactants, biopolymers	-	-	-	-	19-20

Table 4.3. Technological efficiency of RM application

№	Recovery method	Unit of measuring	Average specific technological efficiency	Index of efficiency (successfulness)	Index of inefficiency (unsuccessfulness)
1	steam injection	t/t	0.3	>0.3	<0.15
2	in-situ combustion	t/m^3	-	-	-
3	polymer injection	t/t	260	>150	<75
4	surfactant injection	t/t	12-200	>50	<15
5	alkali injection	t/t	12	>30	<10
6	acid displacement	t/t	-	>10	<3
7	hydrocarbon gases injection	t/ thousand m^3	0.5	>1	<0.4
8	CO_2 injection	t/ thousand m^3	1.5	>0.8-2	<0.2
9	micellar - polymer flooding	t/t	100-600	>150	<50

Table 4.4. Recommended WPD for some RMs

№	Recovery method	Well pattern density, acre/well
1	flooding	39.5-59.3
2	hot water injection	49.4-61.7
3	steam injection	6.2-19.8
4	in-situ combustion	12.3-49.4
5	surfactant injection	12.3-49.4
6	polymer injection	18.5-32.1
7	alkali injection	12.3-24.7
8	miccellar-polymer injection	1.2-18.5
9	acid injection	12.3-24.7
10	carbonised flooding	12.3-49.4
11	nitrogen injection	24.7-49.4
12	CO_2 injection	24.7-123.5
13	hydrocarbon gas injection	24.7-49.4

Table 4.5. Resource requirements for the main recovery methods by the year of 2000

№	Method	Agent / oil	Produced oil, million t	Demand for agent
1	flooding (water)	6-8 m^3/t	500	3-4 billion m^3
2	steam	3-4 t/t	14	45-50 billion t
3	air	1000-3000 m^3/t	2	2-6 billion m^3
4	gas injection (natural gas, CO_2, N_2)	1500-2500 m^3/t	10	15-25 billion m^3
5	polymer flooding	0.005-0.01 t/t	6	30-60 thousand t
6	surfactant, alkali	0.05-0.1 t/t	4.5	250-450 thousand t

Application of recovery methods together with natural drives of oil field development results in (by preliminary evaluations) considerable *shortening of development period and reduction of specific expenses* for the recovery of 1 t of oil up to 30 % [77].

5. Choice of a recovery method

To analyse complicated systems in which human knowledge and experience play an important role and where it's difficult to use traditional quantitative methods, we propose to use fuzzy set logic [22, 23, 24, 26, 28, 42].

Formation systems together with the fluids and gases saturating them are a classical example of a complicated system where physical uncertainty of an object is connected both with a stochastic uncertainty (accidental situation) and with a principally impossible exact determination of certain physical parameters of environment performed with the help of physical devices (fuzzy situation). All this enables to refer formation objects to the class of fuzzy environments and the solution of choosing RMs to taking a decision in a fuzzy environment. Notions and relations describing such classes are called fuzzy, and the theory of fuzzy sets [27] serves as a means of formalising fuzzy notions and relations. The theory of fuzzy set (FST) may quantitatively evaluate such category notions as «very good» or «very bad» and this is very important in the solutions like the choice of a recovery method when formation (field) parameters differ anyhow from the applicability criteria. The task of choosing oil recovery methods is complicated by the fact that some methods have a common zone of applicability by a number of parameters and hence there arises a problem of choosing the most efficient recovery method out of the considered totality.

The fuzzy set theory enables to give a definite differentiation of each point (elementary volume) of oil formation by geologo-physical parameters to evaluate its degree of belonging to fuzzy set.
To construct the algorithm of choice solution and further convenient interpretation we'll introduce the main notions of fuzzy set theory [24, 26, 42].

Fuzzy set A by set U=(u) is called a totality of pairs

$A=\{<\mu_A(u), u>\}$, (5 1)
where μ_A- a belonging reflecting set u for a unit period [0.1]·

$$\mu_A : u \rightarrow [0.1] \qquad (5.2)$$

1. Construction of a geological model
2. Making up matrixes of applicability criteria
3. Construction of applicability functions
4. Definition of applicability coefficients
5. Definition of sweep efficiency with different applicability coefficients by a formation
6. By a field
7. Choice of recovery methods (combined method).

The value of belonging function $\mu_A(u)$ for element $u \in U$ will be called a degree of belonging element U to A set or simply a belonging degree
At last the carrier of fuzzy set A is called such set S that

$$S_A = (u \in U: \mu_A(u) > 0) \qquad (5.3)$$

In case if a basic vector variable ($x = (u, v, w, \ldots)$), each component of which is an element of its universal set ($u \in U$, $v \in V$, $w \in W$, etc.) a fuzzy set R, formed by a totality of pairs

$$R = \bigcup_{x=(u,v,w,\ldots)\in U\cdot V\cdot W} \mu_R(u,v,w,\ldots)/(u,v,w,\ldots) \qquad (5.4)$$

is called a fuzzy relation. In this case $\mu_R: U\cdot V\cdot W\cdot\ldots[0.1]$ is a belonging function of a fuzzy relation R.
According to the above said, when constructing the model of solving the task of RM choice on the basis of a linquistic approach, at the first stage it's necessary to determine set S_A including all the elements and for which condition (5.3) is made. First of all this procedure includes two operations:

- determining on set U the values of some geologo-physical parameter of a subset (interval, semi-interval) all the elements of which determine the conditions of successful application of some RM by the given parameter;
- constructing the belonging function $\mu_A(u)$.

The first procedure is made by analyzing either available statistical data of the successful application of RM under different geologo-physical conditions, or on the basis of an expert's opinion, or by combination of both ways. The result of such an analysis is applicability criteria of various RMs by each of the considered totality of geologo-physical parameters (see Table 3.2).

Let's begin the description of the second procedure - construction of the belonging function. Keep in mind that to determine the carrier S_A of a fuzzy set A (for example, S^j_{Ai} ≡ «applicability area of j -RM by i - geologo-physical parameter») it's necessary to determine for each element $u_{i,j}$ the set u_i of the i - parameter the values of belonging function (i.e., degree of belonging degree) $\mu^j_{Ai}(u_{ij})$.

There exist a great number of ways of belonging function construction (BF). Let's consider two methods in detail.
The first method is based on an axiom task of BF type and further defining its separate parameters more precisely. Transition point u* is such an element of U set for which ratio $\mu_A(u^*)=0{,}5$; $u^* \in U$ is true. The belonging function was chosen in the following way:

$$\mu_i = \begin{cases} 0, \; x < x_{\min} \\ \left[1+\left[\dfrac{x - x_{\min 1}}{x_1^* - x_{\min 1}}\right]^{n1}\right]^{m1} x_{\min 1} \le x \le x_{\max 1} \\ 1, x_{\max 1} \le x \le x_{\min 2} \\ \left[1+\left[\dfrac{x_{\max 2} - x}{x_{\max 2} - x_2^*}\right]^{n2}\right]^{m2} x_{\min 2} < x \le x_{\max 2} \\ 0, x > x_{\max 2} \end{cases} \qquad (5.5)$$

where x^*_1, x^*_2 - transition points for left and right BF branches (Fig. 5.1); $x_{\min 1}$, $x_{\max 2}$ - values of x variable, their belonging degree being 0 for both branches; $x_{\max 1}$, $x_{\min 2}$ - variable values with the belonging degree equal to 1 for both branches. In case when $x_{\min 2} \to m$, we have BF only with the left branch (Fig. 5.2), if $x_{\max 1}0$, then it is only with the right branch (Fig. 5.3). BF type construction (5.5) is performed elementary: for example, by taking points $x=x_{0,1}$ and $x=x_{\max 1}$ for the left branch we determine coefficients n_1 and m_1, moreover, it's probable that n1<0 and m1<1. Under this condition $\mu_A(x_{\max 1}) = 0$ is made automatically.

1. The second method based on using S - type function (type of Barkli - Leveretta function). In such a way of describing BF, its dependence of dimensionless parameter Y will be the following:

$$\mu_A(Y)=(1+Y)^{-1} \qquad (5.6)$$

Where $Y = [(\dfrac{u_{\max i} - u_i^*}{u_i^* - u_{\min i}})^2 (\dfrac{u - u_{\min i}}{u_{\max i} - u})^2]^{a_i}$

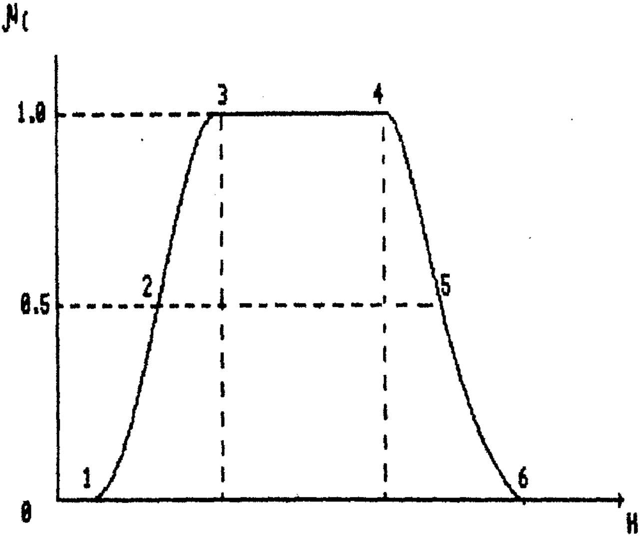

Fig. 5.1.View of belonging function:

$\mu_{(h)}$ – value of applicability function; H- set of parameter values;

1,6 – points corresponding to the formation thickness, their belonging being degree equal to 0;

2,5 – transition points;

3,4 – points corresponding to the values of formation thickness, their belonging degree being equal to 1.

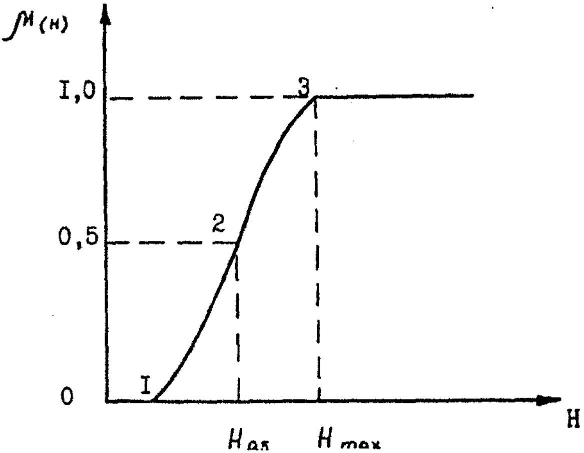

Fig. 5.2. View of belonging function with the left branch

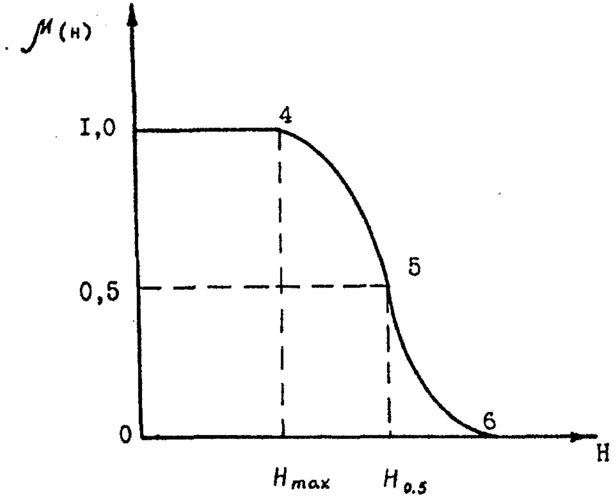

Fig. 5.3.View of belonging function with the right branch.

U_{mini} and U_{maxi} - minimum and maximum values of U variable for the left (i=l) and the right (i=R) BF branches, respectively; U_i^* - transition point in which the corresponding BF point takes its value equal to 0.5.

The procedure of BF construction reduces to giving three values of the considered geologo-physical parameter for each function branch in which BF takes values 0, 0.5 and 1.0.

In conclusion it should be noted that to use one of the above approaches, as well as the others, in BF construction, the interactive method of communication of the DMP (expert) performing BF construction and the personal computer. The AP (application package) «Method» worked out to solve the task of RM choice, provides an independent block of programs enabling the DMP (decision making person) to define more precisely, if desired, any kind of BFs available in the program of data base in the interactive regime.

5.1. Application of fuzzy set theory for a complex evaluation of various RMs applicability combined with geologo-physical parameters and solution of RM choice task

To determine if either RM is applicable under certain geologo-physical conditions, let's introduce the idea of applicability coefficient of j-RM, or simply applicability coefficient C_j being a parameter of complex applicability evaluation of the considered RM combined with geologo-physical properties of formation and saturating its fluids and gases.

There exist several methods to find the applicability coefficient the basis of which are operations determined by fuzzy sets and operations with belonging function.

As the applicability coefficient C_j of j-RM is a parameter of complex evaluation, the set $A^j \cong$ «applicability of j - recovery method» must be formed as a result of crossing of A_i^j sets «applicability of j-RM along the i - geologo-physical parameter».

$$A^j = A_1^j \wedge A_2^j \dots \wedge A_n^j = \underset{i \in [1,n]}{\wedge} A_i^j \qquad (5.7)$$

Taking into account this feature of the considered task, the construction of the BF $\mu_A{}^j$ of fuzzy set A^j may be given as follows:

$$\mu_A^j = \mu_{A_1}^j \wedge \mu_{A_2}^j \wedge \ldots \wedge \mu_{A_n}^j = \min_{i \in [1,n]} \mu_{A_i}^j \qquad (5.8)$$

Generally speaking, due to the fact that during transition from one elemantary layer volume another its geologo-physical properties change, the values of belonging functions (that is degree of belonging)of the corresponding sets A^j will change as well. Thus the values of BF μ_A^j; i.e. the applicability coefficients will change when passing from one formation point to another, i.e. they'll became some function of coordinates of these formation points, $C_j = C_j(X,Y,Z)$. It's quite evident that using the rules (5.8) the calculation of applicability coefficient in each formation point may be done by ratio:

$$C_j(X,Y,Z) = \min_{i \in [1,n]} C_{ji}(X,Y,Z); \qquad (5.9)$$

where $C_{ji}(X,Y,Z)$ is a degree of belonging, $C_{ji}(X,Y,Z) = \mu_{A^j_i}(X,Y,Z)$.
We may offer quite a different method of calculating applicability coefficient C_j, namely:

$$C_j(x,y,z) = \sum_{i=1}^{n} \lambda_{ji} \cdot C_{ji}(x,y,z) \qquad (5.10)$$

where λ_{ji} - a weight coefficient determining the importance of i-parameter in a complex evaluation of applicability of j-RM under certain geologo-physical conditions and satisfying the condition:

$$\sum_{i=1}^{n} \lambda_{ji} = 1 \qquad (5.11)$$

The importance of each geologo-physical parameter may be determined by a statistical analysis of the data on applying RMs under different conditions/ In case this information isn't available use the method of expert evaluations.
At last, the third method of determining applicability coefficient is based on calculating the average geometric:

$$C_j(x,y,z) = \Big(\prod_{i \in [1,n]} C_{ji}(x,y,z)\Big)^{1/n} \qquad (5.12)$$

and it anyhow reminds the first method.
Each of the considered here methods is likely to have certain advantages and disadvantages. Thus when using the first and third ways, the unapplicability of the method along all the totality of parameters automatically follows from the fact of RM nonapplicability by a certain parameters (see formulas 5.9). On the other hand the second methods unlike the first and the third ones enable take into account the importance of each geologo-physical parameters when determining the applicability RM factor thus improving the general evaluation. The best approach to obtaining a qualitative evaluation of applicability RM is likely to be a

combination of the second approach with the first and the third ones. In combination of the first and the second approaches the second evaluation will always be not worse than the first one as

$$C_j^{*(2)} = \sum_{i=1}^{n} \lambda_{ji} \cdot C^*_{ji} \geq \sum_{i=1}^{n} \lambda_{ji\min}$$

$$i \in [1, n] \qquad (5.13)$$

$$C^*_{ji} = \min C^*_{ji} = C_j^{*(2)}$$

$$i \in [1, n]$$

If evaluations in this case greatly differ, it means that by some very insignificant (not very important) parameter the applicability degree of the given RM is small and requires some modification of the method. The values of the applicability coefficient change from 0 to 1. The change range may be divided into subintervals with the following characteristics (Table 5.1).

Table 5.1. Classification of RMs applicability degree

Subintervals of values Cj	Evaluation of RM applicability degree
0.8-1.0	ideal level
0.5-0.8	well applied
0.2-0.5	badly applied
0.0-0.2	inadmissible level

As mentioned above, due to netereoginity of producing formations the applicability coefficient of the given RM will have different values in different points of the formation, i.e. it will be some function of the coordinates of formation points. This enables to compile maps of applicability of various recovery methods with the help of the following algorithm:

- discretization of the bed trend area, i.e. its covering by the given rule of main points system (knots);
- determining in each knot the values of all geologo-physical parameters necessary for the further analysis and compiling the distribution maps of these parameters within the oil pool outline;
- calculation of the applicability coefficient of the given RM in each of the main points and compiling the map of the given RM applicability under certain geologo-physical conditions.

As an example, Fig.5.4. shows the map of distribution within the oil pool outline of zones with different values of some RM applicability coefficient.

It's evident that the above program supply will help to get the similar information concerning all recovery methods thus enabling to solve the

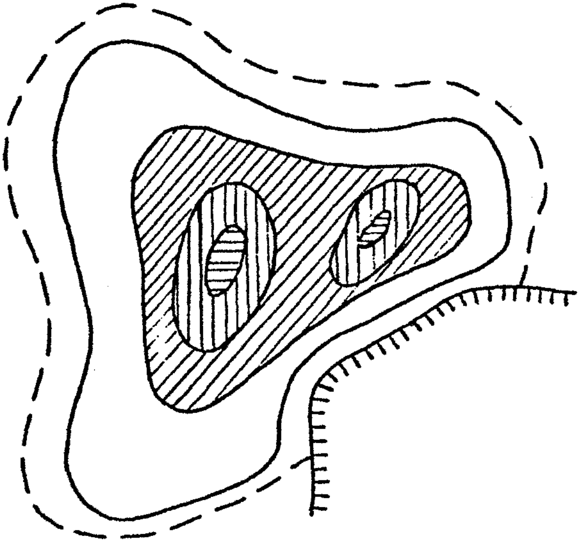

Fig.5.4. Map of distribution within the oil pool outline of zones with different values of some RM applicability coefficient

task of choosing the proper RM (group of methods). To simplify the solution of this task it's necessary to construct distribution histograms of RM applicability coefficient by formation area (Fig. 5.5.)and reserves (Fig. 5.6.). This operation is followed by choosing the RMs, which are most perspective from the point of the future project, solving the following equation:

$$RM: (C_j, G_j\,(C_j))\overline{\;\; j\in[1},n] \qquad 'V_{max}', \qquad (5.14)$$

where C_j - an integral coefficient of j-RM applicability by reserves; G_j - $G_j(C_j)$; $G_j\,(C_j)$ - reserves which may be involved into the development using j - RM with the applicability coefficient not less than C_j.

According to (5.14) the attention of a designer or a person making solution (DMP - decision making person) is concentrated on those RMs which provide the greatest amount of reserves $G_j(C_j)$ covered by either RM at the largest value of an integral applicability coefficient C_j.

In solving the task of RM choice one may use much greater amount of criteria taking into account the risk of using the given RM, the experience of the personnel the quality of oil produced by this RM, etc.

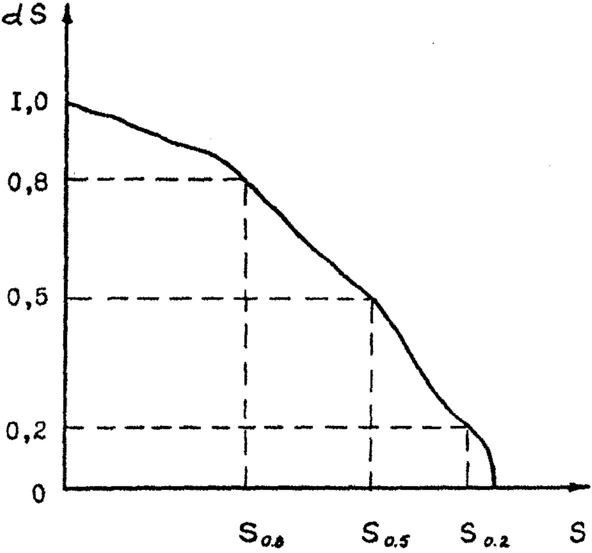

Fig. 5.5. Distribution histogram of RM applicability coefficient by formation area

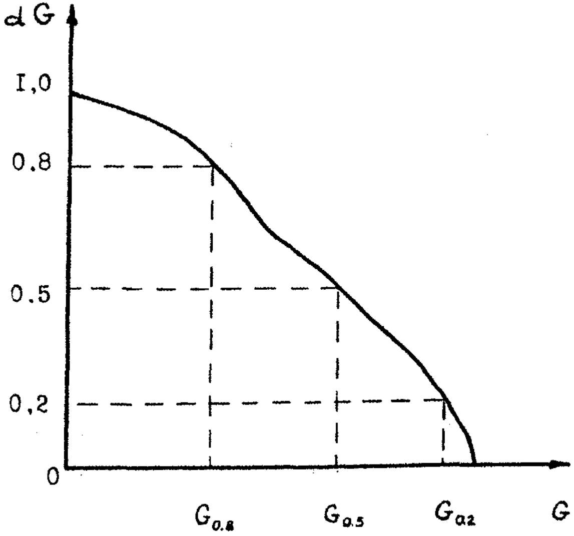

Fig. 5.6. Distribution histogram of RM applicability coefficient by reserves

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Appendix No. 1.

List of Abbreviations

FB - formentation bacteria; Bio-SFs - microbiological surfactants;

WB - wet buring;

ISC-In-situ combustion;

OWC - oil-water contact;

VES - viscous-elastic system;

HDRM - hydrodynamic recovery methods;

LA - log analysis;

GRM - gas recovery methods;

MFCC - micellar formation critical concentration;

CSC - caustic soda concentration;

VIP - very important person;

RM - recovery method;

MBRM - microbiologic recovery method;

IBSTC - interbranch scientific and technological complex;

MFB - methane forming bacteria;

EORM - enhanced oil recovery method;

EOR - enhanced oil recovery;

BHZT - bottom-hole zone treatment;

PAA - polyacrylamide;

SF - surfactants;

MPC - maximum permissible concentration;

BHFZ - bottom-hole formation zone;

BHZ - bottom-hole zone;

AP - application package;

RPM - reservoir pressure maintenance;

WPD - well pattern density;

STS - steam thermal stimulation;

OFD - oil-field development;

SRB - sulfate - reconcentration bacteria;

EWB - extra wet burning;

DSC - dry in-situ combustion;

WSS - well spacing system;

TRM - thermal recovery methods;

FST - fuzzy set theory;

HCOB - hydrocarbon oxidizing bacteria;

FVP - filtration - volumetric properties;

RRF - residual resistance factor;

BF - belonging function;

RF - resistance factor;

PChRM - physico-chemical recovery methods;

LHCWF - light hydrocarbon wide fraction;

PF - production facility.

Appendix No. 2.

Nomenclature

d_p - diameter of polymer molecules;

d_{pore} - pore diameter;

F - viscous force;

Kd_p/d_{pore} - ratio of molecule and pore diameters;

K_m - vertical sweep efficiency;

K_{disp} - displacement efficiency;

$K_{o,w}$ - effective (relative) oil and water permeability;

K_{sw} - areal sweep efficiency;

m - relationship of water and oil mobilities;

pH - hydrocarbon value;

$S_{b.w.}$ - bound water saturation;

S_o - oil saturation;

t_{sat} - oil saturation temperature;

t_{form} - initial formation temperature;

V_g - gas volume;

V_o - oil volume;

$V_{f.f.}$ - formation fluid volume;

V_{pore} - pore volume;

$\gamma(-\partial_w/\partial_y)$ - shear (velocity) gradient;

η- oil recovery factor;

θ - contact angle ;

λ_w - water mobility;

$\lambda_{w\ init}$ - initial water mobility;

$\lambda_{w\ fin}$ - final water mobility;

λ_o - oil mobility;

λ_{Π} - polymer solution mobility;

μ_∞ - lower limited viscosity;

μ_o - upper limited viscosity;

μ_w - formation water viscosity;

μ_o - formation oil viscosity;

ρ_o - formation oil density;

σ - oil-water interfacial stress;

σ_{wr} - water-rock interfacial stress;

σ_{or} - oil-rock interfacial stress;

g - gas content;

τ - tangential stress.

Appendix No. 3.

The list of figures

Fig. 5.4. Map of distribution within the oil pool outline of zones with different values of some RM applicability coefficient

Fig. 5.5. Distribution histogram of RM applicability coefficient by formation area

Fig. 5.6. Distribution histogram of RM applicability coefficient by reserves

Appendix No. 4.

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    - water-oil -

F

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    - temperature -
    - depth -
    - density -

G

- gas -
    - gas cap -
    - natural -
    - gas-oil ratio -
    - gas content -

H

- hydrodynamic -
- hydrogen value ph -

I

- importance of parameter -
- injection -
    - water -
    - hot water -
    - steam -

    -polymer -
    - surfactant -
    - alkali -
    - acid -
    - alcohol -
    - miccelar-polymer -
    - gas -
        - carbon -
        - hydrocarbon -
        - nitrogen -
        - dioxide -
        - enriched -
    - biosurfactant -
    - biopolymer -

M

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- microbiologie -
- microbe -
- mobility -
- model -
    - geological -

O

- oil -
    - heavy -
    - light -

P

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    - geologo-physical -

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- person -
    - decision making -
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- precipitation of
    - sediments -

R

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    - skeleton -

S

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    - gas -

- - formation -
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  - -connect -
  - - cold -
  - - alkali -
- - water influx -
- - weight -
  - - molecular -
  - - polymer -
- - wettability -

Заказ 1026 Тираж 100

Отдел оперативной полиграфии
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