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Research of numerical indicators for the development of the Asselskaya area of Orenburg oil and gas condensate field using the material balance method

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The purpose of this work is to analyze and forecast the development indicators of the Assel deposit of Orenburg oil and gas condensate field. To complete this task, a large amount of data is required, which was obtained from the technological development project. The calculation is performed using a program written in the Python programming language. The variables for the material balance equation are given, some of them are calculated using intermediate formulas. The average values of the parameters over the last 15 years of development were chosen as the optimized parameters, since small amounts of cumulative production in the first years of development can lead to a significant error in the calculation of the material balance equation. Also, a comparison was made of the estimated forecast for the development of the Assel deposit with the forecast, according to the state plan, presented in the field development project. The comparison was made on the main parameters: cumulative oil production, annual oil production, oil recovery factor and water cut. For a visual comparison of the calculated parameters, dependency graphs are presented that reflect the forecast made by the material balance method, as well as the forecast based on the data of the state plan. The difference in the behavior of the curves shown on the graphs can be explained by the inaccuracy of the parameters describing the reservoir, as well as the inaccuracy of determining the initial recoverable reserves. This is also affected by the difference in reservoir drawdowns for injection and production wells, proposed in the state plan and in the forecast. Of course, the inaccuracy of the injectivity and productivity coefficients of wells, which were selected based on the estimated volumes of water injection and oil production, also affects. Based on the calculation performed, it can be concluded that it is expedient to further exploit the Asselskaya area of Orenburg oil and gas condensate field with the introduction of a reservoir pressure maintenance system until 2079. According to the forecasts, the water cut equal to 96% will be achieved in 2079, while the oil recovery factor will be 0.427.

Keywords: production analysis, material balance, production and injection forecast, reservation pressure dynamics, displacement characteristics

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1. Introduction

Currently, Orenburg oil and gas condensate field is in the stage of declining oil and gas production, which is due to the extremely intensive rates of fluid withdrawal in the early stages of development. In this regard, the problem of forecasting further production is more relevant than ever. Due to the long history of field operation, we have a large amount of data [1–3], that allows us to adapt the mathematical model to real conditions, as well as to build a forecast for further operation, including using modern methods of maintaining reservoir pressure [4–6].

The purpose of this work is to analyze and forecast the development indicators of the Assel deposit of Orenburg oil and gas condensate field. To complete this task, a large amount of data is required, it was obtained from the Technological Development Project [1]. The calculation is performed using a program written in the Python programming language [7]. The variables for the material balance equation are given in Table 1, some of them are calculated using intermediate formulas.

2. The material balance method and numerical results

The coefficient m, which is the ratio of the volumes of gas and oil in the reservoir, was found as the quotient of the initial oil and gas grades multiplied by the average oil and gas saturation coefficients.

The coefficients S_{wio} and S_{wig} are found as the difference between unity and the average coefficient of initial oil and gas saturations, respectively.

First of all, to create a material balance model, it is necessary to calculate the coefficients that depend on pressure, such coefficients are: Bo, Bg, Bw, Rso.

After calculating the model coefficients, the remaining coefficients Bt, $Bgc = Bg$, Bw, Btw.

The values of the coefficients Bo_i, Bg_i, Bw_i, Rso_i, respectively, are the knowledge of the coefficients Bo, Bg, Bw, Rso for the zero year of operation (the letter "i" means initial conditions).

Having calculated all the necessary coefficients for

Table 1. Limits of adaptable parameters

Adaptable Parameter	Border (Multiplier)	
	Lower limit (in. units)	Upper limit (in units)
Reservoir pressure (Pr)	0.99	1.01
Initial recoverable reserves (N_{calc})	0.9	1.2
Reservoir compressibility factor (cf)	0.001	100
The ratio of the volume of gas to the volume of oil in the reservoir (m)	0.5	1.1

each of the years of operation of the field (1984–2011), we can make the final equation of the material balance, solved with respect to the N numbers of initial reserves. Thus, when comparing the obtained values of the equation and the actual values of N given in the development project, we can verify the correctness of our reservoir model.

In order to run the model, the program needs input data that includes years of production, reservoir pressure, and oil, associated gas, and water production. A table is compiled in Excel from these values and connected to the material balance model [8].

Having received a table for the initial reserves N, we can observe the deviation from the indicators presented in the Technological Development Design. These deviations can be explained by the inaccuracy in determining the coefficients m, cf, as well as inaccurate measurements of reservoir pressures. To solve this problem and correctly adapt the model, the following method is proposed.

We obtained in [9] the values of the above parameters, which allow us to minimize the error, thereby adapting the model under consideration to real conditions. The following limits of adaptable parameters were used in the work (Table 1).

To minimize the material balance error, the optimize.minimize function of the SciPy library was used, using the L-BFGS-B method (The BFGS-B method, an iterative numerical optimization method, is named after its researchers: Broyden, Fletcher, Goldfarb, Shanno. It is the so-called quasi-Newtonian method. Unlike Newtonian methods, the quasi-Newtonian methods do not directly calculate the Hessian of the function, i.e. there is no need to find second-order partial derivatives. So, the Hessian is calculated approximately from the steps taken so far), because this method allows you to optimize the function in the presence of boundary conditions for the adapted parameters.

As a result of optimization the following values of the considered parameters were obtained (Table 2).

The dependence of recoverable reserves on the year of operation as well as the graph of the decline in calculated and actual reservoir pressures are shown in Fig. 1 and Fig. 2, respectively.

The average values of the parameters over the last 15 years of development were chosen as the optimized parameters, since small amounts of cumulative production in the first years of development can lead to a significant error in the calculation of the material balance equation.

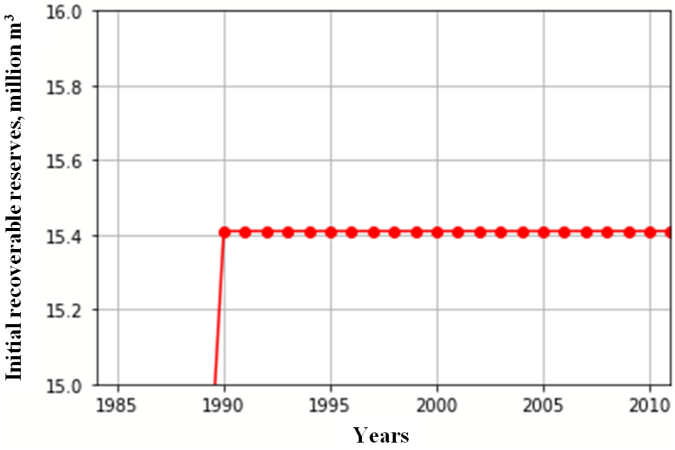

Figure 1. Dependence of recoverable reserves on the year of operation

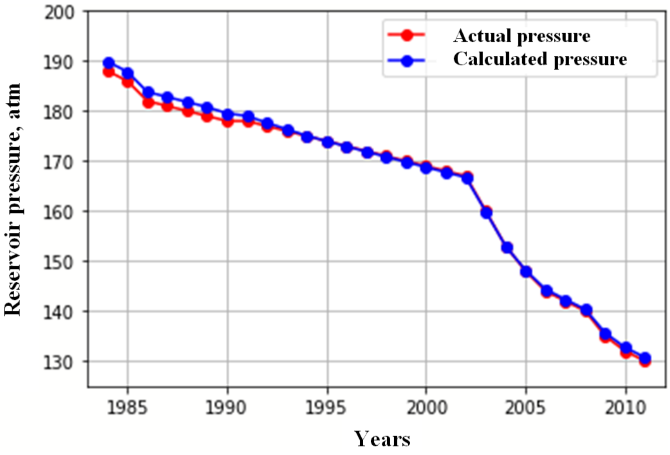

Figure 2. Graph of the drop in calculated and actual reservoir pressures

Based on the foregoing, the material balance model can be considered tuned, since it describes the development history and the formation fluid displacement mechanism with satisfactory accuracy. The next stage of the calculation part of the work is the forecasting of the field development.

For a more correct and accurate development forecast, it is necessary to set parameters that would fully reflect the process of fluid displacement from the reservoir. To do this, it is necessary to calculate the oil recovery factor from the reservoir. By comparing the calculated and actual coefficients, we will be able to adjust the mathematical model of

Table 2. A result of optimization of the parameters

Reservoir pressure (atm)	Initial recoverable reserves (million m^3)	Compressibility factor (1/atm), $\times 10^5$	The ratio of the volume of gas to the volume of oil in the reservoir (units)
189.8	13.9	0.5	0.143526
187.8	13.9	0.5	0.143526
183.8	13.9	0.5	0.143526
182.8	13.9	0.5	0.143526
181.	13.9	0.5	0.143526
180.7	14.4	0.5	0.143526
179.5	15.4	0.434	0.163165
178.9	15.4	1.399732	0.206502
177.6	15.4	2.549454	0.233183
176.3	15.4	4.020333	0.258903
175.1	15.4	4.791520	0.281062
173.9	15.4	14.68	0.287615
172.9	15.4	27.2	0.288339
171.9	15.4	38.94	0.289020
170.9	15.4	50.9	0.289716
169.8	15.4	60.95	0.290296
168.8	15.	71.54	0.290910
167.7	15.4	80.1	0.291406
166.7	15.4	87.64	0.291844
159.9	15.4	46.92	0.289477
152.9	15.4	13.52	0.287545
148.2	15.4	4.43	0.270583
144.4	15.4	3.76	0.251325
142.3	15.4	3.85	0.254087
140.3	15.4	3.79	0.252464
135.6	15.4	2.67	0.220127
132.7	15.4	2.24	0.208423
130.7	15.4	2.15	0.205257

the reservoir to the historical development data [10, 11].

To calculate the recovery factor, it is necessary to know the characteristics of oil displacement by water. An extremely important parameter in the construction of displacement characteristics is the relative phase permeability. To find it, a calculation was performed based on the data presented in the development project [1] (Table 3).

We obtained the best approximation of the model curves to the experimental data obtained by the Corey power model [9] (Fig. 3).

Having got the values of the relative phase permeabilities, we find the values of the Buckley-Leverett function, as well as the theoretical oil recovery factor.

Now let's find the actual oil recovery factor using field production data. Comparing the actual and theoretical oil recovery factor, we find an unsatisfactory convergence of the results. In order to optimize the actual and theoretical oil recovery factors, we will adapt the parameters nw and no to the watering history. As a result, we get the following plot of water cut versus oil recovery factor (ORF) (Fig. 4). The convergence of the results is satisfactory.

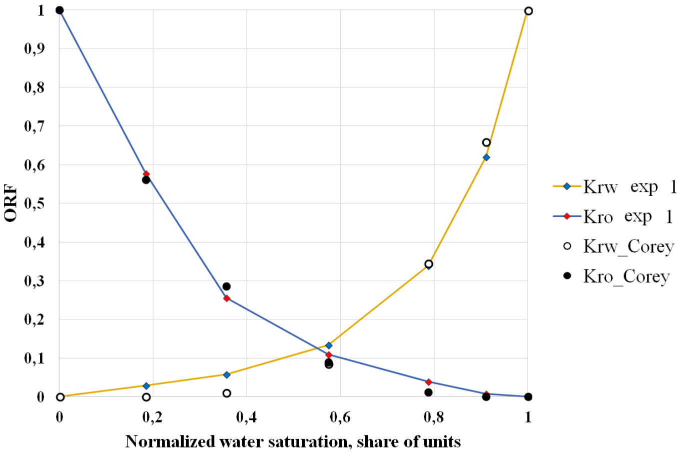

Figure 3. Relative phase permeability curves

The calculation of the field development forecast will be carried out based on the first (basic) forecasting option presented in the technological development project. This option provides for the drilling of 10 additional production

Table 3. Relative phase permeabilities for oil and water

Pore space water saturation, *Sw*	Relative phase permeability for water, *Kw*	Relative phase permeability for oil, *Koil*
0.178	0.000	1.000
0.26	0.008	0.577
0.337	0.016	0.256
0.434	0.037	0.11
0.529	0.094	0.039
0.584	0.172	0.008
0.624	0.277	0.000

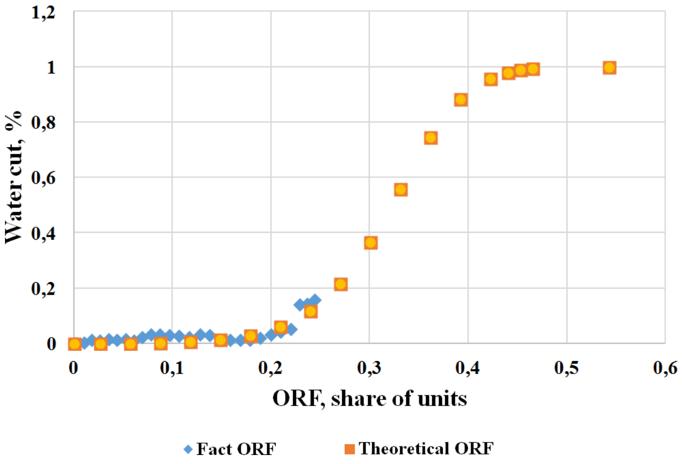

Figure 4. Graph of dependence of water cut on oil recovery factor

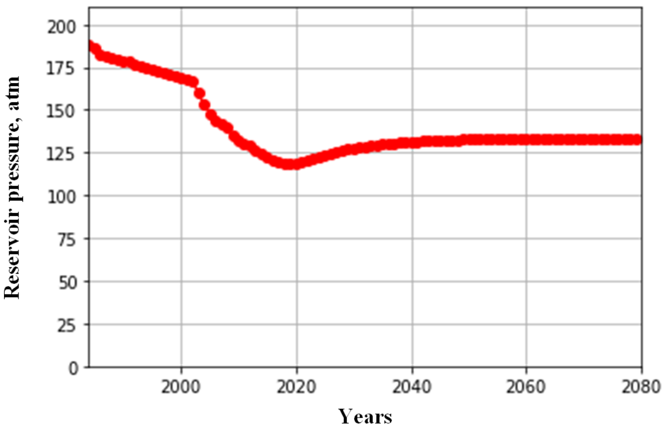

Figure 5. Reservoir values

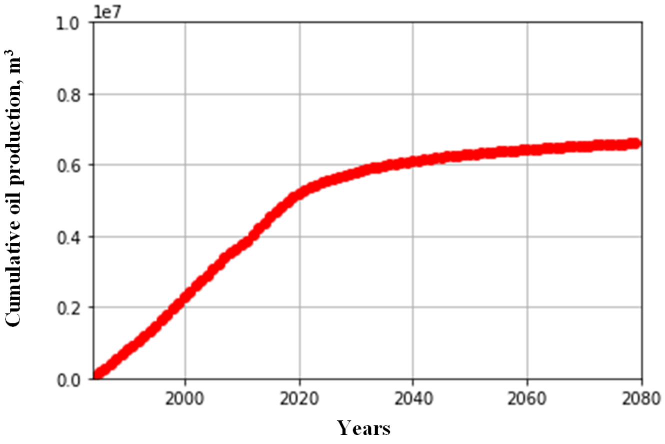

Figure 6. Cumulative oil production values

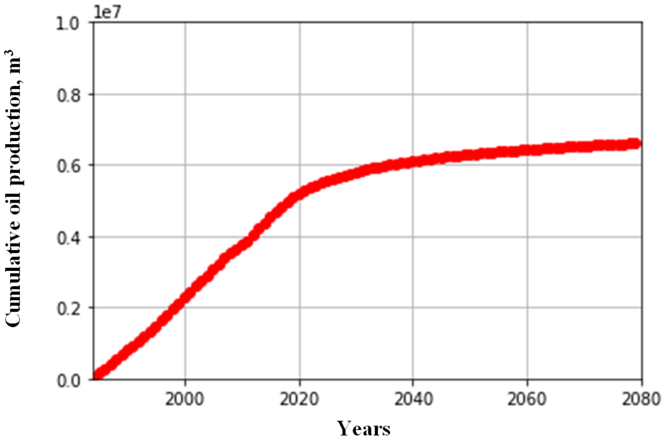

Figure 7. Values of annual oil production

wells, as well as the transfer of 15 previously producing wells for injection, the maximum oil production is 160 thousand tons, the volume of water injection ranges from 21 to 388 thousand m^3 per year, the average daily injection is from 56 to 1063 m^3, the average injectivity of wells varies from 28 to 91 m^3 per day. The forecast is carried out until the production water cut reaches 98%.

Calculation of relative permeability for oil and water was carried out based on the adapted parameters *no* and *nw* for the development history.

The number of production and injection wells corresponds to the first development option. Productivity and injectivity coefficients are accepted as corresponding to the dynamics of annual withdrawals and fluid injection.

Since wells are operated using the periodic gas lift method, for predictive calculations, a constant fluid flow rate was taken as a boundary condition for production wells, and a constant bottom hole pressure for injection wells.

The values of reservoir pressures, cumulative oil production, and annual oil production are presented in Fig. 5–7 respectively.

Also, a comparison was made of the estimated forecast for the development of the Assel deposit with the forecast, according to the state plan, presented in the field development project. The comparison was made on the main parameters: cumulative oil production, annual oil production, oil recovery factor and water cut.

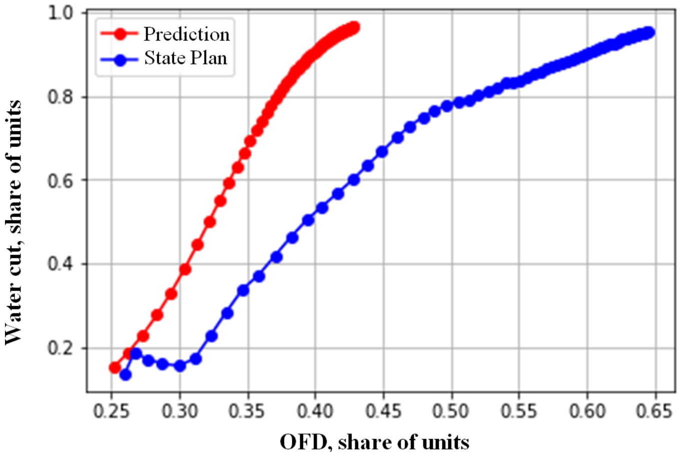

Figure 8. Water cut

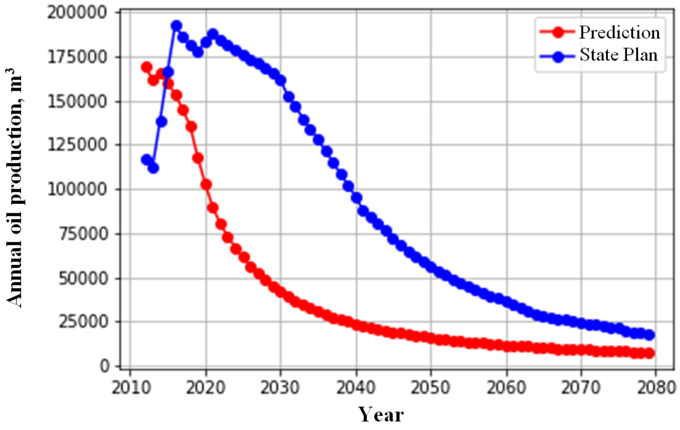

Figure 9. Annual oil production

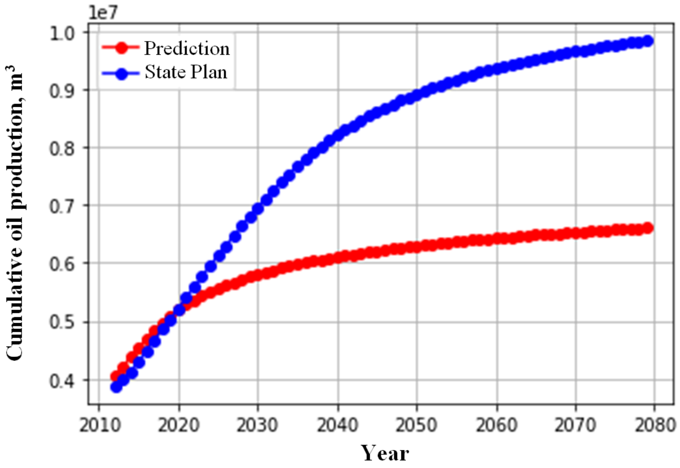

Figure 10. Cumulative oil production

For a visual comparison of the calculated parameters, we will present dependence graphs that reflect the forecast made by the material balance method, as well as the forecast based on data from the state plan (Fig. 8–10).

The difference in the behavior of the curves depicted in the graphs can be explained by the inaccuracy of the parameters describing the reservoir, such as cf, m, as well as the inaccuracy of determining the initial recoverable reserves. This is also influenced by the difference in drawdown for the reservoir for injection and production wells, proposed in the state plan and in the forecast. Of course, the inaccuracy of the injectivity and productivity coefficients of wells, which were selected based on the estimated volumes of water injection and oil production, respectively, also has an impact.

It should be noted that the development forecast made in accordance with the state plan takes into account additional oil reserves below the oil-water contact and above the gas-water contact, which are not listed on the state balance sheet. In the author's calculation, performed by the material balance method, when adapting the model from 1984 to 2011, additional reserves are not confirmed. For this reason, the recovery factor achieved in the calculation (0.428 with a water cut of 96.6%) corresponds to the design recovery factor equal to 0.439, in contrast to the recovery factor according to the state plan (0.645).

3. Conclusions

Based on the calculation performed, it can be concluded that it is expedient to further exploit the Asselskaya area of Orenburg oil and gas condensate field with the introduction of a reservoir pressure maintenance system until 2079.

According to the forecasts, the water cut equal to 96% will be achieved in 2079, while the oil recovery factor will be 0.427.

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