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: U₁¹-² and U₁³-⁴. 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 U₁¹-² and U₁³-⁴ 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 U₁¹-²: φ=15%, k=7.7 mD, S₆=0.48; for U₁³-⁴: φ=17.2%, k=176 mD,
were scaled up to a coarser cell. The STOIIP of geological and simulation model were 42.73 mln m³.

The reservoir properties reduce the number of cells and optimize calculating timing. The lateral dimension of a cell remained 7.92*10^6 m.

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 U1^1-2 is 7.49*10^6 m³ and for the U1^3-4 is 33.9*10^6 m³. Using the stochastic method, the STOIIP for U1^1-2 is 7.6*10^6 m³ and for the U1^3-4 is 34.2*10^6 m³. Using the geological model, the STOIIP estimation is 7.92*10^6 m³ and 34.81*10^6 m³, 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 m³ and 41.39 mln m³, respectively, for both layers.

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 m³ 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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