Analysis of the Commercial Evaluation of Oil Deposits Using the Material Balance Method

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Abstract

The study of the commercial evaluation of oil deposits using the material balance method is currently extremely important for the energy industry, as it helps to optimize oil production processes, increase resource efficiency, and make informed decisions on field development in the context of a changing energy paradigm and aspirations for sustainable development. The purpose of this study is to investigate the method of commercial evaluation of oil deposits using the material balance. In this study, methods of analyzing geological data, mathematical modelling of deposits, calculating the material balance, and forecasting of oil production were used. As a result of the study of the commercial evaluation of oil deposits by the material balance method, it was found that this method helps to more accurately assess the initial oil reserves in the fields and effectively optimize their production processes, which is key to effective management of oil resources and ensuring the sustainable development of the oil industry. The results of the study showed that the method of commercial evaluation of oil deposits using the material balance provides an accurate assessment of the initial oil reserves in the fields and effectively considers changes in the volumes and properties of oil fluids during production, which is key to optimizing the processes of oil production and management of oil resources. The results of the analysis of changes in the field helped to determine the efficiency of oil production, identify the dynamics of changes in reserves, and forecast further production, which significantly affects management decision-making and planning for the development of oil projects, emphasizing the importance of the material balance method for the sustainable use of oil resources and efficient operation of fields.

Introduction

Oil continues to be one of the most important energy resources in the world, as it provides vital economic sectors such as energy production, transportation, and industry. In this regard, the importance of issues related to the evaluation of oil reserves, its efficient production, and sustainable use is growing. One of the most important methods of analyzing and measuring oil reserves in the fields is the commercial evaluation of oil deposits using the material balance method. The use of this method not only helps to accurately determine the initial oil reserves in the fields, but also to assess the effectiveness of its production processes, analyse the dynamics of changes in the field, and predict the volume of further production. These aspects play a key role in the management of oil resources and planning the development of the oil industry in the face of constant changes and challenges facing the energy industry.

The study of the commercial evaluation of oil deposits using the material balance method is important in the context of energy strategy and sustainable development. The need for such a study is conditioned by a number of

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factors. Oil is the main source of energy for many industries, transport, and household use, therefore, effective management of oil resources and optimization of their production are critically important for ensuring energy security and economic development. Given the changing climatic conditions and the desire to reduce the carbon footprint, efficient oil production and use require modern methods and technologies to minimise the negative impact on the environment. Thus, conducting a commercial evaluation of oil deposits using the material balance method is of strategic importance for the energy industry, the economy, and the environment, aimed at optimizing production processes, improving resource efficiency, and reducing negative environmental impacts.

The study of the commercial evaluation of oil deposits using the material balance method is an urgent topic reflected in the works of various researchers. Tlepov and Churikova (2023) focused on the evaluation of the effectiveness of methods for analyzing oil production in the fields. Issenov (2021) explored the impact of modern technologies on improving the accuracy of estimating oil reserves in fields. Lopes et al. (2021) aimed at forecasting the dynamics of changes in oil reserves. Imanbayev et al. (2022) analysed the efficiency and stability of the fields in the conditions of variable factors. Laherrère et al. (2022) conducted a comparative analysis of various methods of evaluating oil reserves. Cheng et al. (2022) investigated the issues of resource management in oil production. Tariq et al.(2021) analyzed the application for optimizing the processes of oil and gas production in various fields. Pang et al. (2021) investigated the influence of environmental factors on the assessment of oil reserves and developed methods for accounting for these factors. Askari et al. (2021) conducted an analysis of the efficiency of using various types of wells. Guo et al. (2022) explored the possibilities of application for optimizing oil production under various climatic and geological conditions. These papers generally show a wide range of interests and the relevance of the topic of commercial evaluation of oil deposits using the material balance method in the modern scientific environment. However, the problem requiring additional study is the gaps in understanding the influence of various factors, such as geological features of deposits and changes in the physicochemical properties of oil on the results of the evaluation using the material balance method. Further research in this area should be aimed at a deeper analysis of the relationships between various parameters and the development of improved methods for estimating oil reserves using the material balance.

The purpose of this study is to analyse the method of commercial evaluation of oil deposits using a material balance to improve the processes of extraction of oil resources and increase their efficiency in use.

Materials and Methods

Various methods were used to analyse the geological data, including geophysical and geochemical methods to investigate geological structures and field characteristics. These methods included collecting information on the distribution and properties of rocks, analyzing gravitational and magnetic fields, studying the composition of fluids and other techniques, which helped to more fully and accurately assess the geological situation and potential of the deposit. The application of such methods has made it possible to determine more precisely the geological features of the fields and their potential for oil production.

A comprehensive evaluation of the efficiency of the use of oil resources was carried out, which included an analysis of the results of calculations, modelling, and forecasting. This evaluation was aimed at determining the technical and economic efficiency of field development and the use of oil resources in the oil and gas industry. The analysis considered various aspects, including production volumes, development costs, technical capabilities, and economic indicators of projects. This provided informed decisions and helped to optimize the processes of extraction and use of oil resources to increase their efficiency and sustainability in the long term.

To carry out mathematical modelling of deposits, special models were created that reflected the geological structure and the main processes of oil production. These mathematical models allow analyzing various aspects of the behaviour of deposits in different time periods and predicting their dynamics in the future. The main purpose of using such models was to optimize development strategies based on the predicted characteristics and properties of deposits, which contributed to more efficient management of oil and gas production processes.

Forecasting of oil production on an industrial scale was carried out using the obtained data, models, and calculations. This included an assessment of future production considering various parameters such as reserves, technological capabilities, and economic factors. This approach helped to determine the technological and economic parameters of the projects, and to plan long-term strategies for field development. The forecasting results were used to make informed decisions on optimizing oil production and developing effective project management strategies in the oil industry.

To determine the volume and composition of oil reserves and production processes, calculations of the material balance were carried out. This process included an analysis of the initial hydrocarbon reserves in the reservoir, production volumes over time, and engineering parameters necessary to optimize production processes. Calculations of the material balance helped to more accurately evaluate the available oil and gas reserves, and predict and optimize the processes of their extraction from deposits. This is an important component of the planning and management of production operations in the oil industry.

An example of the successful application of the material balance method is illustrated by the evaluation of oil and gas reserves at four fields: Kumertau, Dolinsk, Cheleken, and Goturdepe. This evaluation was carried out by the State Commission on Mineral Reserves under the Cabinet of Ministers of Turkmenistan. Using the material balance method, it was possible to analyse and consider the entire life cycle of these deposits, starting from initial reserves to production and operation processes. This approach facilitated a more accurate evaluation of the resource potential of each deposit and helped to make informed decisions on their development and management.

Results

An example of a successful application of the material balance method is the evaluation of oil and gas reserves at four fields (Kumertau, Dolinsk, Cheleken, and Goturdepe) by the State Commission on Mineral Reserves under the Cabinet of Ministers of Turkmenistan (SCR). However, it should not be assumed that the material balance method will always be applied successfully [11]. Currently, the volumetric method of calculating oil and gas reserves is the most universal and should not be replaced by the material balance method. Nevertheless, given the expansion of pilot production and the increased possibilities of hydrodynamic and physicochemical studies of oil and gas deposits, the material balance method should be given more attention at the current stage of its development.

In the course of prospecting and exploration, it is necessary to collect and evaluate a number of key parameters for the successful assessment and further development of oil and gas deposits. It is important to determine the average initial reservoir pressure, which is achieved through measurements at several initial wells located at different elevations. It is also necessary to measure the average current reservoir pressure on deposits, regularly measuring the current pressures in technically sound wells during the operation of the field. To fully understand the characteristics of the deposit, it is also important to determine the saturation pressure of oil and gas at several points of the deposit, considering its hypsometric diversity (Al-Rubaye et al. 2021). The physicochemical properties of reservoir oils and gases also require special attention, including component composition, density, compressibility coefficients, gas solubility, and other parameters. This requires conducting research on deep samples of oil and gas from several wells, which will cover the entire thickness of the deposit. It is necessary to consider the production of oil, gas, and water from all wells within the reservoir, and to analyse the average initial and operational gas factors (Roozshenas et al. 2021). The analysis of the physicochemical properties of reservoir oil, including salts, gases, density and compressibility coefficients, requires a careful approach, and it is recommended to study deep samples of reservoir water. It is also necessary to investigate the compressibility of various lithological reservoir rocks, which is important for determining the effective volume of the deposit. Considering that most of these parameters are related to the volumetric method and are important for the development of oil and gas deposits, a more thorough approach to their research is required, which meets the basic requirements of the instructions on mineral reserves.

The definition of the material balance equation is based on one of the following two principles: preserving the mass and preserving the volume of pores that originally contained oil and gas. The first principle assumes that the amount of hydrocarbons or their weight remains unchanged in volume units during the extraction and production processes. The second principle indicates the preservation of the volume of pores that were originally filled with oil and gas in the deposits. Both of these principles serve as the basis for the development of material balance equations, which are used to analyse and predict the processes of production and operation of oil and gas fields.

In a reservoir with the initial presence of oil and gas, their amount, together with the extracted ones, should remain unchanged, which reflects the principle of conservation of mass (Xue et al. 2021). The preservation of the volume of pores initially filled with hydrocarbons is also always considered in the development of the reservoir, even with the possible occupation of part of the pore space with water. This method does not consider the influence of pore water, since it is assumed to be closely related to the rock, which does not affect the movement of oil, gas, and water. Thus, the material balance method is dynamic, reflecting the state of the reservoir depending on the dynamics of production and pressure changes. The equation of material balance can have different forms depending on the goals and conditions set by the authors at different times. Basically, the oil deposits of South-West Turkmenistan are developed under a mixed displacement regime (dissolved gas and high-pressure modes). For such deposits, the initial balance reserves of oil are calculated using the material balance method using the equation,

$$Q_o = \frac{Q_{o.p.}[b_1+(r_p-r_o)]v-(W-w)}{b_1-b_0}, \quad (1)$$

When conducting appropriate laboratory and field studies, the parameters included in this equation can be relatively easily obtained as of any date of deposit development. The only exception is the volume of water embedded in the deposit, which is practically impossible to determine directly. There are many methods for determining the volume of water embedded in the reservoir (Al-Shargabi et al. 2022). The volume of water embedded in the reservoir is most accurately and simply obtained based on the watered volume from the beginning of development to the calculation date; considering the initial and current oil content contours. For numerous reasons (multi-time flooding of reservoirs in facilities, lack of sufficient geophysical measurements in flooded areas), it is often not possible to determine the current contours of oil content. When determining the oil reserves of the deposits of South-West Turkmenistan (Cheleken, Goturdepe), a method obtained using mathematical statistics from the material balance equation and the equation for determining the volume of water embedded in the deposit is used. The volume of water embedded in the deposit is determined from the **Eq. 2**,

$$W = Q_{o.p.}b_0 + W - X(P_0 - P), \quad (2)$$

where X is determined based on the analysis of the development of productive formations in the initial stage of operation, by distinguishing the moment of drainage of deposits only in elastic and dissolved gas modes, when it can be assumed that the volume of water introduced is zero. A number of geological and energy features and conditions for entering deposits into development (insignificant oil-saturated volumes, the presence of bottom and intermediate waters, large fragmentation, unequal degree of activity of contouring waters, simultaneous commissioning of most wells within a short time) do not allow confidently distinguishing the time of manifestation of drainage regimes throughout the entire volume of operational facilities. In this regard, Eq. 2 can be used in a different way. Substituting **Eq. 3** into **Eq. 1**,

$$Q_o = \frac{Q_{o.p.}[(b_1-b_0)+(r_p-r_o)v]}{b_1-b_0} + X\frac{P_0-P}{b_1-b_0}, \quad (3)$$

or

$$Q_o = Q_{o.p.}\left[1+\frac{(r_p-r_o)v}{b_1-b_0}\right] + X\frac{P_o-P}{b_1-b_0}. \quad (4)$$

In **Eq. 4**, the values of the initial balance reserves of oil (Q_o) and the specific elastic capacity are constant, and the variables are – $Q_{o.p.}\left[1+\frac{(r_p-r_o)v}{b_1-b_0}\right]$ and $\frac{P_o-P}{b_1-b_0}$. Then, separating the variables,

$$Q_{o.p.}\left[1+\frac{(r_p-r_o)v}{b_1-b_0}\right]=Q_o-X\frac{P_o-P}{b_1-b_0}, \quad (5)$$

or denoting,

$$y=\ Q_{o.p.}\left[1+\frac{(r_p-r_o)v}{b_1-b_0}\right], \quad (6)$$

$$Z=\frac{P_o-P}{b_1-b_0}, \quad (7)$$

obtain,

$$y=\ Q_0-X_Z \quad (8)$$

Since the field data and the data of deep samples carry certain errors, when determining the value of balance reserves, it is most rational to use the methods of mathematical statistics, making calculations for several dates. In this case, using the least squares method, *X* is defined from the expression,

$$X=-\frac{n\sum YZ-\sum Y\sum Z}{n\sum Z^2-(\sum Z)^2}, \quad (9)$$

where *n* represents the sample size (the number of dates for which calculations are performed to determine reserves).

Substituting the values of *Y* and *Z* in **Eq. 9**,

$$X=\ \frac{-n\sum Q_{o.p.}\left[1+\frac{(r_p-r_0)v}{b_1-b_0}\right]\frac{P_0-P}{b_1-b_0}+\sum Q_{o.p.}\left[1+\frac{(r_p-r_0)v}{b_1-b_0}\right]\sum\frac{P_0-P}{b_1-b_0}}{n\sum\left(\frac{P_0-P}{b_1-b_0}\right)^2-\left(\sum\frac{P_0-P}{b_1-b_0}\right)^2} \quad (10)$$

Substituting the value of *X* found in this way into **Eq. 8**, we obtain Q_o,

$$Q_0=\ \frac{\sum Y}{n}+X\frac{\sum Z}{n}, \quad (11)$$

or

$$Q_0=\ \frac{\sum Q_{o.p.}\left[1+\frac{(r_p-r_0)v}{b_1-b_0}\right]}{n}+\ X\frac{\sum\frac{P_0-P}{b_1-b_0}}{n} \quad (12)$$

Substituting formula 5 into formula 9, an equation is derived that determines the initial balance reserves of oil without determining the specific elastic capacity,

$$Q_0=\ \frac{\sum Q_{o.p.}\left[1+\frac{(r_p-r_0)v}{b_1-b_0}\right]\sum\left(\frac{P_0-P}{b_1-b_0}\right)^2\sum Q_{o.p.}\left[1+\frac{(r_p-r_0)v}{b_1-b_0}\right]\left(\frac{P_0-P}{b_1-b_0}\right)\sum\frac{P_0-P}{b_1-b_0}}{n\sum\left(\frac{P_0-P}{b_1-b_0}\right)^2-\left(\sum\frac{P_0-P}{b_1-b_0}\right)^2} \quad (13)$$

In the presence of a gas cap, Eqs. 1 and 2 will take the following form,

$$Q_o=\ \frac{Q_{o.p.}[b+(r_p-r_o)]v-(W-w)Q_{g.}(v-v_o)}{b_1-b_0}, \quad (14)$$

$$W=Q_{o.p.}b_0+w-Q_{\text{г}}(v\ -\ v_0)-X(P_0-P), \quad (15)$$

where, $Q_{g.}$ *Is* gas reserves of the gas cap; υ_0 is volume coefficient of the gas at the initial reservoir pressure.

Therefore, the proposed method for determining the initial balance reserves of oil can be applied to a complex reservoir with free gas. The undeniable advantage of this technique is that the extracted water, which in many cases includes hydrodynamically "foreign" water, does not affect the amount of balance reserves. **Table 1** provides an example of calculating the initial balance reserves of oil using this method. The inventory is calculated for 5 dates. When choosing dates, it is necessary to consider the specifics of the development of deposits; the proposed technique gives the most correct results during the development of the object with the predominant development of the dissolved gas regime. Thus, this technique helps to determine the initial balance reserves of oil without first determining the volume of water embedded in the deposit and the specific elastic capacity of the deposit (formation and reservoir fluid). It boils down to establishing a pattern between two complex variables: $Q_{o.p.} = \left[1 + \frac{(r_p - r_o)v}{b_1 - b_0}\right]$, characterising the released volume in the process of oil production; $\frac{P_0 - P}{b_1 - b_0}$, characterising the degree of drop in reservoir pressure due to oil extraction and degassing.

The main task in calculating stocks using this method is to select the dates for which calculations are made. To do this, it is necessary to analyse the drainage regime based on the data from the exploitation of oil deposits and field studies. The analysis showed that the nature of the drainage regime transition is mainly preserved (Table 1). In the initial stage, a predominantly elastic drainage regime develops. During this period, the reservoir pressure is higher than the saturation pressure. Due to the fact that in some wells or zones the reservoir pressure falls below the saturation pressure, although the weighted average reservoir pressure is higher than the saturation pressure, the gas factor increases, and the dissolved gas regime participates in oil recovery. During this period, the deposit is usually not fully drilled, the calculation of reserves for this period leads to underestimated results, since instead of the initial balance reserves of oil, the drained part is determined.

The beginning of the second period is the moment when the reservoir pressure drops to saturation pressure. This period is characterised by an increase in the magnitude of the gas factor. After a certain time has elapsed, depending on the reservoir filtration properties, the rate of drilling and development of the deposit, the value of the gas factor stabilises, and then begins to fall. Usually during this period, the facility is fully drilled, and all balance reserves are under development. The end of this period is the beginning of the intensive introduction of water, characterised by an increase in the water content in the production of wells. This is the beginning of the third period – the period of displacement of carbonated oil by water.

The second period meets all the requirements of the proposed methodology, therefore, reserves are calculated according to the development data of this period. Thus, the dates for calculating reserves should cover the period of deposit development from the moment of comparing the current reservoir pressure with the critical saturation pressure to the moment when the share of the dissolved gas regime in oil displacement decreases. In this case, the interval between the counting dates is taken, based on the duration of the period under consideration, from 0.5 to 1 year.

As already noted, the proposed method represents the equation of material balance in the form of a straight line and is based on finding the unknown (Q_o) of this equation. In this case, the variables are the indicators $Q_{o.p.} = \left[1 + \frac{(r_p - r_o)v}{b_1 - b_0}\right]$ (conventionally denoted as indicator A), and $\frac{P_0 - P}{b_1 - b_0}$ (conditionally–indicator B). The graph of the relationship between these indicators has a broken character, moreover, with a decrease in indicator B, indicator A grows (**Figure 1**).

Table 1—Example of calculating the initial balance reserves of oil.

Date	Accumulated oil production $Q_{a.p.}$, thousand tonnes	Oil production due to elastic mode $Q_{o.e.}$, thousand tonnes	$Q_{o.p.}=Q_{a.p.}-Q_{o.e.}$, thousand tonnes	Accumulated gas production $Q_{a.g.}$, thousand m^3	Oil production due to the elastic mode $Q_{g.e.}$, thousand m^3
1	124.3	108.8	15.5	104,877	85,324
2	150.9		42.1	136,325	
3	181.9		73.1	173,261	
4	210.5		101.7	197,803	
5	233		124.2	214,655	
The volume coefficient of the gas υ	Gas content in reservoir oil, m^3/m^3	$b_1=b+(r_0-r)\,υ$	b_1-b_0	$Q_{o.p.} = \left[1 + \frac{(r_p - r_o)v}{b_1 - b_0}\right]$	$\frac{P_0 - P}{b_1 - b_0}$
1.4927	172.9	1.6412	0.0592	1,070.4	1,081
1.4007	134.6	1.7626	0.1806	1,122.3	719.8
1.3589	117.2	1.8693	0.2873	1,415.8	556.9
1.3338	106.8	1.953	0.371	1,522.6	479.8
1.317	99.8	2.0333	0.4513	1,557.6	421
Date	$Q_{o.p.}=Q_{a.p.}-Q_{o.e.}$, thousand m^3	$Q_{o.p.}$, thousand m^3	Average gas factor, g_p, m^3/m^3	Current reservoir pressure P, atm	Volume coefficient of gas, $υ$
1	19,553	18.8	1,037.8	286	0.004
2	51,001	51.2	996.6	220	0.0048
3	87,937	88.9	989.7	190	0.0055
4	112,479	133.6	909.7	172	0.006
5	129,331	151	856.7	160	0.0065
Date	Volume coefficient of the gas, $υ$	Balance oil reserves according to the calculation of $Q'_{o.p.}$, thousand m^3/thousand tonnes		Initial balance reserves of oil $Q_0 = Q_0 + Q_{o.e.}$, thousand tonnes	
1	1.4927	1,878.2		1,654	
2	1.4007	1,545.2			
3	1.3589				
4	1.3338				
5	1.317				

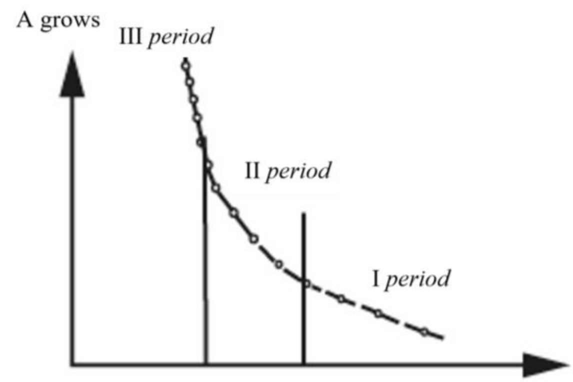

Figure 1—Diagram of changes $Q_{o.p.} = \left[1 + \frac{(r_p - r_o)v}{b_1 - b_0}\right] = f\left(\frac{P_0 - P}{b_1 - b_0}\right)$.

In the initial period of deposit development, the growth rate of indicator A is the lowest. The calculation of reserves for this period gives drained oil reserves, not true balance reserves. During the transition to the second period – the period of operation of the deposit under the dissolved gas regime – the growth rate of indicator A increases. This indicates the drainage of all balance oil reserves. In the third period, the indicator under study grows much steeper, due to the intensive introduction of marginal or underlying water into the oil part. Thus, the correctness of the choice of dates for which reserves are calculated and which are substantiated by the analysis of the development of the deposit can be verified by building a relationship between indicators A and B.

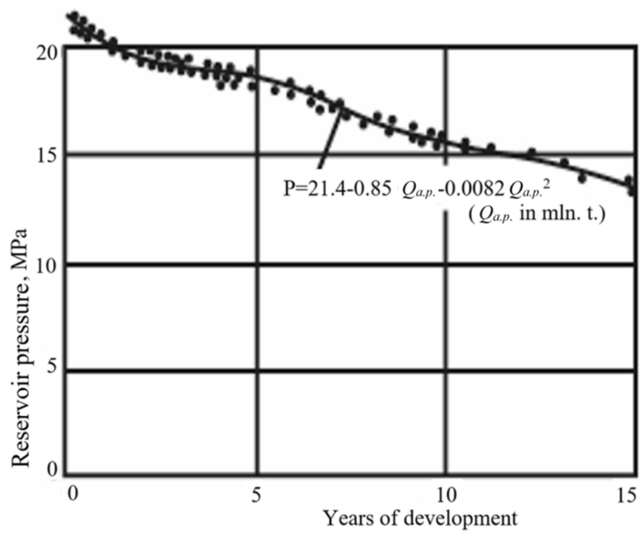

Figure 2—Dynamics of reservoir pressure.

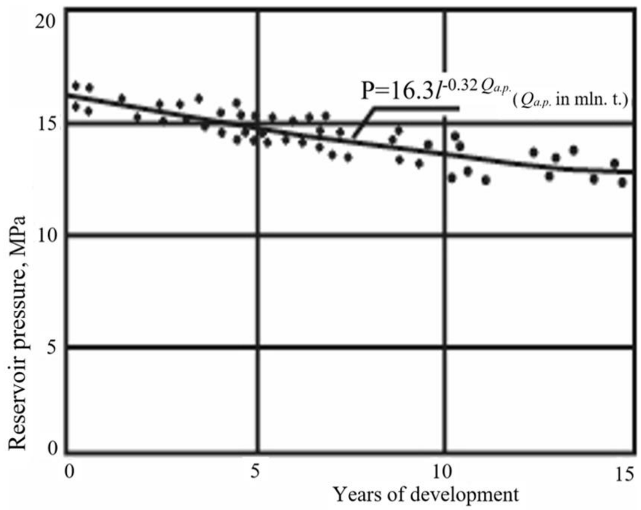

Figure 3—Dynamics of reservoir pressure.

An equally important role in calculating oil reserves by the material balance method is played by the correct determination of the average reservoir pressure of the counting object and saturation pressure (Fuentes-Cruz and V ásquez-Cruz 2022). The traditional way to determine the average reservoir pressures is to build isobar maps. In cases where there is no possibility (insufficient number of measurements on one date) or there is no need (does not lead to clarification of the average reservoir pressure), a correlation dependence of its drop in the process of oil recovery is found to predict reservoir pressure. It has been revealed that the drop in reservoir pressure is described by the parabola equation, power or exponential equations, and rarely by the equation of a straight line (**Figures 2 and 3**). Usually, the correlation dependence of the reservoir pressure drop is found over time (Sami and Ibrahim 2021). Such dependencies do not consider the “peaks” and drops in oil production, but smooth them out and, therefore, when calculating for these dates, especially when calculating reserves using the material balance method, they can lead to significant errors. Therefore, at present, the correlation dependence of the drop in reservoir pressure of deposits in South-West Turkmenistan is determined not by time, but depending on the accumulated production of oil ($Q_{a.p.}$). To do this, a graph of the reservoir pressure drop over time is plotted (Figures 2 and 3), and the accumulated production of oil is considered in the calculations. Then, based on the characteristics of the dependence, the regression equation is selected. As a rule, this is a second-order equation,

$$P = a + a_1\, Q_{a.p.} + a_2 Q^2{}_{a.p.} \quad \text{.......}(16)$$

In cases where the dependence obeys the equation of a straight line, the coefficient a_2=0. The unknowns a, a_1, and a_2 are determined from expressions derived using the least squares method,

$$a_2 = \frac{\left[\sum Q^2_{a.p.} \frac{\left(Q^2_{a.p.}\right)^2}{n}\right]\left[\sum Q^2_{a.p.} P - \frac{Q^2_{a.p.} \sum P}{n}\right] - \left[\sum Q_{a.p.} P - \frac{\sum Q_{a.p.} \sum P}{n}\right]\left[\sum Q^3_{a.p.} P - \frac{\sum Q^9_{a.p.} \sum Q_{a.p.}}{n}\right]}{\left[\sum Q^2_{a.p.} - \frac{\left(Q^2_{a.p.}\right)^2}{n}\right]\left[\sum Q^4_{a.p.} - \frac{\left(Q^2_{a.p.}\right)^2}{n}\right] - \left[\sum Q^3_{a.p.} - \frac{Q^2_{a.p.} \sum Q_{a.p.}}{n}\right]^2}, \quad \text{.......}(17)$$

$$a_1 = \frac{\left[\sum Q^4_{a.p.} \frac{\left(Q^2_{a.p.}\right)^2}{n}\right]\left[\sum Q^2_{a.p.} P - \frac{\sum Q_{a.p.} \sum P}{n}\right] - \left[\sum Q^2_{a.p.} P - \frac{Q^2_{a.p.} \sum P}{n}\right]\left[\sum Q^3_{a.p.} P - \frac{\sum Q^2_{a.p.} \sum Q_{a.p.}}{n}\right]}{\left[\sum Q^2_{a.p.} - \frac{\left(Q_{a.p.}\right)^2}{n}\right]\left[\sum Q^4_{a.p.} - \frac{\left(Q^2_{a.p.}\right)^2}{n}\right] - \left[\sum Q^3_{a.p.} - \frac{Q^2_{a.p.} \sum Q_{a.p.}}{n}\right]^2}, \quad \text{.......}(18)$$

$$a = \frac{\sum P}{n} - a_1 \frac{\sum Q_{a.p.}}{n} - a_2 \frac{\sum Q^2_{a.p.}}{n}, \quad (19)$$

where, n indicates the number of reservoir pressure measurements for wells.

The drop in reservoir pressure also obeys the equations,

$$P = a\, Q_{a.p.}^{-a}, \quad (20)$$

$$P = al^{-a_1 Q_{a.p.}} \quad (21)$$

Logarithmising these equations, respectively, obtain

$$lg\ P = lg\ a - a_1\ lg\ Q_{a.p.}, \quad (22)$$

substituting

$$lg\ P = P', \text{and } lg\ a = a', \quad (23)$$

into:

$$lg\ Q_{a.p.} = Q'_{a.p.}, \text{and } a_1 lgl = a_1 \quad (24)$$

$$p' = a' - a_1 Q'_{a.p.} \quad (25)$$

$$p' = a' - a_1 Q_{a.p.} \quad (26)$$

Calculations by determining the unknowns a_1, a^1 and a_1^1 of these equations can be performed using dependencies Eqs. 18 and 19, setting $Q^2_{a.p.} = 0$ (he condition for obtaining a_2=0) и a_2=0. When describing the drop in reservoir pressure by the parabola equation, at different signs between a_1 and a_2, it is necessary to determine the limits of its applicability. To do this, **Eq. 16** is differentiated and equated to zero as

$$P' = a_1 + a_2 Q_{a.p.} = 0 \quad (27)$$

Hence, the cumulative oil production up to which the found correlation equation is valid will be

$$Q_{a.p.} = -\frac{a_1}{2a_2} \quad (28)$$

Processing data from reservoir pressure measurements to establish one or another dependence and comparing these dependencies is a time-consuming calculation work. Processing of this data on modern computing tools significantly speeds up this process and further increases the reliability of choosing one or another dependence. The saturation pressure is usually determined by averaging data from deep field sampling studies. This method does not consider the nature of the change in saturation pressure, both in area and in power. As is known, for an oil and gas deposit, the maximum saturation pressure equal to the initial reservoir pressure of the gas cap is observed on the surface of the gas-oil contact. Moving away from the gas-oil contact, both in area and in power (in depth), the saturation pressure decreases (Wang et al. 2023).

The results of actual measurements are taken as initial data, as well as data determined according to the methodology. According to this method, the dependence of saturation pressure on:

1. Distance (vertically) between the GOC plane and the average level of the oil saturated layer (O).
2. Distance (horizontally) between the initial position of the GOC and the well (ℓ). The equation of this dependence is found in the form,

$$P_{sat.} = P_{sat.max} + C_1 H + C_2 \ell, \quad (29)$$

where, $P_{sat.max}$ is the maximum saturation pressure; C_1, C_2 are coefficients.

Therefore, the equation determined the value of saturation pressures for wells in which there are no actual measurements. As practice has shown, the difference between saturation pressures, defined as arithmetic mean and weighted average values, for highly productive facilities reaches 10 atm. (MPa), which significantly affects the determination of accumulated oil and gas recovery, initial values of the volume coefficient, and the gas content of oil. There is another way to determine the saturation pressure, which is based on the results of laboratory studies to determine the dependence of the volume coefficient (b) and the gas content (r) of oil on the pressure drop of oil taken from the first wells of each horizon.

Based on the results of these studies, a graph is constructed (**Figure 4**). It can be seen from these graphs that there is an area where b and r are practically constant, despite the drop in reservoir pressure. After reaching the critical pressure, the values of the gas content and the volume coefficient begin to fall, obeying the equation of the straight line. As the practice of studying deep samples has shown, this equation is valid up to 50 atm (5 MPa), sometimes up to 30 atm (3 MPa).

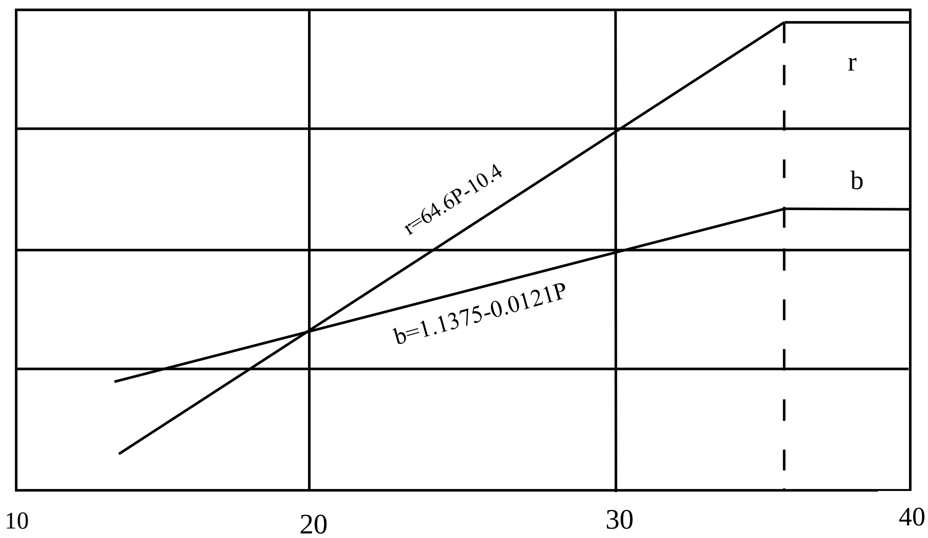

Figure 4—Change in the volume coefficient and gas content of oil from pressure.

This critical pressure is the saturation pressure. Not all operational facilities can identify the transition zone and determine P_{sat}, which is due to many geological reasons, as a result of which the selected deep sample does not characterise the initial equilibrium state of the gas and oil system. But despite this, these graphs reflect the dependence of b and r on pressure and are used to determine them at various stages of development. When calculating oil reserves using the material balance method, correlation equations of these dependencies are usually used,

$b = a + a_1 P$,..(30)

$r = a^1 + a_1 P$..(31)

Substituting reservoir pressure values in **Eqs. 30** and **31**, it is easy to determine b and r for this period at various stages. The determination of the initial volume coefficient (b_0) and gas content (r_o) is carried out in the same way, only instead of reservoir pressure in Eqs. 30 and 31, the value of the critical saturation pressure ($P_{sat.}$) is set. The objects of operation at the Nebit-Dag and Cheleken fields, which were put into operation in the period before the war and during the Second World War, did not take deep samples at the time. For such objects, the dependences of the drop b and r on pressure are calculated. In West Turkmenistan, such calculations were carried out for the first time when calculating the reserves of the Cheleken deposit, the results of which were approved by the State Reserves Committee of the Union of Soviet Socialist Republics (Deryaev 2023). Below is an example of determining the dependencies of the volume coefficient and the gas content of oil on pressure for one of the calculation facilities of the Cheleken field. Calculations are made based on data on the fractional composition of the gas.

0.0

The study determines the volume of oil in reservoir conditions, if it occupies 1 m^3 on the surface, at a saturation pressure P_{sat} is 26 MPa, oil density is 0.82 t/m^3, reservoir temperature is 75°C. Based on these data, according to the Standing's nomogram (**Figure 5**), the gas content of oil is determined to be 157.5 m^3/m^3. Based on the volume content of the gas, the gas content, and the mass and volume of the gas in the liquid phase, the mass of the gas components and their volume in the liquid phase are determined, assuming that the weight of the gas in the formation is dissolved in oil (**Table 2**).

Table 2—Mass of gas components and their volume in the liquid phase.

Components	Mass of individual gas components per 1 m^3 of oil, kg	Volume of components in the liquid phase per 1 m^3 of oil, l
Methane	0.8943*157.5*0.714=100.9	0.8943*157.5*2.26=319.3
Ethane	0.0445*157.5*1.35=9.5	0.0445*157.5*3.36=25.6
Propane	0.0258*157.5*1.97=8	0.0258*157.5*3.66=15
Butane	0.015*157.5*2.85=6.8	0.015*157.5*4.2=10
Pentane	0.0072*157.5*3.22=3.7	0.0072*157.5*4.85=5.5
Hexane+higher	0.0036*157.5*3.81=22	0.0036*157.5*5.49=3.1
Carbon dioxide	0.0029*157.5*1.25=0.6	0.0029*157.5*0=0
Nitrogen	0.0067*157.5*1.964=2.1	0.0067*157.5*1.19=1.2
Oil	820.6	1,000
Total	954.2	1,377.7

Thus, the volume of 1 cubic metre of oil with dissolved gas in reservoir conditions is 1.3777 m^3, and its mass is 954.2 kg. However, due to the fact that the reservoir temperature for ethane and methane is above their critical temperature, these gases are in a dissolved state in reservoir oil, and not in liquid.

The density of the ethane + higher mixture was determined, and then, using the value, the density of the reservoir oil was determined. The mass of the components from propane and above is equal to (Table 2),

954.2-(100.9+9.5)=843.8 kg..(32)

and the volume of these components is,

1,377.7-(319.3+23.6)=1,034.8 ....(33)

The density of the mixture from propane and above will be,

$$\frac{843.8}{1{,}034.8} = 0.815 \quad (34)$$

Percentage of ethane in the mixture of hydrocarbons ethane + higher is,

$$\frac{9.5*100}{954.2-100.9} = 1.11\% \quad (35)$$

Figure 6 shows the density of the mixture ethane + higher is 0.792 t/m^3. To calculate the density of oil, the percentage of methane in the hydrocarbon mixture consisting of methane and higher hydrocarbons is determined,

$$\frac{100.9*100}{954.2} = 10.6\% \quad (36)$$

Figure 7 shows the density of reservoir oil as 0.68 tonnes/m^3. This value requires correction to account for the compressibility of the liquid and its thermal expansion. The compressibility correction is 0.027. Therefore, considering this correction, the density of oil in the reservoir will be equal to

0.680+0.027=0.707 t/m^3...(37)

The correction to the density of formation oil due to temperature change is determined, which is 0.05. Consequently, the density of oil will be

0.707-0.05=0.657 t/m^3..(38)

The gas content of the Standing's nomogram will be 80 m^3/m^3 (Figure 5).

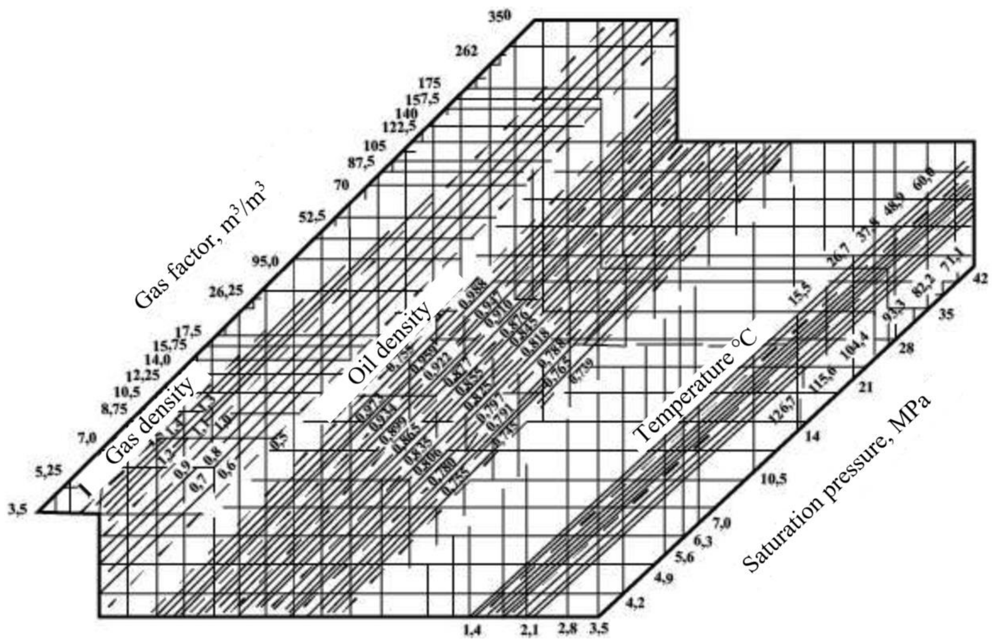

Figure 5—Standing's nomogram (Source: Guo et al. 2022).

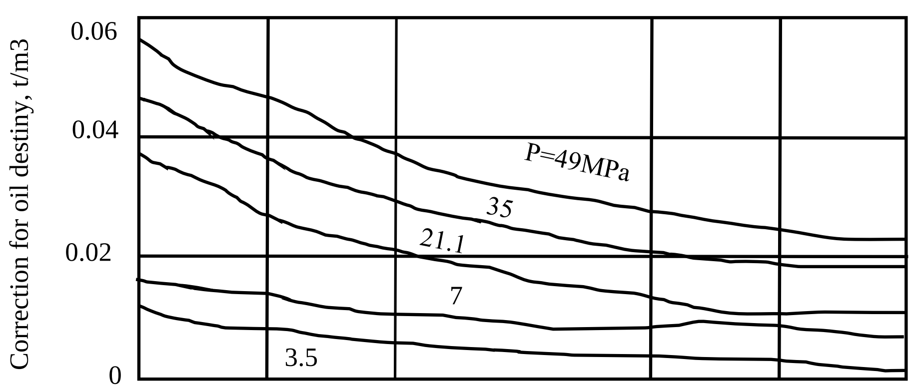

Figure 6—Determination of correction for reservoir oil compressibility.

Considering that the mass of 1 cubic metre of oil in reservoir conditions is 962.7 kg, its volume will be equal to 1,452 litres, assuming a density of 0.657. Hence, the volume coefficient of oil, calculated from the data of the fractional composition of gas, is equal to 1,452/1,000=1.452. Since the change in the volume coefficient and gas content of oil from pressure obeys the equation of a straight line, it is sufficient to determine their values for another arbitrarily selected point of reservoir pressure, for example 14 MPa. The mass and volume of gas components in the liquid phase are determined (**Table 3**).

Table 3—Mass and volume of gas components in the liquid phase.

Components	Mass of individual gas components per 1 m^3 of oil, kg	Volume of components in the liquid phase per 1 m^3 of oil, l
Methane	62.2	197.1
Ethane	5.9	14.6
Propane	5	9.2
Butane	4.2	6.1
Pentane	2.2	3.4
Hexane+higher	1.3	2
Carbon dioxide	0.4	-
Nitrogen	1.2	0.8
Oil	820.6	1,000
Total	903	1,233.2

The mass and volume of the components from propane and above, respectively, are 834.9 kg and 1021.5l, therefore, the density will be 0.817. Based on the density of the mixture and the percentage of ethane (0.7%), the density of the ethane + higher mixture was found to be 0.795. Figure 7 denotes the density of oil by the calculated value of the density of the mixture (0.795) in the methane content (6.9%). It is 0.726 t/m^3. The correction for compressibility is 0.011, and for expansion is 0.046. Ultimately, the density of oil will be 0.691 t/m^3. Then the volume coefficient will be 1.307. Based on these two points, the dependencies between the volume coefficient and the gas content of oil and pressure are determined using mathematical statistics in the following form,

$$b = 1.1378 + 0.0121\mathrm{P}_{res.}, \quad (39)$$

$$r = 6.46\ \mathrm{P}_{res.} - 10.4[m^3/m^3] \quad (40)$$

The volume coefficient of the gas is also determined based on the fractional composition of the gas. To do this, first of all, pseudocritical pressures (P_r) and temperature (T_r) are determined (**Table 4**).

Table 4—Determination of pseudocritical pressures and temperatures.

Components	Content of the mixture, C_i, %	Critical absolute pressure, P_i, MPa	Critical temperature, T_i, °K
Methane	92.99	4.58	190.5
Ethane	2.29	4.82	305.28
Propane	1.21	4.2	369.78
Butane	0.42	3.64	4.07
Pentane	0.94	3.747	425
Hexane+higher	0.71	3.29	460.78
Carbon dioxide	0.18	7.29	304.1
Nitrogen	1.26	3.349	126

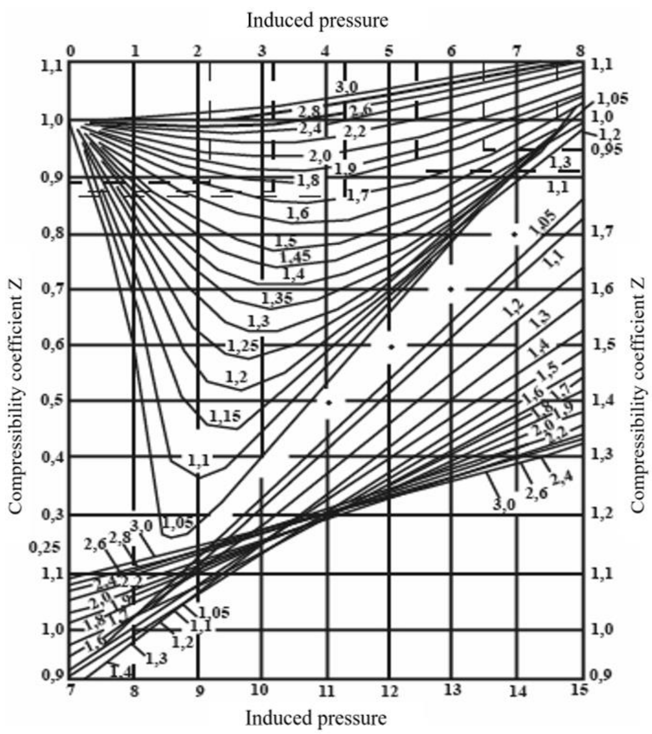

Figure 7—Graph for determining the compressibility factor.

The pseudocritical pressure and temperature were determined by the equations (Table 4):

$$P_r = \sum \frac{P_i C_i}{100\%} = 4.64\ MPa, \quad (41)$$

$$T_r = \sum \frac{T_i C_i}{100\%} = 200°K \quad (42)$$

Further, the given pseudocritical pressures and temperatures were determined,

$$P_R = \frac{P_{res.}+1}{Pr}, \quad (43)$$

$$T_R = \frac{T_{res.}}{T_r} = \frac{70^{\circ}C+273}{200^{\circ}} = 1.715 \qquad (44)$$

The reduced pseudocritical pressure is determined at various reservoir pressures (**Table 5**).

Table 5—Presented pseudocritical pressure at different reservoir pressures.

Reservoir pressure, $P_{res.}$, MPa	35	30	25	20	15	10
Reduced pseudocritical pressure, P_r	7.6	6.5	5.4	4.3	3.2	2.2
Compressibility factor, Z	1.01	0.95	0.91	0.87	0.88	0.89
Volume coefficient of gas, υ	0.00346	0.0038	0.00436	0.00521	0.00702	0.01073

The compressibility factor (Z) is determined based on (Figure 5), the accuracy of which is 1%. The volume coefficient of the gas was determined using the formula,

$$v = 0.000352Z\frac{T_{res.}}{P_{res.}} \qquad (45)$$

As the results of subsequent studies have shown, the presence of nitrogen in the gas up to 19% increases the error to ±2%, and the content of CO_2 and H_2 more than 2% requires appropriate corrections when introduced (Figure 7). The gases of the deposits under study contain 1-1.5% nitrogen, CO_2 0.15-0.3%, and the amendments become impractical (**Figure 8**).

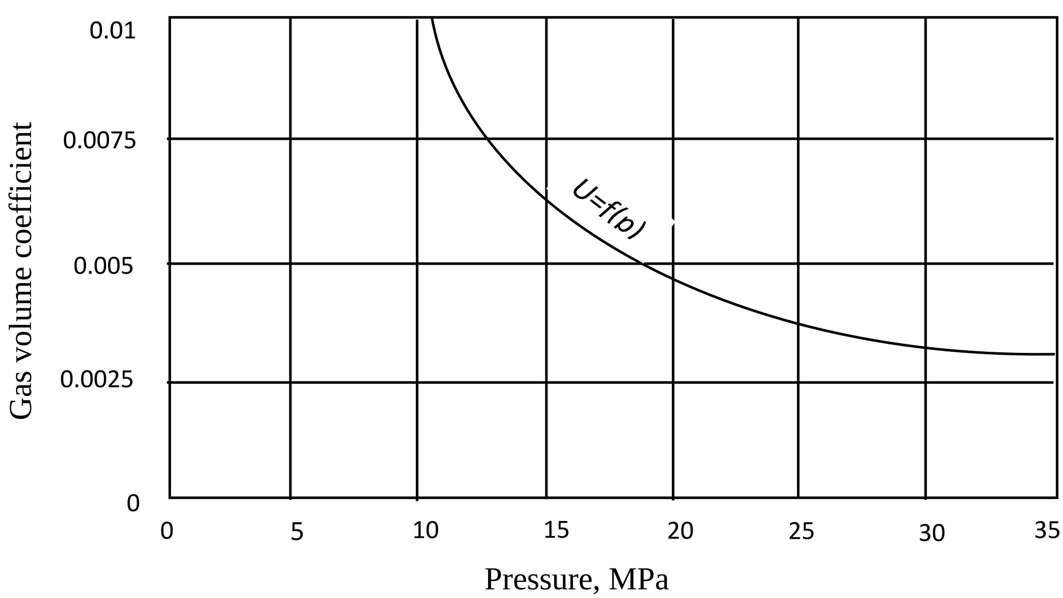

Figure 8—Change in the volume coefficient of gas from pressure.

The gas factor plays an important role in calculating reserves. During the development of oil deposits with a gas cap, as the reservoir pressure drops in the extraction zone (in the oil part), the gas cap expands, which leads to gas contamination of well products, and sometimes gas cap gas breakthrough (development of so-called “gas cones”).

The gas breakthrough from the gas cap, in addition to the deterioration of the oil recovery process, makes it difficult to determine the value of the true gas factor, which is the most important technological parameter of the deposit operation (Wen et al. 2023). Naturally, failure to account for a gas breakthrough can lead to significant errors both in substantiating geological and technical measures for rational development and in assessing oil and gas reserves. For example, failure to account for a gas breakthrough can lead to an increase in the balance reserves of oil, and therefore dissolved gas, when calculated using the material balance method by several (sometimes dozens) times. When evaluating the reserves of oil deposits in Western Turkmenistan, a methodology was used to assess the true gas factors and its changes (dynamics) in the process of oil recovery based on actual development materials based on establishing the relationship between gas content, gas factor, and current reservoir pressure.

Under the condition of uniform reduction of reservoir pressure in all areas of the deposit, the value of the gas factor is determined by the gas content and the ratio of the current reservoir pressure and saturation pressure (Wang et al. 2022). Due to the decrease in reservoir pressure during development below the saturation pressure, as is known, a more intensive release of dissolved gas from oil occurs in the reservoir. However, the gas factor exceeds the gas content of oil, and the degree of its excess is determined mainly by the ratio of reservoir pressure and saturation pressure. Based on the actual data of the development of operational facilities of the Goturdepe field: graphs of the relationship between the ratio of the gas factor to the gas content $-\frac{r_p}{r}$ and reservoir pressure to saturation pressure–$P_{res.}/P_{sat.}$ Processing of the actual data on the second group of deposits provides the following dependence,

$$\frac{r_p}{r} = 1 + 90.47^{-6.1225 P_{res.}/P_{sat.}} \quad (46)$$

With a significant drop in reservoir pressure ($P_{res.}/P_{sat.} \leq 0.6$), the proposed correlation relationship gives overestimated results. This is explained by the fact that at this time, the formation of secondary gas caps is observed in the studied objects and, naturally, an increase in the gas factor. To exclude this phenomenon, the gas factors were calculated from the expression,

$$r_p = \frac{Q_0 r_0 - Q_{resid.} 2}{Q_{o.p.}}, \quad (47)$$

where, Q_o is initial balance reserves of oil; $Q_{resid.}$ Is residual oil balance reserves; Q_m is accumulated oil production; r_0 is initial gas content; *r is* current gas content.

As can be seen from **Figure 9**, the curves characterising these dependencies are divided into two groups. The first is characterised by a sharp incommensurable excess of the gas factor over the gas content with a slight decrease in reservoir pressure below the saturation pressure. This group includes deposits, obviously, a sharp increase in the gas factor is determined by the flow of gas from the gas cap into production wells. Another group of curves, which includes deposits that do not have a gas cap, is characterised by a comparative slope to the left. The excess of the gas factor over the gas content here is determined precisely by the degree of reduction of reservoir pressure below the saturation pressure, that is, the degree of degassing of reservoir oil (Mullins et al. 2023). A similar graph was constructed using calculated gas factors (**Figure 10**).

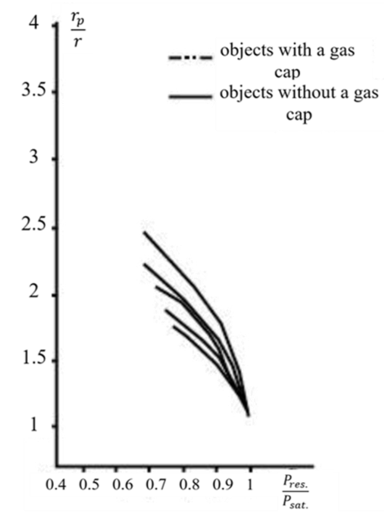

Figure 9—Relationship between the ratio of the gas factor to the gas content.

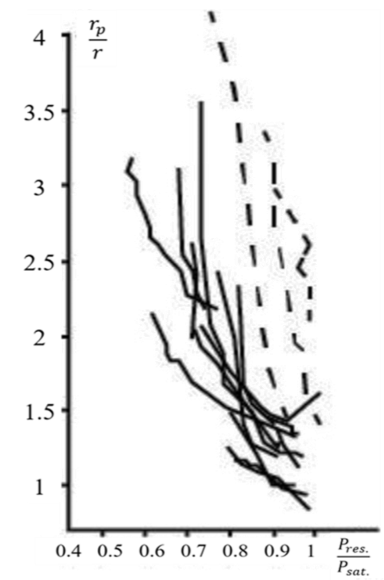

Figure 10—Dependence of reservoir pressure on saturation pressure.

When processing this data, the following dependence was obtained,

$$\frac{r_p}{r} = 5.028 - 4.28\frac{P}{P_{sat.}} + 0.48\left(\frac{P}{P_{sat.}}\right)^2 \quad (48)$$

This dependence gives correct results even at $P_{res.}/P_{sat.}$=0.4 and below. Thus, when developing oil and gas deposits, the following method is proposed for determining the volume of associated gas that broke out of the gas cap during oil recovery (Soomro et al. 2022):

1. With known values of reservoir pressure and gas content, the above dependencies determine the possible value of the true gas factor, the average for the entire period of development, and through it the accumulated production of dissolved gas.

2. The volume of associated gas released from the gas cap is defined as the difference between the measured and calculated values of gas production.

The determination of recoverable oil reserves (oil recovery coefficient) can also be performed using the material balance method. For this purpose, the so-called displacement indices are determined, which show the share of participation of each regime in the oil production process. Displacement index of the water pressure regime: $I_{w.r.} = \frac{W-w}{Q_{o.p.}\left[b_1+(r_p-r_0)v\right]}$ ($I_{w.r.}$:water regime displacement index). Displacement index of the dissolved gas regime: $I_{d.g.} = \frac{Q_0(b_1-b_0)W-w}{Q_{o.p.}\left[b_1+(r_p-r_0)v\right]}$ ($I_{d.g.}$:dissolved gas mode displacement index). The displacement index of the gas cap regime: $I_{g.c.} = \frac{Q_{g.}(v-v_0)W-w}{Q_{o.p.}\left[b_1+(r_p-r_0)v\right]}$ ($I_{g.c.}$:displacement index of the gas cap regime).

The sum of the displacement indices of all regimes involved in the development of the deposit should be 1. Displacement indices characterise not only the drainage regime, but also the proportion of oil, and the volume of deposits that are influenced by one or another regime. If a deposit is developed under a mixed regime, then each area (part of the oil) will be characterised by its own oil recovery coefficient, more or less (based on other geological and field conditions) different from the oil recovery of other areas. In this case, the oil recovery coefficient for the deposit, in general, will be determined based on the displacement indices and based on the oil recovery coefficients, from the conditions of development of the deposit in a pure water-pressure (gas or dissolved gas) mode,

$$\eta = I_{w.r.}\eta_{w.} + I_{d.g.}\eta_{d.g.} + I_{g.c.}\eta_{g.c.}, \quad (49)$$

where: n – oil recovery coefficient of the facility; $n_{w.}$ – oil recovery coefficient when the facility is developed only in water-pressure mode; $n_{d.g.}$ – oil recovery coefficient when the facility is developed only in the dissolved gas mode; $n_{g.c.}$ – oil recovery coefficient when the facility is developed only in the gas cap mode.

The oil recovery coefficients of many deposits in South-Western Turkmenistan, including the NK_3 horizon of the Okarem field, were substantiated using this method. When approving the oil and gas reserves of the Okarem field, due to insufficient information, the oil recovery coefficient of the NK_3 oil and gas horizon was adopted based on general considerations of the equally probable influence of various reservoir energies, without considering the conditions and nature of their manifestation. The characteristic of the development of the NK_3 horizon shows that the deposit in question is drained under a mixed regime. This means that the dissolved gas regime, the water pressure regime and the gas cap regime are simultaneously manifested in different ratios in the formation. Elastic forces act only in the initial period of development and in this case have little effect on the results of the oil recovery process (Guo et al. 2023).

Extrapolation of the displacement indices of the gas cap, dissolved gas and water pressure modes shows that they asymptotically approach 0.2, 0.1, and 0.7, respectively (**Figure 11**). From the studies, the oil recovery coefficients of the water-pressure regime – 0.463, the dissolved gas regime – 0.2 (to determine the oil recovery coefficient in the dissolved gas regime, a graph was constructed using data from the laboratory of underground hydrodynamics of the All-Union Petroleum Research Institute), and the gas cap – 0.25 (**Figure 12**). Under such conditions, the expected oil recovery coefficient of the NK_3 horizon of the Okarem field will be 0.394. Considering the accuracy of the initial data and the accepted calculation methods, the value of the oil recovery coefficient is rounded to 0.4.

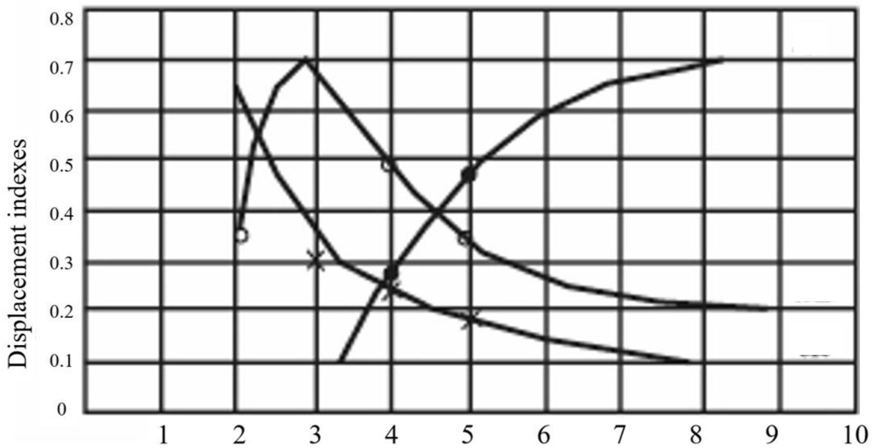

Figure 11—Dynamics of displacement indices of the NK3 horizon of the Okarem field.

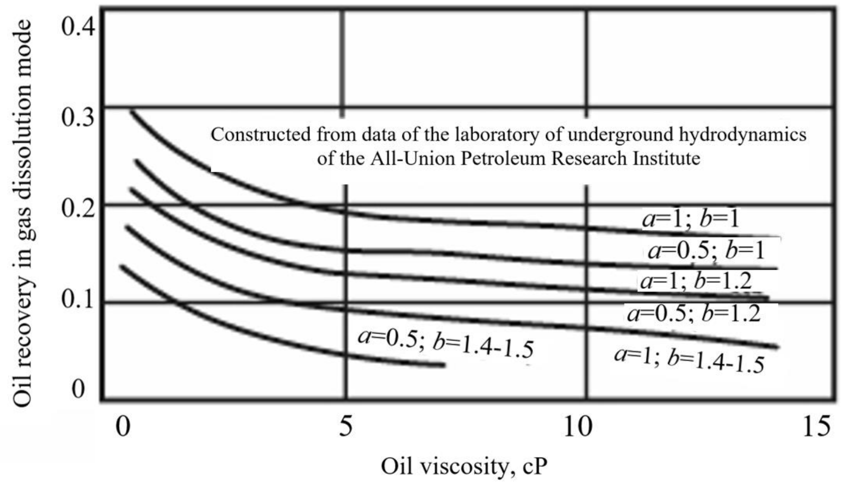

Figure 12—Graph of the dependence of the oil recovery coefficient in the dissolved gas regime on the viscosity and volume coefficient (*b*) of oil and on the solubility coefficient (*γ*).

In cases where the displacement index of the water pressure regime is 0.85 or higher, the gas released from the oil only favourably affects the process of oil movement to the bottom of production wells, without reducing the oil recovery coefficient. Therefore, for such cases, as an oil recovery coefficient of an object, in general, its value for a clean water pressure regime is taken (a number of counting objects of the Goturdepe field).

Summarising the above, it can be concluded that the material balance method, in the presence of reliable initial data, gives good results both in assessing the initial balance reserves of oil and in determining the oil recovery coefficient (recoverable reserves). In addition, this method can be successfully applied in the analysis of the development of an operational facility to determine the proportion of each type of energy involved in oil production.

Discussion

The analysis of the commercial evaluation of oil deposits by the material balance method is a key tool for determining the volume of oil reserves and forecasting their operational efficiency. This method is based on a thorough analysis of data on oil production, production volumes, physicochemical properties of oil reservoirs, and the parameters of wells and production systems.

According to Jing et al. (2021), numerical modelling of the purification of marine heavy oil by hydrocyclones is an important tool for predicting and optimising the purification process of oil products. Hydrocyclones are devices used to separate liquid mixtures into components of different densities by centrifugal forces. In the context of offshore oil production, where heavy oils with a high content of viscous and dense fractions are often found, hydrocyclones can be an effective means for pre-refining oil before further processing. Numerical modelling allows analysing the operation of hydrocyclones considering various parameters, such as the diameter of the hydrocyclone, flow velocity, concentration of heavy fractions in oil. These data are consistent with the theses given in the previous section. The simulation allows optimising the operation parameters to achieve maximum cleaning efficiency with minimal energy and resource consumption. This approach helps to reduce the loss of valuable oil, improve product quality, and reduce the negative impact on the environment by using resources more efficiently when refining oil on offshore platforms or during onshore processing. Oil remains a strategic resource providing the main sectors of the economy, and it is important to consider its effective use. The commercial evaluation of oil deposits using the material balance method plays a key role in this process, allowing not only to determine reserves and production efficiency, but also to predict the further development of the industry and manage resources in a changing energy environment and challenges facing the oil sector.

Referring to the definition of Al-Obaidi (2021), the analysis of hydrodynamic methods for increasing oil recovery is an important area of research in the oil industry, since these methods play a crucial role in increasing the production of hydrocarbons from deposits. Hydrodynamic methods are aimed at changing the physical and chemical parameters of the reservoir and well equipment to increase the permeability of the reservoir, reduce the viscosity of oil, improve its lifting and expand the drainage zone. One of the most common methods is the introduction of water, steam, or chemicals into the reservoir. This may include technologies such as drainage wells, the introduction of polymers, surfactants, or foam generators. Hydrodynamic models allow analysing the impact of such methods on fluid dynamic processes in the reservoir and predict their effectiveness. By analysing various implementation scenarios, it is possible to determine the optimal strategies for specific fields, which allows maximising oil production and reducing production costs. Before analysing the commercial evaluation of oil deposits, the material balance method collects and further analyses data on current oil production from a specific field. These data include parameters such as well flow rates (the volume of oil production over a certain period of time), reservoir pressures, temperatures, oil composition (for example, density, viscosity, impurity content), and other characteristics. Further, these data are used to build a material balance, which is the main tool for evaluating oil reserves at the field. The material balance considers the flow of oil into the system (reserves in the reservoir, resource base, possible replenishment) and the outflow of oil from the system (production). In fact, this is an analysis of material flows in the system, which allows estimating the volume of oil produced, its changes over time, and predicting the dynamics of production.

Huang et al. (2024) determined that the assessment of the productivity of shale gas wells is an important stage in the development and operation of shale deposits. There are several assessment methods that can determine the potential of wells and predict their performance. One of the main methods is the analysis of data from geophysical and geological studies, which allows assessing the properties of rocks, the structure of the formation, and the probability of the presence of gas and oil wells. With the help of seismic data and drilling of test wells, it is possible to identify potential areas for drilling production wells and predict their performance. Another method for evaluating the productivity of shale gas wells is numerical modelling. This approach considers complex physicochemical processes occurring in the formation and well, such as rock fracturing, gas and liquid flows, the influence of hydraulic fracturing technologies, and other parameters. Numerical models help to predict well performance under various operating conditions and plan optimal strategies for shale gas production. This approach helps to improve the efficiency of field development, minimise risks, and optimise production costs. These results confirm the above study, since modern methods of evaluating the productivity of shale gas wells not only increase the accuracy of forecasts, but also provide a deeper understanding of the physical and chemical processes in the formation, which is key to the successful operation of shale deposits. One of the main advantages of the material balance method is its relative simplicity and the ability to obtain an initial estimate of oil reserves based on available data. This method also enables production forecasts to be made and optimal field development strategies to be determined, which is an important aspect of oil company planning.

Saha (2022) has found that the use of remote sensing and geographic information systems (GIS) is becoming increasingly common in hydrocarbon exploration due to its ability to provide a broad and objective overview of territories, and analyse various aspects of the geological structure and composition of the Earth's surface. Remote sensing, based on the analysis of the spectral characteristics of reflected and emitted radiation, allows detecting signs of the presence of hydrocarbons, such as changes in soil characteristics or the presence of characteristic geological formations. It is possible to agree with this opinion that the combined use of remote sensing and GIS helps to comprehensively analyse and visualise spatial data, including information about the geological structure, topography, relief, geochemical indicators, and other factors affecting the distribution of hydrocarbons. This allows not only detecting potential deposits, but also assessing their potential, determining the optimal locations for drilling and development, and predicting the characteristics of hydrocarbon reserves. This approach significantly improves the efficiency of exploration and helps to reduce the cost of searching and developing new hydrocarbon deposits. However, it must be borne in mind that the material balance method has its limitations. It does not always consider changes in the physicochemical properties of reservoir fluids during production, such as changes in the composition of oil or its properties under the influence of production. This may lead to insufficient accuracy of forecasts and estimates of reserves. In addition, when working with complex fields where various types of oil deposits and complex geological structures are present, the material balance method may be less effective due to a simplified approach to modelling production processes.

As noted by Dordzie and Dejam (2021), the effectiveness of various oil production methods has a significant impact on the commercial evaluation of deposits. Various extraction methods, such as the use of artificial uplifts, hydraulic fracturing technologies, thermal extraction methods, drainage and gas lift systems, have their own characteristics and effectiveness in various conditions of the geological and technological environment. The effectiveness of the chosen extraction method directly affects production volumes, production costs, the degree of economic feasibility of field development, and the environment. For example, hydraulic fracturing (or fractionation) technology has become widespread in the production of shale hydrocarbons in recent decades. It allows extracting oil from reservoirs with low permeability, which was previously difficult or impossible. However, this method requires significant investments in technological equipment, preparation and treatment of the formation, and may also raise concerns due to environmental problems associated with it, such as water pollution and seismic activity. Thus, the effectiveness of oil extraction methods must be evaluated considering all aspects to ensure a balance between economic efficiency and environmental sustainability. The combination of the material balance method with other methods of analysis and modelling provides a more complete and reliable picture of oil reserves, production efficiency, and optimal field development strategies. The combined approach considers various factors affecting the oil production process and minimises risks when making decisions in the oil industry.

In general, the analysis of the commercial evaluation of oil deposits by the material balance method is an important tool for the initial assessment of oil reserves and planning their development. However, to obtain more accurate and reliable data, it is often necessary to combine it with other assessment and modelling methods, such as numerical reservoir modelling and hydrodynamic analysis. Hou et al. (2021) determined that the estimated final production of shale oil and gas depends on several key geological factors that determine the opportunities and limitations in the extraction of hydrocarbons from shale formations. One of the main factors is the rock permeability. Shale horizons are often characterised by low permeability due to the microscopic pore size and impermeability to liquid and gas. This creates difficulties when passing hydrocarbons through the porous structure of rocks, which reduces final recovery. Another important factor is the presence and structure of cracks in shale formations. Fracturing of the rock can significantly increase permeability and facilitate the extraction of hydrocarbons. Geological features of the formation, such as the thickness of shale formations, their geomechanical properties, composition, the presence of a gas shell, also have an impact. All these factors determine the conditions of production and its efficiency, and also require a comprehensive analysis and assessment when developing strategies for the extraction of shale hydrocarbons. In addition, factors such as the geographical location of the deposit and its environment must be considered. For example, the availability of infrastructure, the possibility of conducting geological research and production, and potential environmental risks and social aspects are important in the development and implementation of shale hydrocarbon production projects. All these factors together determine the ultimate success of the project and its impact on the economy and the environment. Thus, the analysis and consideration of all these factors are necessary for the development of effective and sustainable strategies for the extraction of shale hydrocarbons.

Conclusions

The analysis of the commercial evaluation of oil deposits by the material balance method is an important tool in the oil and gas industry for determining oil reserves, forecasting production, and developing optimal strategies for exploration and production at fields. The use of this method provides a comprehensive understanding of the condition of the deposit, its geological structure, and operational capabilities.

In the presence of reliable initial data, the material balance method demonstrates high efficiency both in evaluating initial oil reserves and in determining the oil recovery coefficient (recoverable reserves), and it can also be successfully applied to analyse the development of an operational facility to determine the proportion of each type of energy involved in oil production. This method provides an opportunity to estimate the remaining oil reserves in the field using data on current production, reservoir properties, and physical parameters of wells. This is important for planning long-term operation and making strategic decisions. In addition, the analysis of the material balance method allows forecasting oil and gas production based on data on technological processes and production dynamics. This helps to optimise the mining process and manage resources more efficiently. The results of the analysis also help to determine the optimal strategies for field development, including the choice of production methods, investment planning, and optimisation of production processes.

However, the material balance method has its limitations. For example, it is necessary to consider changes in the physicochemical properties of reservoir fluids during the extraction process, which affects the accuracy of forecasts. In addition, this method may be less effective when working with complex fields where various types of oil deposits and complicated geological structures are present. In such cases, additional analysis and modelling methods are required to more accurately evaluate and predict hydrocarbon production. Nevertheless, with the correct interpretation of the data and consideration of all factors, the analysis by the material balance method remains an important tool for the assessment and development of oil fields. One of the constraints of this study is the limited availability of data on the physicochemical properties of reservoir fluids in various fields, which may affect the accuracy of forecasts and estimates when using the material balance method for analysing oil deposits.

For a more complete understanding of the commercial evaluation of oil deposits using the material balance method, additional study of the effect of changes in the physicochemical properties of reservoir fluids on the accuracy of forecasts and methods of adaptation to work with complex deposits is necessary.

Nomenclature

Q_o = Initial oil reserves;
$Q_{o.p.}$ = Oil production accumulated over time;
b_1 = Volume coefficient of oil in a two-phase system, determined from the expression b1=b+(ro-r)o;
bo = Initial volume coefficient of oil;
b = Current volume coefficient of oil;
rp = Average gas factor;
ro = Initial solubility of gas in oil;
r = Current solubility of gas in oil;
υ = Volume coefficient (current) of reservoir gas;

W = Volume of water embedded in the reservoir;
w = Volume of extracted water;
X = Specific elastic capacity of the deposits;
P = Pressure;
$Q_{g.}$ = Gas reserves of the gas cap;
υ_0 = Volume coefficient of the gas at the initial reservoir pressure.

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