Integral analysis of geological and field data for selection of oilfield development strategy

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Abstract. The reservoir development plan is a complex process and should be analysed from different points of view. The process was analysed in terms of geology, petrophysics, modelling, production technology and economics. Therefore, different methods should be used for the project.

1. Introduction
The oilfield A is located in Kaymysovky oil region next to Dvurechenskoe and Krapivenskoe oilfields. There are 9 exploration wells drilled in field A, five of which have core data. The base properties, such as porosity, permeability and water saturation are determined on the basis of core data. As the main material the following logs data are used: gamma ray log (GR), spontaneous potential log (SP), resistivity logs, neutron logs, potential logs, and so on. There were 270 samples taken from core of different production intervals. All data were analyzed separately for two production intervals: $U_1^{1\text{-}2}$ and $U_1^{3\text{-}4}$. The properties distribution was constructed on the basis of core data.

2. Analysis of geological and field data
First of all, the intervals, which could be potential sources of hydrocarbons, were determined on the basis of SP and GR logs for all wells [1]. The shaliness should be calculated for the effective porosity analysis. Shale normally contains radioactive bearing minerals and gamma ray log could be used for shale identification. Shaliness was analyzed using different models, the best result was achieved by the Larionov model. On the basis of this method the effective porosity curve was calculated for each well. The comparison of core porosity and log porosity for $U_1^{1\text{-}2}$ and $U_1^{3\text{-}4}$ was made separately. Then on the basis of the «base well» concept, the effective porosity curves were built for wells without core data. The «base well» was determined using the following criteria: wells lithology similarity and the lateral distance between the wells (well A2 was chosen).

The permeability was measured with the use of nitrogen gas, so the core permeability data were corrected on the Klinkinberg effect, provided that there was a slippage effect of gas molecules along the grain surface. Then the dependency between porosity and permeability was calculated based on core data. The effective porosity curves were used for this reason. It was decided to use unique dependency for each development object. Despite the fact that the exponential type of correlation was obtained, the determination coefficient was high, due to log and core porosity similarity. The average log derived parameters for $U_1^{1\text{-}2}$: φ=15%, k=7.7 mD, S_w=0.48; for $U_1^{3\text{-}4}$: φ=17.2%, k=176 mD,

S_w=0.43. The average core derived parameters for U_1^{1-2}: φ=13.2%, k=8.8 mD, S_w=0.56; for U_1^{3-4}: φ=18%, k=162 mD, S_w=0.37.

One of the main objectives of property estimation is correct calculation of Stock Tank Oil Initially in Place (STOIIP). However, additional step should be made in order to eliminate the values which are of minor importance for reservoir field development. The criteria for this elimination include several steps: water saturation, porosity, permeability and shaliness cut-off criteria [2]. The cut-off criteria are estimated separately for each productive formation. The cut-off criteria are defined for U_1^{1-2}: S_w=0.76, φ=0.116, k=0.88 mD, V_{sh}=0.24 and for U_1^{3-4}: S_w=0.73, φ=0.1202, k=1.06 mD, V_{sh}=0.27.

The interpreted parameters such as porosity, lithology logs and well picks of formation boundaries were used as an input data. The structures of geological model were constructed by offsetting Bazhen bottom structure.

The next step was to build up of 3D structural grid. Using modeling software, separate grids were constructed for U_1^{1-2} and U_1^{3-4}. Geological model was build using cell size of 100 m by 100 m for U_1^{3-4} and U_1^{1-2}. The size was chosen to optimize calculating time and obtain accurate model. The number of layers were selected so that the model fully describes vertical heterogeneity typical for regional depositional environment. The STOIIP (Stock Tank Oil Initially In Place) was U_1^{3-4}=7.92 mln m^3 and U_1^{3-4}=34.81 mln m^3.

The lithological characteristics were distributed by means of indicator modeling. In terms of lateral trends variogram from similar rocks was used and vertical lithology was distributed by vertical proportional curves for each layer separately [3]. Variogram parameters for lateral distribution were: azimuth – assumed direction of sediment deposition, long section rank – 4000 m, cross-section rank – 2000 m. Vertical variogram parameters: 1 m for U_1^{1-2} and up to 3 m for U_1^{3-4}. In terms of input data the pointwise interpretation of porosity log was used and then it was scaled into cells. Then the porosity parameter was distributed by kriging interpolation method. The same azimuth of variogram was used for lithology distribution.

The estimation of hydrocarbons volume is based on statistic data correlation results of petrophysics and core analysis [4]. The STOIIP estimation is conducted by three primary methods: deterministic, stochastic or probabilistic, and geo modeling [5]. Using the deterministic method, the STOIIP for U_1^{1-2} is 7.49*10^6 m^3 and for the U_1^{3-4} is 33.9*10^6 m^3. Using the stochastic method, the STOIIP for U_1^{1-2} is 7.6*10^6 m^3 and for the U_1^{3-4} is 34.2*10^6 m^3. Using the geological model, the STOIIP estimation is 7.92*10^6 m^3 and 34.81*10^6 m^3, respectively.

The simulation model was based on geological model [6]. Upscaling process was implemented to reduce the number of cells and optimize calculating timing. The lateral dimension of a cell remained unchanged; however, vertical cell thickness was scaled up from 0.8 m to 2 m. The reservoir properties were scaled up to a coarser cell. The STOIIP of geological and simulation model were 42.73 mln m^3 and 41.39 mln m^3, respectively, for both layers. The dynamic processes were defined by single relative permeability result provided with the core data [7].

The simulation model was produced by Tempest «Roxar» software. Static parameters, such as geological model porosity, permeability, and saturation were used as initial parameters and also PVT properties (Pressure, Volume, Temperature) were used being approximated by specific correlations [8].

Economic analysis of the project was based on evaluation of several potential scenarios of field development. The main variation parameters were drilling pattern and distances between wells, rate of fluid extraction and water injection, changing pattern orientation, hydraulic fracturing, horizontal wells, separate and unified development of both production intervals [9]. All these scenarios were evaluated by the economic model and the most profitable scenario was 5-point pattern with 500*500 in low permeability-thickness product (kh) zones and 1000*1000 in high kh zones.

The choice of formation pressure maintenance was defined by type of formation, the size of the formation and its oil-bearing zone, the presence of gas cap, formation oil viscosity, type of reservoir rock and its permeability, the level of formation heterogeneity, the presence of tectonic failure, and others. The presence of two objects of development with similar properties resulted in evaluating two distinct variants of development: joint and separate.

Two zones of different kh values were defined during reservoir properties evaluation. The kh varies from 1000 to 5000 mD*m at north-west block, whereas at the south-east block the kh values are less than 1000 mD*m.

The largest oil recovery index of 51.1% was demonstrated by 5-spot with the 500 meter spacing between production and injection wells. However, comparing economic interpretations, it was shown that, according to kh maps, the most efficient approach was to develop two production zones separately: 500*500 m between production and injection wells within zones of low kh and less concentrated pattern of 1000*1000 m in zones of higher kh values. The case was considered to be the most economically viable with recovery factor 50.6%, which was less than previously mentioned pattern (with recovery factor 51.1%) by 0.5%.

Also, the variant with natural depletion mechanism was simulated. Initially, the case had shown recovery factor 2%, whereas after simulation modeling it revealed recovery factor 9%, which indicated that the aquifer was not included in calculations. As one of the potential pattern of development, horizontal well pattern was simulated. The main challenge in this case was to justify the bottomhole pressure on production wells [10].

It is assumed that the construction is started in 2015 and it is to be continued to first quarter of 2018 when the production commences. The estimate economic life of the field is 8 years with a payback occurring between year 3 and 4. The total production of oil recovered during the project life is 21.2 mln tons of oil and 712.1 mln m^3 of gas (used for power generation). The economic oil recovery index (0.45) achieves in 8 years and technical oil recovery index (0.50) achieves in 25 years.

Depreciation of assets was performed using Declining Balance method with 25% rate. There were additional funds accounted for miscellaneous (5% from total Capital Expenditures (CAPEX), excluding drilling cost) and for environmental reclamation (5% from total CAPEX). Also, to account for uncertainties, the contingency fund of 25% from total CAPEX was established. There was some exploration cost included in Well development section of capital expenditure.

The revenue will be generated from sales of oil. Contained gas volumes are not in sufficient marketable quantities. Taxation represents 78%, a significant portion of total expenses on the project. Tax model consists of various federal and regional, labor taxes and royalties.

Sensitivity analysis was carried out on the following parameters by changing one parameter at a time between ±30% at 10% intervals while maintaining the rest of the following parameters constant. The Net Present Value (NPV) of field A is the most sensitive to the taxes and exchange rate and less sensitive to Operating Expenditures (OPEX). The Internal Rate of Return (IRR) period of project was the most sensitive to taxes and CAPEX and, secondly, to oil price and less sensitive to OPEX.

The project will produce marketable Urals brand oil which will be sold to local transfer oil pipeline located 30 km from field A. The oil will be treated and analyzed on site before releasing for sale.

3. Conclusions

As a result of the study the development model was constructed and the final variant was chosen. The best variant has no technological limits and the NPV is much higher than in other variants.

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