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DEVELOPMENT ENGINEERING PRACTICE OF A FIELD WITH A SALINE RESERVOIR IN EASTERN SIBERIA. PART 2

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ОПЫТ ПРОЕКТИРОВАНИЯ РАЗРАБОТКИ МЕСТОРОЖДЕНИЯ ВОСТОЧНОЙ СИБИРИ С ЗАСОЛОНЕННЫМ КОЛЛЕКТОРОМ. ЧАСТЬ 2

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Engineering practice of a field complicated by high level of uncertainty in geological structure, abnormal properties and composition of formation water, and presence of halite in pore space of the reservoir is described. Maintaining reservoir pressure is fundamental for ensuring target production levels, yet its implementation is not always a trivial task. The problem of a saline reservoir simulation has been studied on an East Siberian field with reservoir's high heterogeneity, low permeability, and salination. Practice of determining the optimal system of development using modern methods of simulation, analysis and calculation is considered. Multivariate calculations were conducted using a hydrodynamic model based on the probabilistic geological model. The methodology of selecting the basic variants of the geological model corresponding to the probability of 10, 50, and 90 % was used subject to two factors: initial geological reserves and reservoir connectivity. Qualitative and quantitative estimations of changes in production wells productivity due to problems caused by organic and inorganic sedimentation in the bottomhole formation zone were performed. Formation water and mineral composition of the rock formation were analysed. These data were used to simulate the organic and inorganic sedimentation in the bottomhole formation zone due to changes in pressure and temperature during production and fluid injection into the formation. The simulation of solids build-up during fluid flow in the bottomhole formation zone allowed us to determine threshold values of well producing characteristics and bottomhole pressure levels, as well as dependencies of decrease in reservoir properties of the bottomhole formation zone on the amount of pumped fluid under the selected well operation parameters.

Ключевые слова:
разработка месторождений, ТРИЗ, засолоненный коллектор, неорганические осадки, моделирование рассоления, расчет продуктивности скважин.

Приведен опыт проектирования месторождения, осложненного высоким уровнем неопределенности по геологическому строению, аномальными свойствами и составом пластовой воды, наличием галита в поровом пространстве коллектора. Поддержание пластового давления – одно из обязательных условий обеспечения планируемых уровней добычи, однако его реализация не всегда тривиальная задача. На месторождении Восточной Сибири с высокой неоднородностью коллектора, низкой проницаемостью и засолонением исследована проблема моделирования засолоненного коллектора. Рассмотрен опыт определения оптимальной системы разработки с использованием современных методов моделирования, анализа и расчетов. Были выполнены многовариативные расчеты с помощью гидродинамической модели, за основу которой взята вероятностная геологическая модель. Использована методика выбора основных вариантов геологической модели, соответствующей вероятности 10; 50 и 90 % с учетом двух факторов: начальных геологических запасов и связности коллектора. Проведена качественная и количественная оценка изменения продуктивности добывающих скважин вследствие осложнений, вызванных выпадением органических и неорганических осадков в призабойной зоне пласта. Выполнен анализ пластовой воды и минералогического состава горной породы. Эти данные были использованы при моделировании образования органических и неорганических отложений в призабойной зоне пласта вследствие изменения термобарических условий при добыче и закачке жидкости в пласт. Моделирование образования твердой фазы при фильтрации жидкости в призабойной зоне пласта позволило выявить пороговые значения эксплуатационных характеристик скважины и уровней забойного давления, а также зависимости ухудшения фильтрационно-емкостных свойств призабойной зоны пласта от количества прокаченной жидкости при выбранном режиме работы скважины.

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Introduction

The field under study is complicated by a high level of uncertainty in geological structure [1–3], abnormal properties and composition of formation water, and the presence of halite [4] in pore space of the reservoir.

Due to a combination of geological and physical properties (type of reservoir, low porosity and permeability, high compartmentalisation of formations), the hydrocarbon reserves of productive formations are hard to recover. The field is mainly characterised by:

– high reservoir compartmentalisation, block structure;

– low reservoir properties;

– low reservoir temperature;

– reservoir salination; and

– high formation water mineralisation.

The main productive area includes terrigenous deposits with average porosity values of 10 %, permeability from 1 mD to 1 D, average value of 150 mD, net oil thicknesses of 8–10 m, on average. Due to the massive character of the deposit, significant net gas pay zones, under-gas-cap zones, net oil pay zones, and underlying water zones can be distinguished.

Flow Model Building

Numerical simulation model allows one to calculate the consequences of a certain engineering solution to a production problem using a computing experiment method. Creation of a live hydrodynamic model was aimed at addressing the problems of the optimal scenario of field development [5], including:

– study of the fluid flow processes in productive formations;

– determination of optimal parameters of the development system;

– study of possibilities to enhance the formation development;

– determination of optimal development scenario; and

– forecast of probable production volumes.

Oil reserves in the field are classified as hard-to-recover, due to low permeability and high geological heterogeneity. This makes it necessary to artificially maintain formation pressure during reservoir operation from the very beginning of its development [6, 7]. When water is injected into a reservoir, especially with low permeability, the oil displacement process is mostly affected by pore space structure, rock wettability, and swelling of clay minerals. Distinctive features of the reservoir under study include its salinity [8–10], as well as high mineralisation (400 g/l) and high viscosity (4 cPz) of the formation water.

The overlying low-mineralised water is currently the agent of reservoir maintenance [11], which, when injected into the reservoir, will react with formation water, reducing its mineralisation, and also react with salt crystals, changing the pore space geometry. For the purpose of selecting the technology and agent of the formation pressure maintenance (FPM), a number of laboratory studies have been conducted using core samples and field fluids [12, 13]. The laboratory studies have revealed that at injection of the flooding agent there is a significant change in the structure of the pore space, i.e. an increase in porosity, permeability, and connectivity of pore channels, etc. [10].

In multiphase numerical simulation models, the functions of relative permeabilities of a phase (RPF) play a significant role [14]. These functions are empirical and are determined in a laboratory environment on core samples, or analytically, using generalized dependencies. There are a number of factors affecting the RPF functions, including structural characteristic of the porous medium, wettability, direction of saturation variation, etc. However, the scope of laboratory research using core samples cannot be compared with that of the field, which is why the RPF functions and capillary pressures can be modified in the course of the model adaptation to the actual development data, as may be required.

RPF was modified [12] in order to allow for the influence of pore space salination at fresh water injection. The laboratory studies on desalination were reconstructed and the desalination model coefficients were obtained. Building a full-scale model with the chemical option of desalination is more time-consuming and is not suitable for probabilistic calculations. To accelerate the calculations, the model was adapted using modified functions of relative permeability of a phase (MRPF) with regard to desalination. The results are presented in Fig. 1. As can be noted, a significant change in the water RPF curve is associated with an increase in permeability after desalination. It should be stated that the MRPF curves also allow for the change in formation water viscosity at the displacement front when fresh water is injected.

At the construction stage, geologic models were created that describe the existing reservoir uncertainties, from which it was necessary to choose three representative implementations to be used in the future. To address this problem, the calculations were performed applying GeoScreeening module which allows using streamlines to identify the most valid models with a probability of 10, 50 and 90 % (hereinafter referred to as p_{10}–p_{50}–p_{90}) by reserves and subject to interconnected pore volume. Based on the calculation (Fig. 2), selected were the models that described three scenario cases: best-case, base-case and worst-case (p_{10}–p_{50}–p_{90}, respectively).

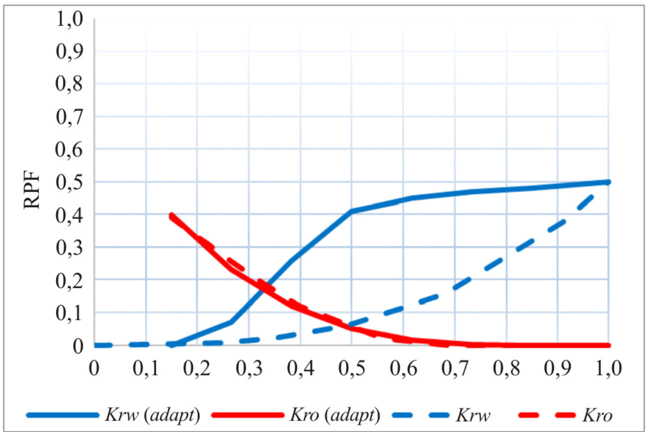

Fig. 1. Comparison of RPF values obtained from the laboratory core sample studies and MRPF values: *Krw* and *Kro* are dependencies of relative permeability of a phase for water and oil, respectively (based on the core sample study) on the saturation of porous medium with water phase; *Krw* (*adapt*) and *Kro* (*adapt*) are modified dependencies of relative permeability of a phase for water and oil, respectively (based on the hydrodynamic model adaptation) on the saturation of porous medium with water phase

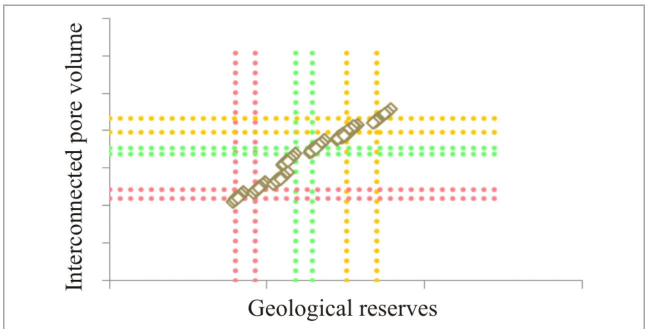

Fig. 2. Multi-parameter selection of three main scenarios of the geological model

The models differed in structure, distribution of flow properties (FP) and reservoir, and were limited by a significant spread in gas-oil and water-oil contact values. As a result, the difference in reserves between the worst-case and best-case scenario models is up to two times.

Substantiation of Well Profiles

A number of laboratory and computational studies were conducted to adjust for the risks of changes in production and injection wells performance in the process of field development.

Stage 1: collection and processing of information from laboratory studies [15] aimed at determining geological and physical characteristics of the reservoir:

– porosity, permeability and flow properties of the rock formation;

– mineralogical composition of the rock;

– mineralogical composition of formation water;

– component composition of oil;

– physical properties of formation fluids under reservoir conditions; and

– petrophysical dependencies.

Further, the results of special flow studies aimed at FPM agent selection were collected. The dependencies of permeability change on the amount of pumped pore volumes of water for various mineralisation and initial permeability were obtained in the course of laboratory studies, wherein it was accepted that the share of halite in the rock is proportional to its permeability. These dependencies were taken into account in multivariate calculations to select an effective FPM system.

Stage 2: qualitative analysis of permeability impairment risks in the bottomhole formation zone (BFZ) due to man-induced impact during production well operation. In addition to BFZ damage, occurring during a range of well operations (drilling, killing, hydraulic fracturing, well workover, etc.), there are risks of BFZ's flow properties impairment in the course of production and injection well operation [16–22]. The principal risk for production wells is organic and inorganic sedimentation, especially considering the abnormal mineralogical composition of rock and formation water, and pressure and temperature conditions of the deposit.

For qualitative and quantitative prediction of organic sedimentation from oil (asphaltene-resin-paraffin deposits (ARPD)) at the change of pressure and temperature conditions (simulation of the process of oil inflow to the well bottom), the initial data must be determined: pressure and temperature conditions, component composition of oil, molar mass of components, mass fraction of paraffins and asphaltenes in the oil composition, and molar mass of oil. Most of the data was obtained through laboratory tests of bottom-hole oil samples. Yet, to calculate the amount of settled asphaltenes, a more detailed component composition is necessary, rather than the one that is usually determined in standard studies. In the current situation, it was decided to use a component composition extension model. For this purpose, the C7+ fraction can be broken down into more components [22]. Next, the formation oil phase equilibrium under given pressure and temperature conditions was calculated based on the equation of state of the multi-component hydrocarbon system [23–32]. As a result, the dependencies of the settled ARPD volume ratio on temperature and pressure of the system were obtained (Fig. 3). Thus, it was established that at bottomhole pressure above 9 MPa, there is a minimal risk of ARPD sedimentation in BFZ. A large number of coefficients, taken by analogy, correlation method or from publications, were used in the course of calculations. An extended program of laboratory experiments to confirm the model applied is scheduled for the future.

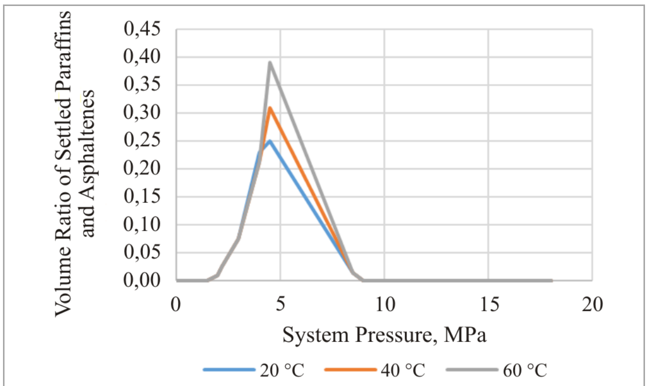

Fig. 3. Dependency of settled ARPD volume ratio on formation pressure

The model allowing for water phase flow and changes in the mass of rock and salt sedimentation was used [33, 34] for direct calculation of the probability of organic deposition and associated processes that affect flow properties. The qualitative model determines what happens to the salt component under current pressure and temperature conditions (depending on the thermodynamic resolution coefficient) [35]. The quantitative model is represented by a system of equations that was solved numerically using a difference scheme, where the first equation is the mass-conservation equation for salt, the second equation is the continuity equation for oil, the third equation is the continuity equation for water, and the fourth equation is the mass-conservation equation for rock (matrix).

$$\begin{cases} \dfrac{\partial \varepsilon \omega S \rho_w}{\partial t} + \operatorname{div} \rho_w \omega V_w = -\rho_{salt} \dfrac{\partial (1-\varepsilon)}{\partial t}, \\ \dfrac{\partial \varepsilon (1-s)}{\partial t} + \operatorname{div} V_{oil} = 0, \\ \dfrac{\partial \varepsilon S (1-\omega) \rho_w}{\partial t} + \operatorname{div} \rho_w (1-\omega) V_w = 0, \\ \rho_{salt} \dfrac{\partial (1-\varepsilon)}{\partial t} = -\rho_w \alpha S (\omega_{eq} - \omega) \omega, \end{cases}$$

where ε is porosity, unit fractions; ω is dimensionless concentration of salt in water, unit fractions; S is water saturation, unit fractions; α is mass-transfer coefficient, 1/s; ρ_w, ρ_{salt} are densities of water and salt, respectively, kg/m^3; and V_w, V_{oil} are flow rates of water and oil, respectively, m/s.

As a result, permeability profiles and share of salts settled in BFZ under the change of pressure and temperature conditions due to inflow to production well were obtained (Fig. 4). Anhydrite and a small share of calcite are the prevailing salts, formed in the BFZ according to all known data on the reservoir.

Distribution of the sediments and permeability ratio was calculated for different time periods, different flow properties and different modes of well operation (bottomhole pressure value and draw-down). The results were processed to obtain coefficients to the skin factor dependency on time using the Chirkov-Mikhailov's method [36]. The coefficients and dependencies were used in the hydrodynamic calculations.

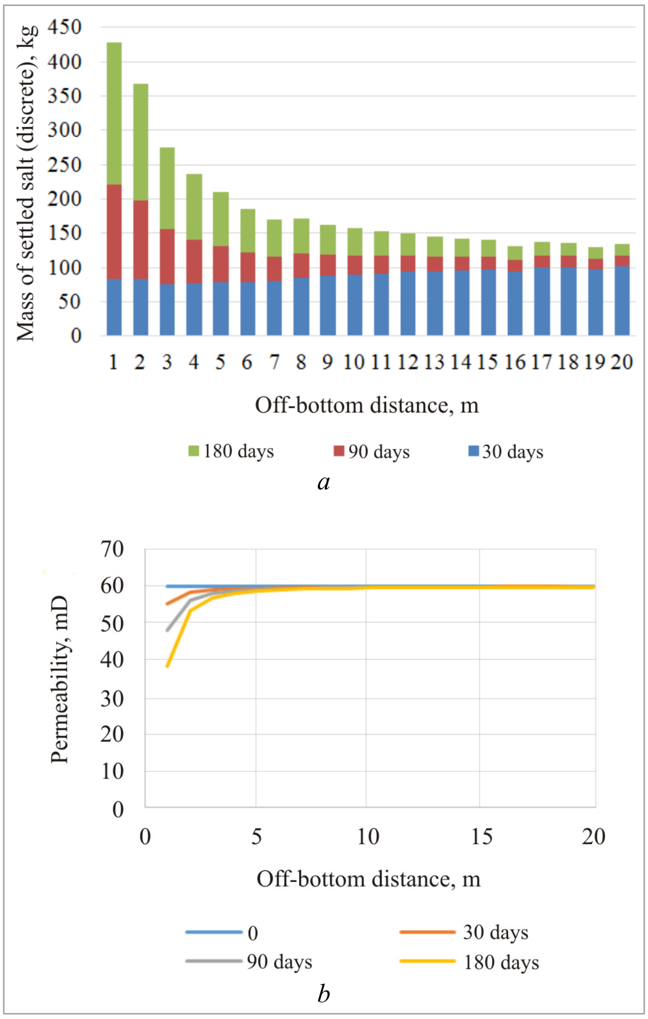

Fig. 4. Simulation of changes in flow properties of the production well BFZ during operation: distribution of inorganic sediment mass (*a*) and permeability (*b*) in BFZ by results of various time intervals simulation

Determination of Well Spacing Pattern

The selection of effective development systems and optimal well-spacing pattern, which provide cost-effective development, is based on both the practice of similar field development and the results of two- and three-dimensional mathematical simulation of the development process of the reservoir under study.

Authors of a number of researches have proved [37–40] that at a complex geology, in the conditions of heterogeneity of low- and medium-permeability reservoirs, the greatest productivity and high technical and economic performance are achieved through the use of dispersed injection system.

Nowadays, gas and oil reservoir development systems with horizontal wells (HW), which allow enhancing the development of hard-to-recover oil reserves where oil occurs between gas and water, are becoming more common [41–43]. In general, the accumulated field experience of HW operation implies that the horizontal well system is the most efficient and rational technology of field development for the conditions of reservoirs pertaining to the group under study. Yet, since horizontal wells can not provide a sufficient level of sweep efficiency per se due to the heterogeneity and discontinuity of the reservoir (Fig. 5), it was decided to use additional hydraulic fracturing (HF). Since the net oil pay zone is the priority area for development, the HF enables entering all stringers, thereby enhancing reserves recovery.

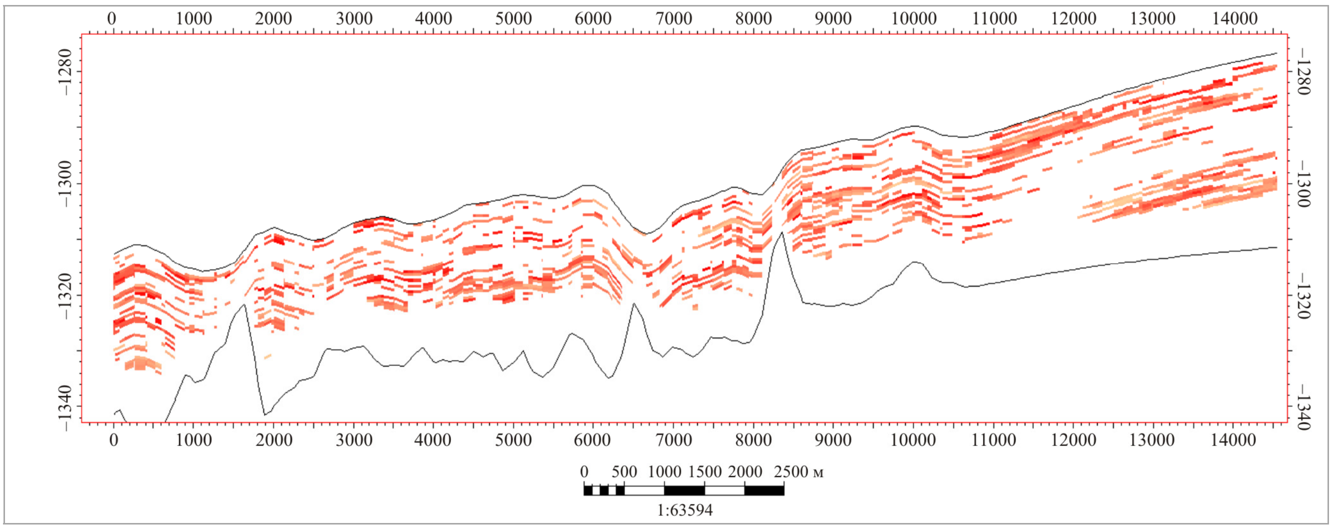

Fig. 5. East-to-west section of the geological model for the target reservoir

The selection of the optimal development system was conducted subject to the following conditions: exploration maturity of the reservoir geology, formations' flow properties, physical and chemical characteristics of formation fluids, reservoir and well drive, the existing development system, the results of development analysis, the degree of depletion and the structure of remaining oil reserves, development background of deposits with similar characteristics, application of working agents for the implementation of the engineered system, maximum sweep efficiency, and effective drainage.

Since the geological structure and properties of the deposit productive formations are so far under-researched for commercial development of oil reserves, at this stage, a preliminary selection of the optimal reservoir development system is performed using a probabilistic geological model that includes several implementations.

For the previously selected implementations of the geological model p_{10}–p_{50}–p_{90}, the actual operation of existing wells was adapted to confirm their validity and the possibility of historical data recovery, prior to hydrodynamic calculations. The variants (p_{10}–p_{50}–p_{90}) with different well spacing patterns were calculated with the adapted models (Fig. 6). The main parameters used to enhance the development system were narrowed down to enumeration of the indicators presented in the Table [44].

Comparison of indicators consisted in obtaining the cumulative production, but since this indicator does not always represent an economic and technological optimum, a simplified economic model was applied to adjust for the net present value (NPV) from the project implementation [45, 46] (Fig. 7).

Variable Parameters of the Optimal Development System Selection Model

Parameter	Variant			
Well pattern	5-spot	Line-drive	–	–
Well pattern azimuth	Along stress trajectory	Across stress trajectory	–	–
Well pattern area (WPA), ha/well	96	125	164	196
HW length, m	1200	1400	1600	
Number of HF	10	12	14	
Flowback period of injection wells, months	1	2	4	6

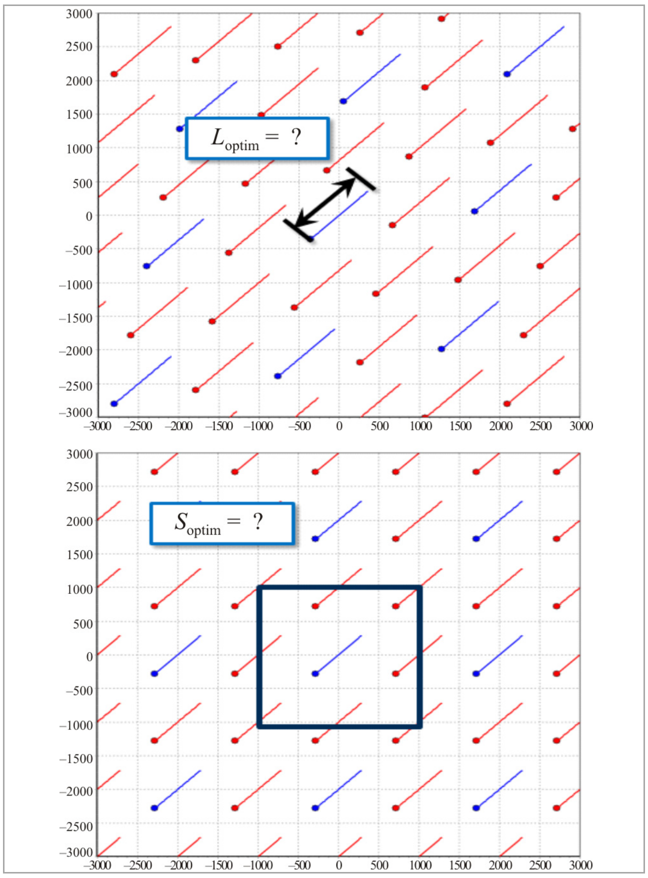

Fig. 6. Determination of the optimal length of horizontal wellbore section and the well pattern: L_{optim} is optimal length of horizontal wellbore section entering the reservoir; S_{optim} is optimal area per one well in the well pattern

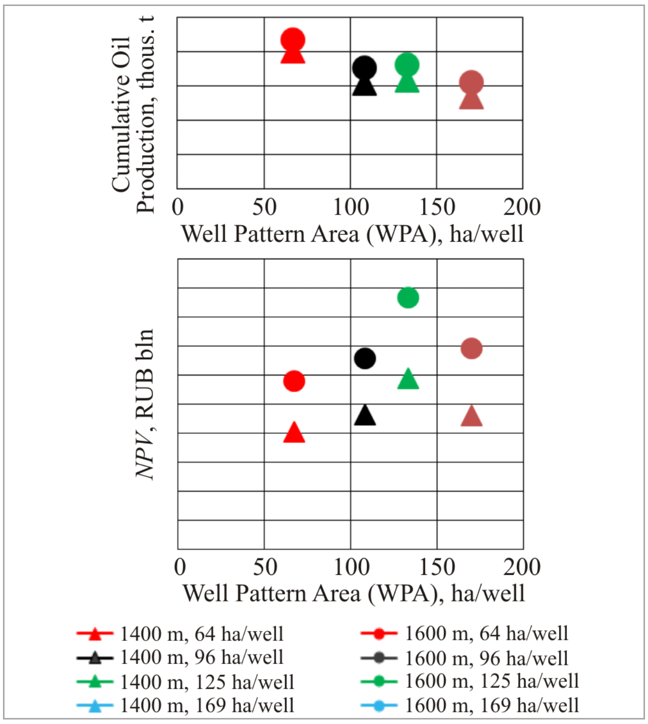

Fig. 7. Comparison of cumulative net production and NPV for well pattern variants with 1,400- and 1,600 m-long wells

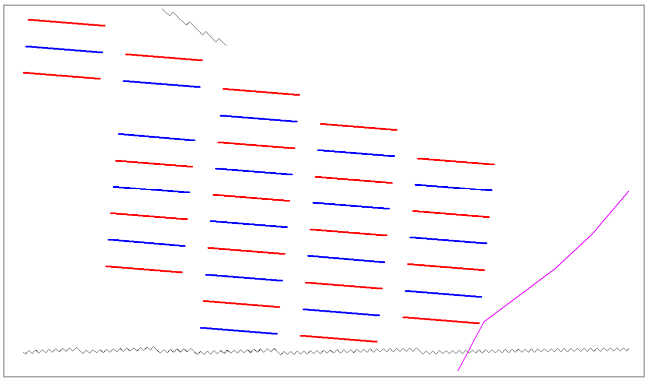

Fig. 8. Final variant of optimal well pattern

Graphical representation of the final system is given in Fig. 8: offset line drive pattern; horizontal wellbore length of 1,200 m with 14 stages of HF, row spacing of 500 m, and well spacing of 450 m. The selected type of development system is relevant only for the pilot section of the deposit without a gas cap and underlying aquifers.

Conclusion

Besides the presence of halite in the pore space of the oil-saturated reservoir, the field under study is complicated by a number of other factors, from geology to abnormal properties of formation water. Following the conducted research and its consolidation involving comprehension of all the complicating factors, the laboratory and computational experiments aimed at finding an effective and economically-viable approach to the field development were carried out. Based on the information obtained in the course of laboratory research that involved geological and hydrodynamic simulation, probability calculations were performed, allowing for uncertainties at the current stage of the reservoir study. Geological and well exploitation risks were taken into account, and multivariate hydrodynamic calculations were performed. The most stable development system for the pilot area of the deposit was selected using the economic model.

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