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Analysis of the Performance Indicators of Oil Field Development in Uzbekistan to Evaluate the Hydrodynamic System

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Abstract

Analysis and generalization of materials on hydrodynamic systems in the oil and gas regions of Uzbekistan. Application of mathematical statistical methods in processing geological and technological data. The properties of water-oil emulsions were utilized to evaluate the performance of the hydrodynamic system under elastic pressure conditions. By comparing the fluids extracted from the reservoir through the filtration hydrodynamic system, the actual and calculated values of reservoir pressure variation range from 1.21 to 2.5. For objects with an ellipsoidal hydrodynamic system, these values vary from 3.1 to 4.7.

For the geological-physical and technological conditions of the Northern Urtabulak field, the flow coefficient is equal to 1.91. By intensifying fluid extraction from the reservoir with underlying water, it is possible to double the production capacity.

The obtained results make it possible to assess the efficiency level of the hydrodynamic system, predict reservoir performance modes, select fluid extraction rates, and determine the necessary measures to maintain reservoir pressure. These results are recommended for use in developing oil field operation projects by "O'zLITIneftgaz" JSC during the process of reserves calculation, to justify reservoir operation modes and oil recovery factors. Additionally, they are recommended for use by "IGRNIGM" JSC to substantiate methods of reservoir impact and the rates of fluid extraction.

Keywords: Water and elastic pressure, hydrodynamic system, infiltration, elision.

Introduction

In the Republic of Uzbekistan, oil and gas regions are divided into five distinct zones based on geological structure, oil and gas complexes, types of fields, reservoir types, and natural storage characteristics. Additionally, each field is distinguished by unique geological features, including the activity of its hydrodynamic system.

As mentioned above, the scientific justification of a method that enables the evaluation of the hydrodynamic system's performance in oil fields operating under water and elastic pressure regimes is of critical importance.

Methods for Evaluating the Performance of Hydrodynamic Systems and Modes of Hydrocarbon Reservoir Development

All hydrocarbon reservoirs have either large or small reserves and are influenced by various types of energy that drive the movement of oil and gas towards wells. In this regard, the potential capabilities of the formations depend on the natural energy type of the reservoirs. The significance of the initial reservoir pressure and the dynamics of pressure changes during production play a crucial role in the manifestation of these modes.

Natural water systems are divided into infiltration and elysion types, differing in their spatial arrangement, formation conditions, and initial dimensions. Accordingly, hydrocarbon reservoirs confined by such water systems typically exhibit effective formations at depths corresponding to the initial reservoir pressure values. High hydrostatic pressure is characteristic of Elysion water systems. In such systems, saturated pressure increases under the influence of rising geostatic pressure, which results from precipitation and the formation of sedimentary rocks within collectors and partially in the collector itself (geostatic Elysion systems). Alternatively, it may arise due to geodynamic pressure caused by tectonic disruptions (geodynamic Elysion systems). In an Elysion system, the supply area is formed in the deepest part of the reservoir collector. Consequently, the water entering this area moves toward the boundaries of the reservoir. In infiltration systems, the vertical reservoir pressure gradient of oil and gas accumulations, even considering overpressure, is typically 0.008–0.013 MPa/m. The upper limit is more common for high-altitude gas fields. Occasionally, in the free gas zone corresponding to the infiltration system, the gradient value may exceed the aforementioned range. In the accumulation zones of infiltration water system fields, the high reservoir pressure should not be confused with hydrostatic pressure.

The conformity or nonconformity of hydrostatic pressure in a reservoir (i.e., the formation depth of the reservoir) should be evaluated based on the pressure value in the liquid phase of the reservoir. This evaluation is conducted either directly from the boundaries of the accumulations or, in the absence of pressure measurements, using pressure values measured within the reservoir and brought to the average level of WOC or WGC along horizontal planes. In water layers, the initial reservoir pressure, as well as the vertical gradient, corresponds to the hydrostatic reservoir pressure. Beyond these values, this indicator is referred to as the average hydrostatic pressure at the boundaries of WOC and WGC. Typically, a reservoir is considered to have high hydrostatic pressure if $P_{gq} > 0.013$ and low hydrostatic pressure if $P_{gq} < 0.008$. High hydrostatic pressure is characteristic of Elysion water systems. In such systems, saturated pressure increases under the influence of rising geostatic pressure, which results from precipitation and the formation of sedimentary rocks within collectors and partially in the collector itself (geostatic Elysion systems).

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In an Elysion system, the supply area is formed in the deepest part of the reservoir collector. Consequently, the water entering this area moves toward the boundaries of the reservoir.

Natural water systems are classified into infiltration and elision types, which differ in their mutual arrangement, formation conditions, and initial parameters. Accordingly, hydrocarbon accumulations confined by such water systems generally feature effective layers that exhibit initial formation pressure values corresponding to the depth at which they are located. .[17,18,19].

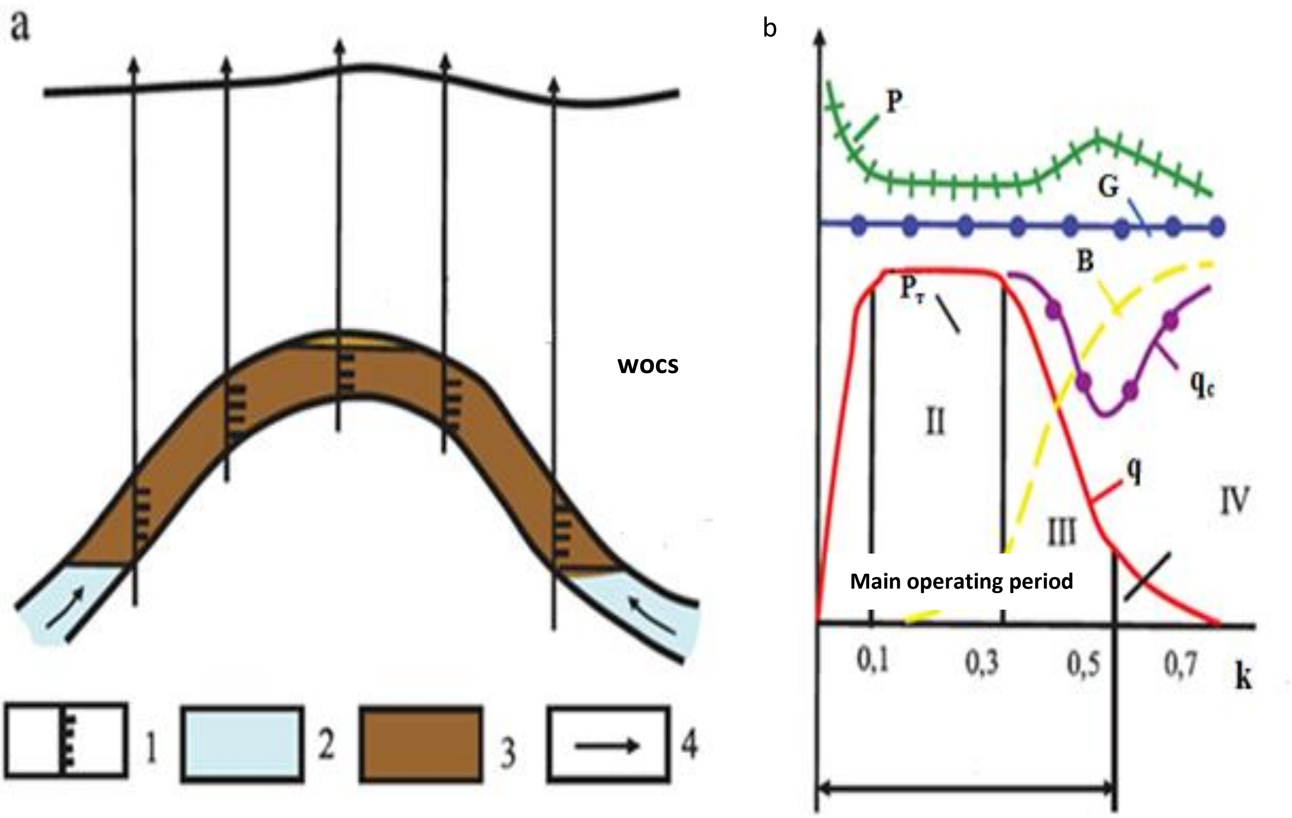

Figure 1. Oil accumulation operating under a natural water pressure regime:
a – changes in the volume of the accumulation during the process;
b – dynamics of the main performance indicators;
1 – opened intervals; 2 – water; 3 – oil; 4 – direction of water and oil flow;
WOCS states: WOCS$_i$ – initial, WOCS$_f$– final;
Pressures: P_r – reservoir pressure, P_s – saturation pressure;
Annual production: q_o – oil, q_l – liquid;
V – water content of the product;
G – gas factor;
k_{orf}– oil recovery factor.

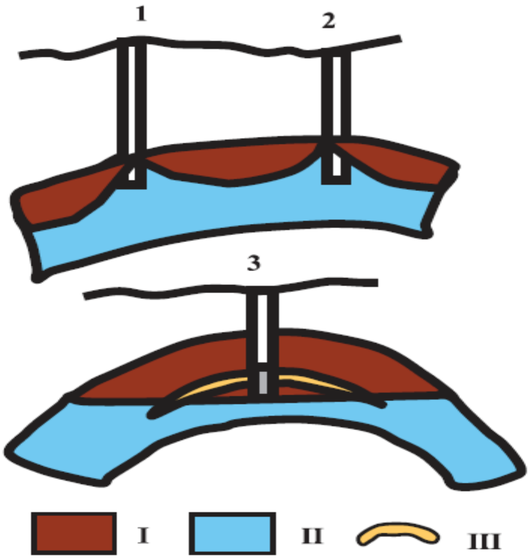

Figure 2. Diagram of the positioning of water coning in oil accumulations with underlying water:
I – oil; **II** – water; **III** – clay layer; **1, 2, 3** – wells.

The hydrodynamic system of all oil fields varies depending on the geological conditions. In oil fields with an infiltration water supply system, water-driven and elastic water-driven regimes are predominantly observed, whereas in fields covered by an elysion water system, weaker regimes such as tension, dissolved gas regimes, and gravity regimes are present.

In water-saturated systems under water and elastic pressure regimes, the highest oil recovery coefficient of 0.6-0.7 is achieved by maintaining reservoir pressure artificially through natural infiltration water supply and water flooding. Calculations show that in oil fields with an infiltration hydrodynamic system, the actual rate of pressure drop in the reservoir compared to the project value ranges from 1.21 to 2.5, whereas in accumulations with an Elysion hydrodynamic system, it ranges from 3.1 to 4.7, i.e., 2-3 times higher than the infiltration pressure.

Based on the comparison of actual and calculated pressure drop rates, the evaluation of the hydrodynamic system's performance is only accepted for elastic pressure regimes. Therefore, incorrect choices in operating regimes can lead to incorrect conclusions, which makes it necessary to evaluate the hydrodynamic system's activity under water and elastic pressure regimes.

Determining the activity of the hydrodynamic system in water and elastic water pressure regimes.

Each reservoir's (deposit's) geological structure has unique features, including the activity of water flow, which significantly affects the process of oil reservoir exploitation. Today, methods for determining the activity of the hydrodynamic system mainly involve comparing the rate of change between the actual and calculated values of reservoir pressure. The theoretical foundation of this approach has been developed for conditions where elastic water effects play a role in displacing oil from the reservoir.

It is well known that, currently, methods such as water injection into depleted reservoirs and several other techniques are being used to exploit the entire area of oil deposits. In the process of designing reservoir development for oil extraction, it is recommended to evaluate the activity of the hydrodynamic system. This highlights that the widely used methods are insufficient for comprehensive assessment and further review. As mentioned above, it is critically important to develop a scientific foundation and method for determining the activity of the hydrodynamic system in oil fields operating under water and elastic water pressure regimes.

The selection and scientific substantiation of the method for evaluating the activity of the reservoir's hydrodynamic system and its regimes operating with water and elastic water pressure.

Currently, one of the most common approaches to assessing the influence of various geological and physical factors in the process of oil field exploitation is the use of extrapolation methods, which are generally referred to as oil displacement methods in the oil and gas industry. Displacement characteristics refer to the different relationships between oil, water, fluid, or time factors. These displacement characteristics are divided into two main groups: the water saturation curve and the declining curve. The displacement characteristics can be determined using integral and differential methods.

The integral method of the water saturation curve is the relationship between the amount of oil extracted (water volume, fluid volume). The integral method of the declining curve is the relationship between the amount of oil extracted and time. Differential curves represent the relationship between current (e.g., monthly) oil extraction and time factors. Any displacement characteristic can be expressed in integral or differential form.

The water saturation curve applies to water-saturated wells (areas), while the declining curve corresponds to wells with low water or no water production. When evaluating the efficiency of the oil field development process, integral curves, which have less data on changes in water saturation and oil production volume, provide more accurate results. Another feature of integral curves is that they are less affected by random short-term fluctuations in the extraction process, as the changes in reservoir exploitation and volume are primarily related to the volume of oil production.

The displacement characteristic was first introduced by D.A. Efros, based on the relationship between the volume of oil extracted and the volume of fluid accumulated in the porous medium, expressed as Vn = f(Vsuy), which was later applied in practice. Subsequently, M.I. Maksimova, B.F. Sazonova, M.L. Surguchev, A.M. Pirverdyan, and other researchers widely used the displacement characteristic to analyze the development of oil fields and to forecast oil production. Typically, the displacement characteristic is constructed based on statistical data on oil, water, and fluid extraction from the reservoir over a certain period, and is then extrapolated for future periods. Therefore, the displacement characteristic is primarily used to predict oil production in the later stages of rational field development. Its application is very limited during the field design phase. This is primarily due to the lack of theoretical foundations for many displacement characteristics currently in use. At this point, creating a displacement characteristic for the development phase and field operation process should be based on theoretical concepts of fluid filtration in a porous medium.

Currently, most researchers apply the fundamental principles of Buckley-Leverette theory in their scientific works, which, without considering capillary effects, allows for the possibility of obtaining results that match both experimental and real data.

According to the methodological guidelines for calculating the oil recovery coefficients and the water displacement characteristics from the reservoir, the coefficients "a" and "b" are determined by separating the final part of the dynamic curve with a straight line.

To assess the activity of the hydrodynamic system, it is necessary to evaluate the amount of water flow (K_w) due to the accepted development system contour.

At the same time, the estimated amount of produced water is determined by comparing the estimated volume of water in the reservoir with the actual calculation of the flow coefficient, as defined by the following expression.

$$Q_{r.w} = Q_o(2R_{liq} - 1) \qquad 1.1$$

$$K_o = Q_{r.w} / Q_{d.w} \qquad 1.2$$

It should be emphasized that, in objects with an infiltration hydrodynamic system, the estimated value of the produced water is always higher than the determined value, meaning that it should be lower in objects with an Elysion hydrodynamic system.

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