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Evaluation of Artificial Stimulation Methods in the West Absheron Field Based on Hydrodynamic Model

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ABSTRACT

The application of modern approaches to the selection of stimulation methods in fields in the initial stage of development is one of the serious factors affecting the efficiency of the process. Stimulation methods to maintain the development rate and enhanced oil recovery were simulated based on the three-dimensional geological and hydrodynamic models of the productive horizons of the Western Absheron field, and the issues of efficiency evaluation of these methods were considered. On the basis of geological-geophysical-mining data, geological and hydrodynamic models of the field were established, initial geological resources were evaluated, and the development history was restored in the hydrodynamic model. Selection of more efficient stimulation method was investigated on the basis of the hydrodynamic model, the processes of water, polymer solution, hot water and steam injection into the formations were simulated, the optimal placement of new production and injection wells was defined, the field performance were predicted and compared according to various options. Based on a comprehensive analysis of geological, geophysical, and field data, we have developed detailed geological and hydrodynamic models of the West Absheron field. This has enabled us to estimate the initial geological reserves and to restore the development history in the hydrodynamic model. Based on the results of similar studies conducted at similar fields, the dependencies of phase permeabilities of gas-oil and water-oil ratios were developed for the productive horizons of West Absheron field and corrected in the process of restoring the development history. Using the hydrodynamic model, we studied the issue of choosing the optimal formation stimulation method. We predicted development parameters in six different options and compared the results.

Keywords: Field; Layer; Well; Development; Model; Stimulation Technique; Prediction.

INTRODUCTION

Currently, in accordance with international standards, the field reserves estimation, substantiating and determination of the drilling trajectories of new production and injection wells, development plans and projects of hydrocarbon reservoirs, the implementation of various geological and process works, the feasibility studies of the given processes are performed based on the hydrodynamic model. Since exploration works in new fields, well drilling in producing fields, various stimulation methods, drawing up development projects, etc. require a large amount of financial resources, the model is an important tool in predicting the results at any stage of the process.[1,2,3,4,5,6,7,8,9]

The main objective of reservoir modeling with a comprehensive and accurate study is to determine its condition in advance and explore ways to increase the final oil recovery factor. It is not excluded that the selection of efficient stimulation methods and the study of the factors affecting the process efficiency are performed through the model.[10,11,12,13,14,15,16,17,18]

Research Object

The article is devoted to the simulation of the development process of the Western Absheron field; selection of stimulation method for the full utilization of the residual resources of the field and efficiency evaluation issues are considered, the results are compared, and the field performance is predicted by applying different stimulation methods.

Development of the Western Absheron field started in 1989. The field is dissolved gas drive. The main productive horizons are the Girmaky (QD) and Girmaky Alti (QA) suites. The analysis of actual process parameters, the current oil recovery factor and the prediction of the final oil recovery factor prove the necessity of selection and application of stimulation methods to maintain the field development rate and increase the oil recovery factor. The mentioned task is carried out on the basis of field geological and hydrodynamic simulation.

Geological Model

Field database was created for the development process simulation at first. İt included coordinates, altitude, inclinometry, digital log diagrams, oil, gas and water production data for each well, information on measured initial and current reservoir pressures, reservoir temperature, physical and chemical, thermodynamical properties of reservoir fluids and other research results. Generally, the results of various laboratory studies conducted on the basis of formation fluids and core samples of the Western Absheron field were systematized, digitized and adapted to appropriate formats and uploaded to the Open Works database.

Determination of reservoir parameters is one of the most important factors in field modeling. For geomodelling, determination of such parameters as the depths of the top and bottom of the horizon, the depth of the water-oil contact, the effective thickness and oil-gas capacity, the porosity coefficient, permeability, sand content, clay content, oil-gas saturation is necessary. The main information source is the results of core sample analysis and interpretation of logging diagrams.

Core samples were taken from 10 wells in the course of exploration and drilling operations in the Western Absheron field, and dependencies were established based on the statistics of their physical properties. Based on the results of this analysis and dependencies, the formation parameters were determined through the entire depth for all wells.

Correlation of the results of the core samples analyzes with the results of the geophysical research conducted in the wells and their interpretation made possible estimation porosity, clay, carbonation, and permeability limits in the field and separation reservoir and non- reservoir rocks.

Specific resistance (SR), well potential (WP), neutron log and gamma ray log (GR) data were used as main objects in the petrophysical interpretation. Clay content (V_{Shale}) on the logs was identified first in defining the formation parameters.

The porosity coefficient values were continuously determined throughout the depth by means of the dependances derived from the ration of the porosity value (at the depth corresponding to the core sample values) and the values derived from the clay log.

The value of permeability was determined after definition the values of the porosity coefficient. The permeability-porosity curve established as a result of laboratory studies of core samples taken from wells was used fort his purpose (figure 1). By processing this dependence, an equation reflecting the dependence of permeability on porosity was built for productive horizons, and permeability values were calculated by this equation.

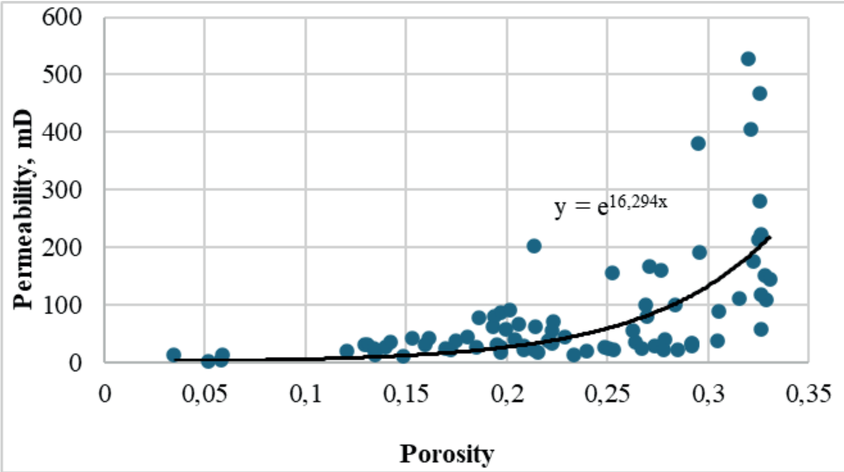

Figure 1. Permeability - porosity curve in the West Absheron field

Change in saturation in the wells was determined with the definition of the values of porosity coefficient. Water saturation value was determined by Archie's method, based on the value of the porosity coefficient, the specific electrical resistance of the formation and formation fluid.

The average values of formation parameters for the horizons of the Western Absheron field are given in table 1.

Table 1. Average values of formation parameters obtained from log interpretation

Horizon	Sandiness, v.h.	Porosity factor, v.h.	Permeability, mD	Water saturation, v.h.
QD1	0,30	0,21	61,0	0,35
QD2	0,33	0,21	66,0	0,35
QD3	0,38	0,21	74,0	0,35
QA	0,35	0,20	79,0	0,34

Note: in calculating the formation parameters, their limit (boundary) values were taken as 11 % for the porosity coefficient (Poro), 50 % for the clay content (Vshale), and 50 % for the water saturation (Sw)

Since permeability (Perm) is related to porosity (Poro), i.e. defined from the Poro curve, the boundary (limit) value of permeability is defined by the boundary value of porosity.

For geological model, compile of two-dimensional maps, and three-dimensional geological models of the reservoir based on these maps provides more accurate results and assists accuracy control of the results. For this, the logging diagrams of all the wells drilled in the formation were correlated, and depth of the top and the bottom of the horizons were specified. Correlation scheme of longitudinal-section as an example is described in figure 2.

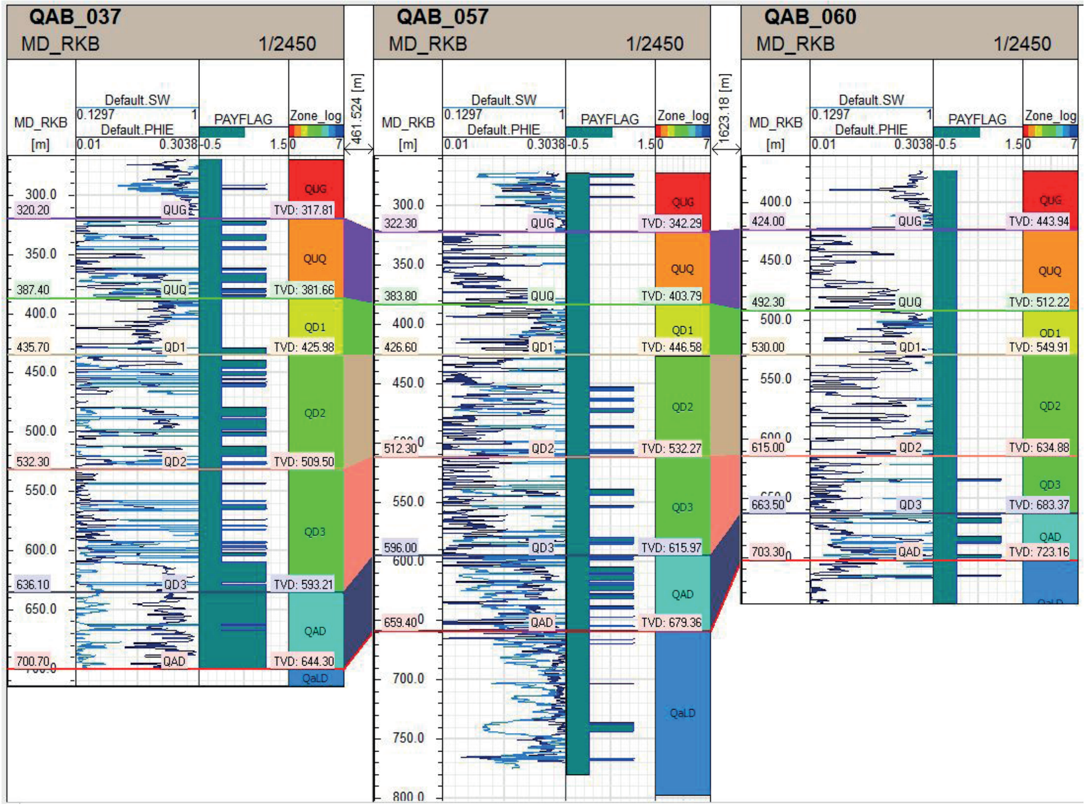

Figure 2. Well correlation schemes

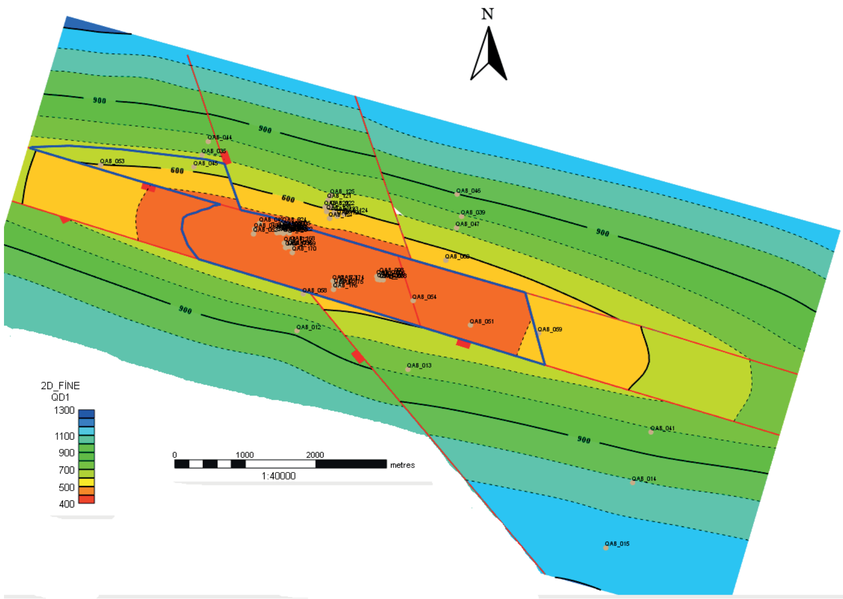

Figure 3. Structural map according to top of the horizon QD1

Despite the fact that the West Absheron field has been in operation since 1985, fundamental seismic exploration work has not been carried out here. For this reason, occurrence mode, depths and faults of the formations have been studied on the basis of logging diagrams. Two-dimensional structural maps of horizons and formations were built on the basis of well correction schemes, top-bottom depths of horizons and absolute values of these depths. Since the main resources in the Western Absheron field are concentrated in QD and QA suite, the QD suite was divided into 3 parts (horizons) (QD1, QD2 və QD3) to make it easier to study the field more accurately and develop the compiled 3D model by programs. As an example, Figure 3 shows a structural map according to the top of the QD1 horizon.

The construction of a three-dimensional geological model is started with structural modeling. Firstly, the frame of the structure was built. During the construction of the structural frame, the tectonic deformations identified according to the well data were three-dimensionally simulated (figure 4). The profile view of horizons in lateral section and their cutting by fractures are also shown in the picture.

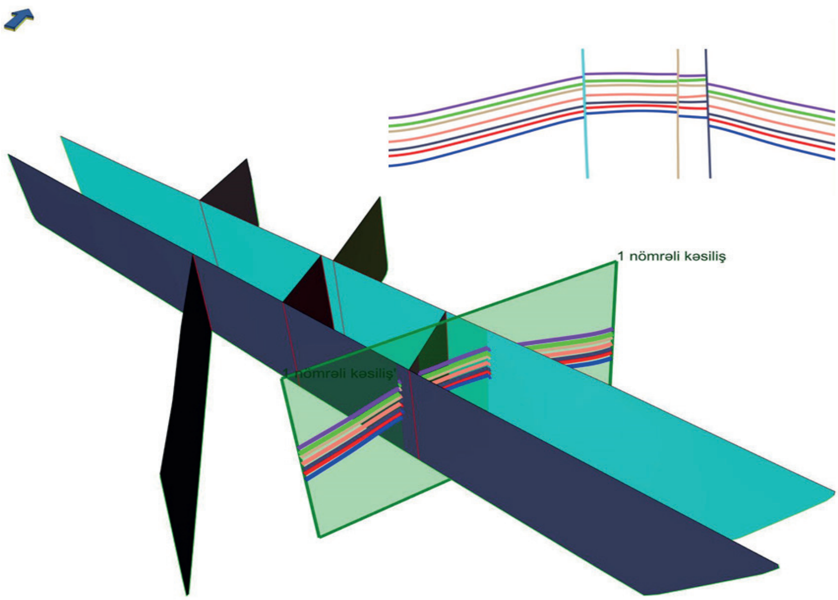

Figure 4. Three-dimensional fracture model

According to the data obtained as a result of interpretations carried out in the drilled exploratory wells, 2 parallel fractures were discovered along the arch in the longitudinal direction of the field. The amplitudes of these fractures change between 50-300 m.

In addition to the longitudinal fractures in the North-West-South-East direction, 5 more fractures have been identified that cross section the field. The amplitudes of these fractures change between 25-100 m. İt is highly likely that the transverse fractures are a continuation of each other.

After the fractures, the surfaces were three-dimensionally simulated according to the top of the QUG, QUQ, QD and QAD Suite of the Western Absheron field (figure 5).

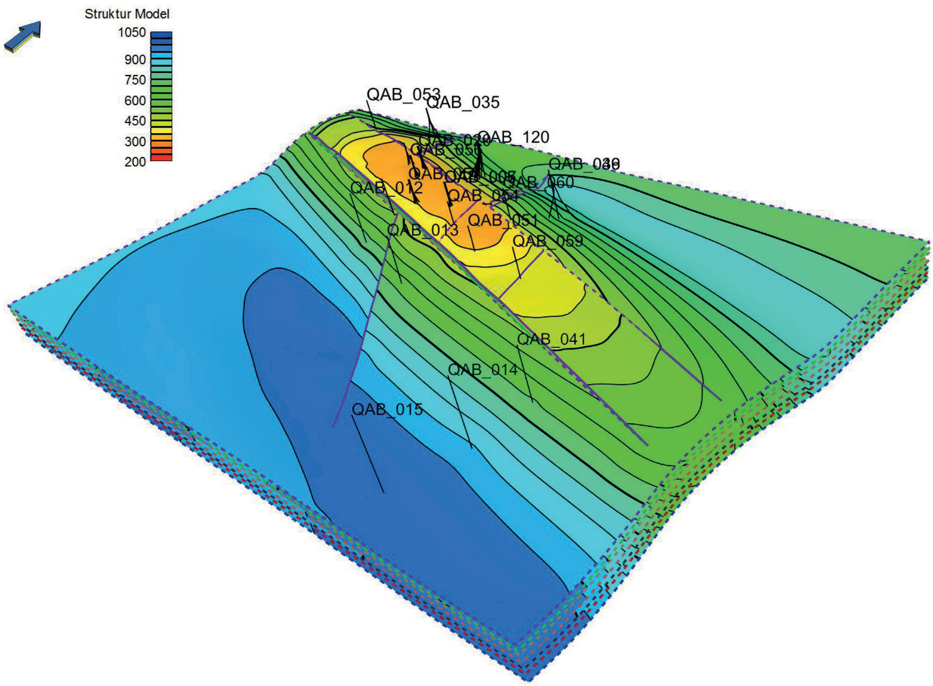

Figure 5. Structural model of the Western Absheron field

After the three-dimensional frame of the horizons is ready, in order to increase the accuracy of the geomodelling, layer parameter distribution, and reserve calculation processes, the horizons are divided into total 1804275 small cells, longitudinal -99 along the X axis, transverse - 45 along the Y axis, and depth-405 along the Z axis , a geological grid was established.

It should be noted that the dimensions of the geological grid are taken as 50x50m along the XY axes. Information about the established geological grid is shown in table 2.

Table 2. Information about the dimensions of the geological grid

Horizon	geological grid (50m×50m)			Number of grid
	X	Y	Z	
QÜG	99	45	60	267 300
QÜQ	99	45	1	4 455
QD1	99	45	90	400 950
QD2	99	45	60	267 300
QD3	99	45	100	445 500
QAD	99	45	94	418 770
Cami	99	45	405	1 804 275

After the geological grid of the field was established, a facies model was built.The distribution of two facies (sand, clay) was carried out on the basis of the conceptual model adopted in the litho-facies modeling of the zones.Then, the distribution of petrophysical parameters (porosity, permeability, water saturation) on selected litho-facies was carried out.

A stochastic distribution algorithm was selected for facies distribution by analyzing the depositional conditions and interpreted well logs in the formation of production horizons of the Western Absheron field.For this purpose "Kriking" method was used in "Indicators" module of "Irap RMS" modeling program. One of the main advantages of using this module is the reconciliation of distribution results with well data and user-specified parameters.

To make the stochastic distribution more deterministic, the results of variogram analysis, 2D sand thickness distribution trend maps prepared on the basis of the accepted concept on horizons, and 1D vertical proportion curves trends obtained from the vertical distribution of facies on the horizon obtained from the interpreted well data analysis were used. In general, variogram analyzes were used to determine vertical and horizontal uncertainty at each stage of constructing parameter models. Averaging the results of experimental variograms with theoretical dependences is used as an input parameter during modeling.

Variogram analyzes were used to each parametric modeling.With the help of variogram analysis, the interval of changes in the heterogeneity of formations on vertical and horizontal sections was determined

Various variogram analyzes were performed for the distribution of facies, and finally, an exponential curve was chosen, and in the facies model, the azimuth was 350, 1000 m in the direction parallel to the azimuth, 1000 m in the normal direction, and 2 m in the vertical direction.

Various variogram analyzes were carried out for the distribution of facies, and finally, 350° azimuth, 1000 m in parallel to the azimuth, 1000 m in the normal direction, and 2 m in the vertical direction was taken by slecting an exponential curve in the fascial model.

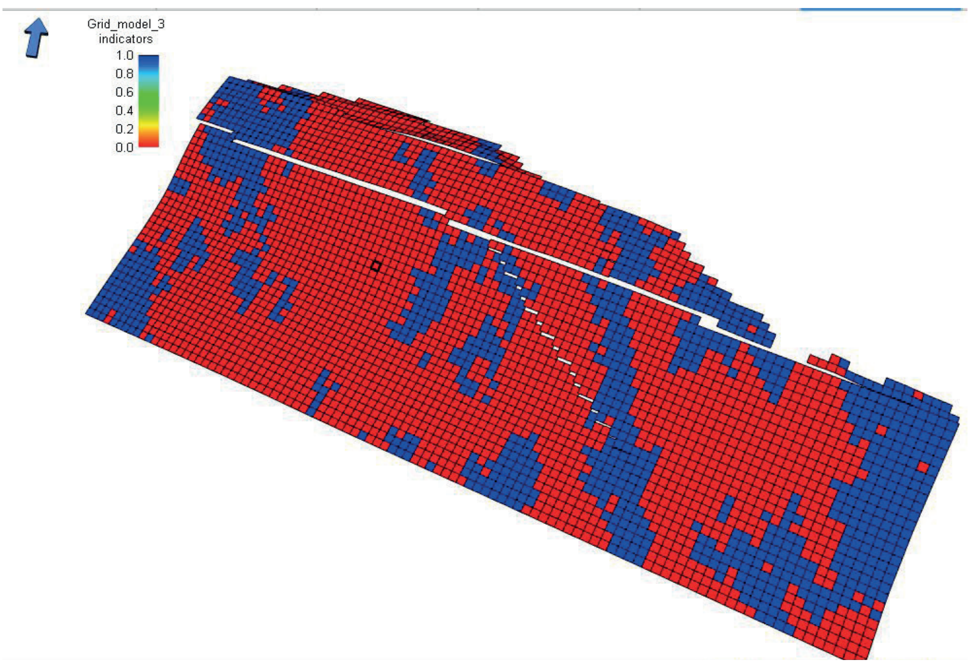

Figure 6. 3D fasial model

The lithologic-facies model of the Western Absheron field was built based on all the well data, the results of the core sample studies, the interpretation of the geophysical research methods of the wells and the general analysis of the results obtained from these studies

A lithologic and facies model of the Western Absheron field was built on the basis of all the well data, test report of drill sample, the interpretation of the geophysical exploration techniques of wells and the general analysis of the results obtained from these studies.In other words, the regularity of distribution of sand-clay facies on the deposit by depth and area has been determined.

The facies model of the Western Absheron field is shown in figure 6.

In the following steps, a petrophysical model (Cube) was built. Porosity, permeability and water saturation parameters were simulated in petrophysical modeling.

A 3D porosity (Phie) model was built with a stochastic distribution by cricking simulation of the effective porosity value after performing multiple analyzes on well data. Different variogram models were tested, and finally, azimuth 350°, parallel 1000 m, normal 1000 m, vertical 1 m distribution variogram with an exponential curve was used (figure 7).

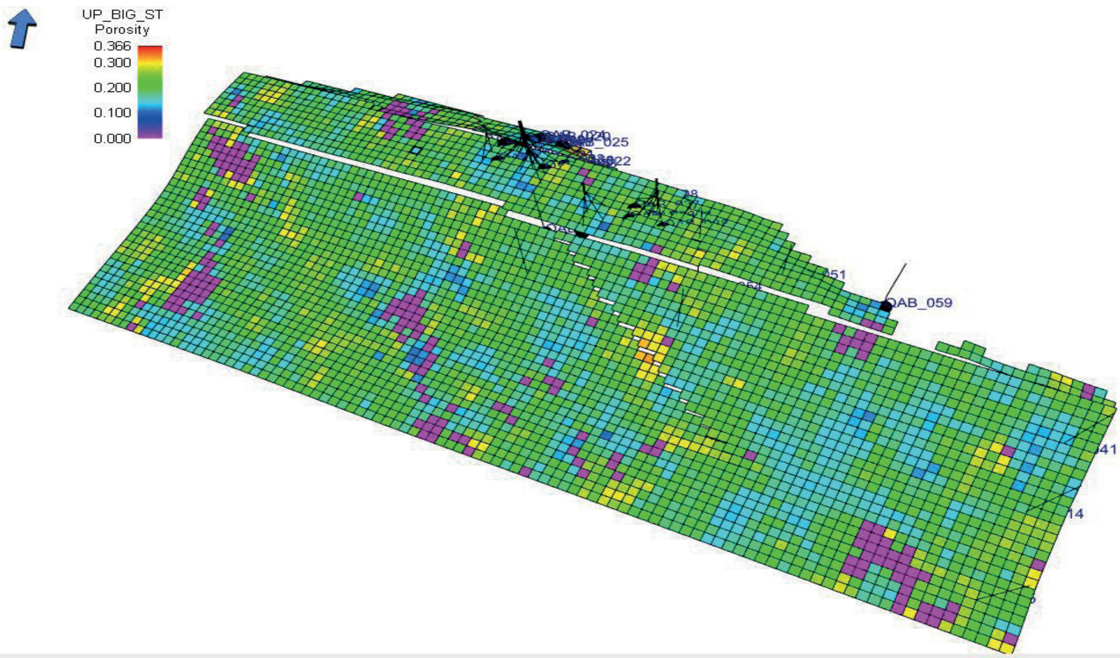

Figure 7. 3D Porosity model

The permeability parameter (Perm) is constructed by a function obtained from both the petrophysical distribution and the porosity dependence. Since the obtained results are similar, finally, it was considered appropriate to establish by the function $K=3,5227 * e^{11,121 \cdot m}$ obtained from the porosity (figure 8).

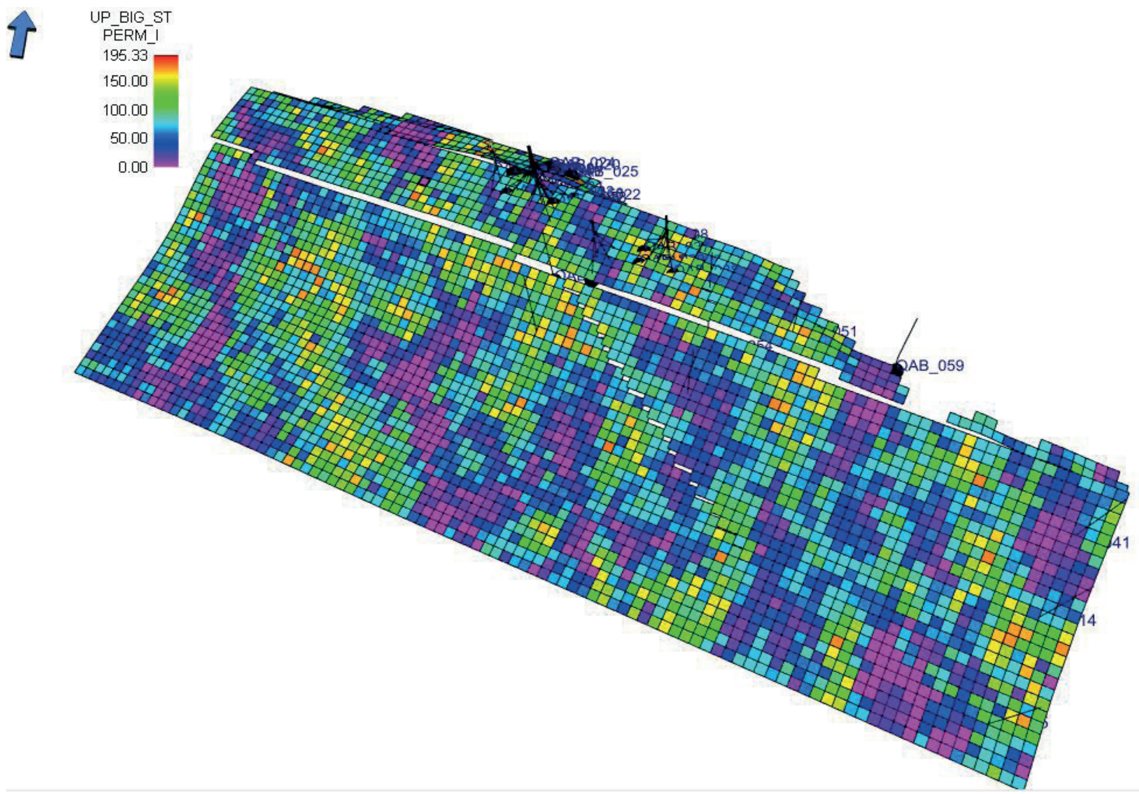

Figure 8. 3D Permeability model

A simplified J-function method using porosity (Poro), permeability (Perm), height (H) above the free water level and petrophysical constants (a, b) was establish to build a model of water saturation (SW) (figure 9). The distribution of water (oil) saturation by horizons in the Western Absheron field is shown in figure 10.

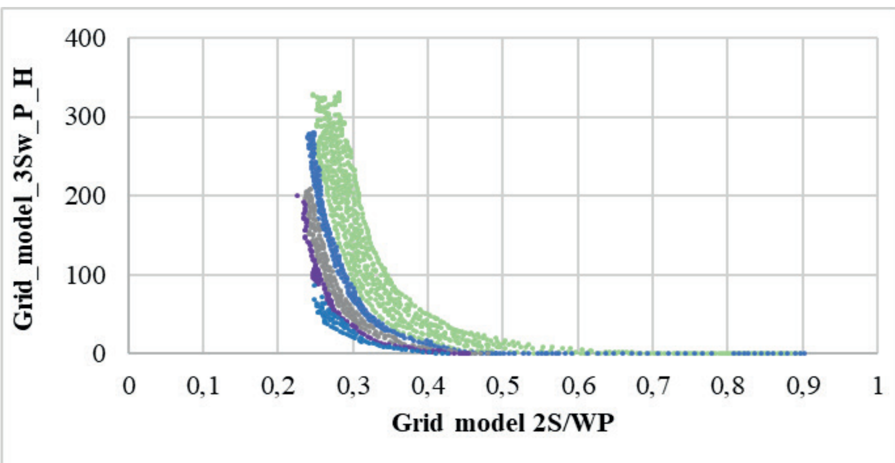

Figure 9. Skatterplot set between SW on horizons and height (H) above free water level

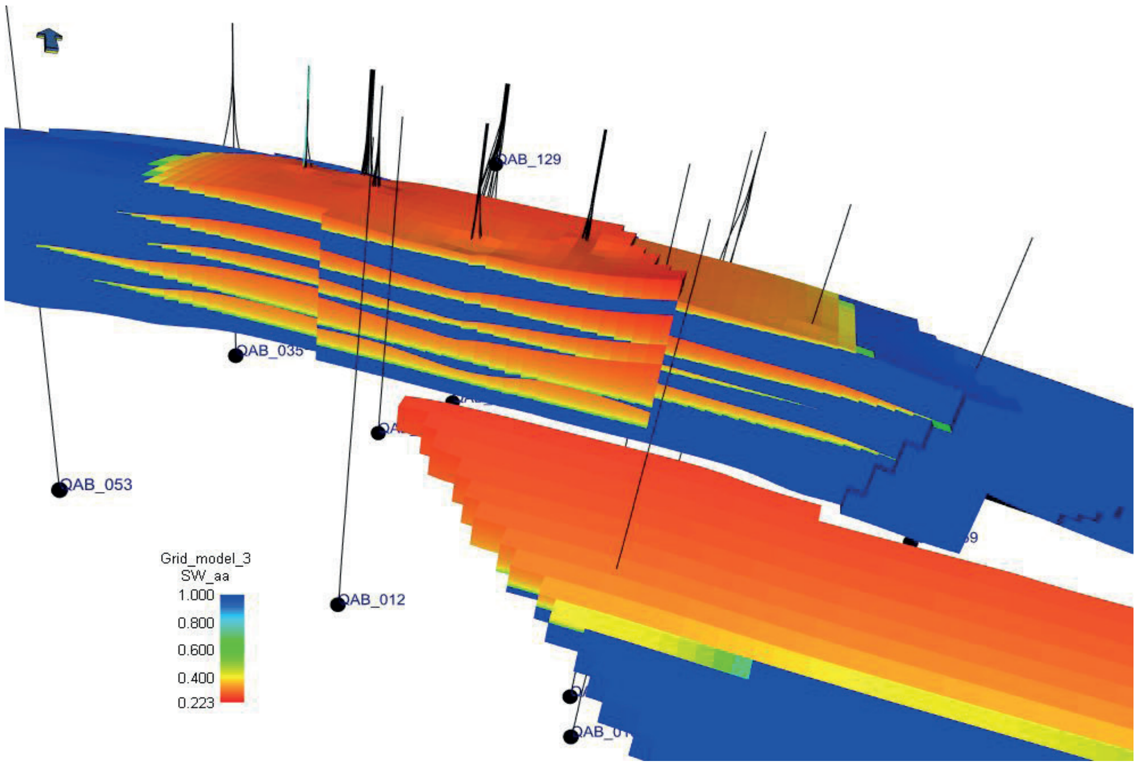

Figure 10. 3D saturation model

After the petrophysical cube is ready, the necessary parameters for the calculation of the oil reserves of the Western Absheron field along the horizons have been determined. Oil and gas effective thickness, porosity and water saturation coefficients were taken based on the results of well data interpretation, as well as the results of the petrophysical model built based on these results. The values of the mentioned parameters are given in table 3.

Table 3. Values of reserve calculation parameters

Horizon	Porosity factor			Water saturation	
	Min	Max	Medium	Min	Medium
QÜG	0,11	0,28	0,20	0,24	0,34
QD1	0,11	0,28	0,21	0,22	0,35
QD2	0,11	0,27	0,21	0,23	0,35
QD3	0,11	0,28	0,21	0,23	0,35
QAD	0,11	0,28	0,21	0,23	0,35

The determination of the initial oil volume coefficient (Bo) was based mainly on the results of the analysis of samples taken from the first exploration wells drilled in the field[19,20,21,22] and was accepted as stable for all horizons.

In the map and model constructed according to the calculation plan, oil-water contours are shown in cross-sections both horizontally and vertically (figure 11).

Given that some fractures in the area have non-conductive properties, it is normal for fluid contacts to be located at different depths in the modeled horizons and blocks. The depths of the oil-water contacts (OWC) have been determined separately for each block and the horizons they are divided into (table 4). In determining the contacts, mining-geophysical indicators and production data from wells have been used.[23]

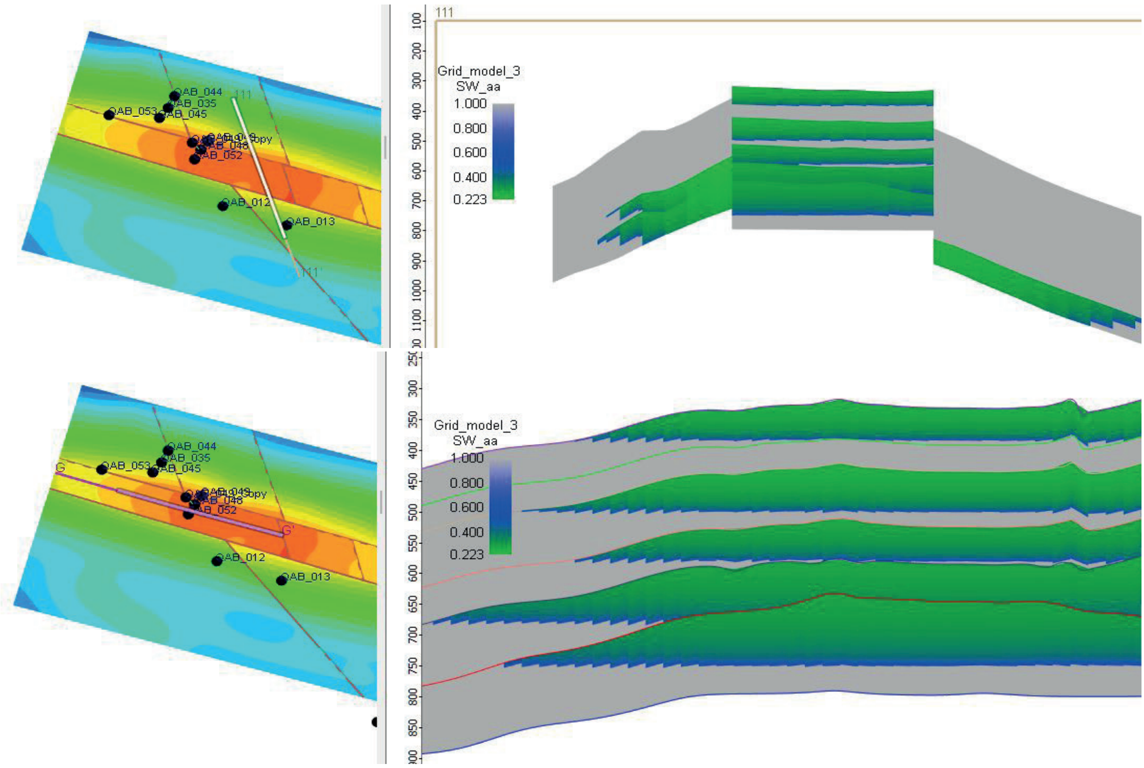

Figure 11. The general appearance of fluid contacts in the longitudinal and transverse cross-sections noted in the saturation map of the horizons

Table 4. Information about the depths of the oil-water contacts (OWC) for the horizons

Horizon	Oil-water contact (OWC) depth for tectonic blocks, in meters						
	1	**2**	**3**	**4**	**5**	**6**	**7**
QUG	0	0	375	384	0	0	0
QD1	0	0	510	500	670	0	0
QD2	0	0	560	580	770	750	0
QD3	0	0	652	680	900	835	720
QAD	1116	1205	0	750	900	0	0

Using the parameters listed above - such as porosity, thicknesses, saturation, depths of oil-water contacts, and the physical-chemical properties of oil and gas - the initial balance reserves of hydrocarbons in the productive horizons of the Western Absheron field and the tectonic blocks created by fractures in these horizons have been estimated.

Hydrodynamic Model Construction

To construct a hydrodynamic model, the three-dimensional geological model must first be loaded into the hydrodynamic simulator. To achieve this, the geological model must be prepared for loading into the hydrodynamic simulator. Very small-sized geological cells (grids) with millions of units are not suitable for conducting hydrodynamic calculations. This is because, in a hydrodynamic model, filtration equations are solved for each grid, incorporating dependencies of the physical-chemical and thermodynamic properties of formation fluids on pressure, phase permeability variation functions, and other factors. This leads to an increase in the number of calculations to an excessive extent, resulting in a very long computation time. To increase and optimize computation speeds in a hydrodynamic simulator, the number of grids in the model should be reduced. For this reason, when the geological model is loaded into the hydrodynamic model, the more detailed geological 'grid' should be replaced with a relatively coarse hydrodynamic 'grid' that has a smaller number of elements, in other words, it is necessary to transition from the geological model to a hydrodynamic framework with larger grid sizes. Note that the framework of a hydrodynamic grid is constructed based on the same structural model, and this process is called "upscaling".

When upscaling the geological model of the Western Absheron field, the number of cells was reduced along the horizons with isotropic distribution in the vertical direction, while the cell sizes were doubled in the X and Y directions. When constructing the hydrodynamic grid, 8-point cells were used instead of the geological grid, and the cells were confined by vertical boundaries. Each fault has been accounted for in the grid by applying a 50 % column adjustment. This method allows for the replacement of a precisely constructed geological grid with a relatively coarse hydrodynamic grid, i.e., one with fewer cells, which enables the equations of fluid flow to be solved more quickly in each cell.

During the transition from the geological grid to the hydrodynamic grid, several options were examined to determine the optimal cell sizes in the X and Y directions, with the goal of preserving vertical and horizontal heterogeneities for all parameters. When the cell sizes are taken to be equal to 100 meters, the production wells do not pass through the same cell (grid), and this size is considered optimal for the X-Y directions. Considering that several wells in the Western Absheron field are producing from multiple horizons, in order to perform hydrodynamic calculations simultaneously across all horizons, cell sizes in the Z direction were also optimized, reducing the total number of cells from 1,8 million to 262 845.

Table 5. Comparison of the hydrodynamic grid with the geological grid

Horizon	Geological grid (50×50)			Hydrodynamic grid (100×100)		
	X	Y	Z	X	Y	Z
QUG	99	45	60	99	45	10
QÜQ	99	45	1	99	45	1
QD1	99	45	90	99	45	14
QD2	99	45	60	99	45	8
QD3	99	45	100	99	45	10
QAD	99	45	94	99	45	16
Sum	99	45	405	99	45	59
Total	1 804 275			262 845		

Proportional divisions of the main productive horizons in the Z direction and the quality check during the averaging of geological parameters in the hydrodynamic grid have shown that there is no significant difference between the geological and hydrodynamic grids. The absence or minimal difference provides a strong basis for conducting hydrodynamic calculations efficiently. The dimensions of the constructed hydrodynamic grid and its comparison with the geological grid are provided in table 5.

The discrete parameter NTG (net-to-gross ratio) is converted into a continuous parameter. NTG, PHIE (effective porosity), and Sw (water saturation) parameters have been averaged using an arithmetic method. The PERM (permeability) parameter has been averaged using the full tensor method. Since the permeability values vary in the lateral and vertical directions, the full tensor method was used to obtain the Perm parameter for each of the I, J, and K directions.

The quality check of the 'upscaling' between the geological and hydrodynamic grids was conducted by comparing petrophysical parameters (porosity, water saturation) using histogram diagrams, and for the facies parameter, based on the vertical distribution curve.

After the upscaling process of geological model parameters to the hydrodynamic grid was completed, the initial geological balance reserves of hydrocarbons were calculated in the hydrodynamic grid. Comparing the reserves calculated in the geological and hydrodynamic grids is a way to verify the quality of the 'upscaling' process. According to international standards for modeling the development process of fields, it is considered inappropriate to continue the modeling process if this difference exceeds 10 %. In such cases, either the construction process of the geological model or the upscaling process of the geological model parameters to the hydrodynamic grid must be re-evaluated.

The initial geological reserves of the Western Absheron field were calculated in the hydrodynamic grid and compared with the values computed in the geological model, and it was determined that the differences were within acceptable error limits.

During the loading of the geological model into the hydrodynamic simulator, the coordinates of the wells, their altitudes, inclinometrics, the depths of the water-oil contacts, the depths of the formation tops and bottoms, and the cubes of the formation permeability parameters are also incorporated into the hydrodynamic model.

It is known that the reservoir pressure decreases progressively during the production process. Since the physical-chemical and thermodynamic (PVT) properties of the reservoir product depend on pressure, changes in pressure during the production process lead to changes in the thermodynamic properties of the reservoir product. On the other hand, calculations within the hydrodynamic model are performed not only for the conditions based on the initial reservoir pressure and the initial thermodynamic properties of the fluid but also for the current pressure values at each step and the corresponding thermodynamic properties of the reservoir fluid for those pressures. Therefore, knowing in advance the regular changes of the thermodynamic properties of the formation product depending on the pressure is an important for the accuracy of the hydrodynamic model. These data are determined only on the basis of thermodynamic experiments of the formation product in laboratory conditions. Based on the experiments, the pressure dependent points of these parameters are established, and these points in subsequent calculations using the appropriate equations with special programs are adapted to the pressure-temperature change and loaded into the model as a function.

Change of PVT properties of Western Absheron oil depending on pressure was obtained from the correlation and interpolation of the laboratory experiments results based on samples taken from wells No. 22, 24 and 28.

As an example of the adaptation of the physico-chemical and thermodynamic properties of theformation product in the model, the curves showing the adaptation of the experimental values of the oil volume coefficient and viscosity depending on the pressure in the model are given in figures 12 and 13.

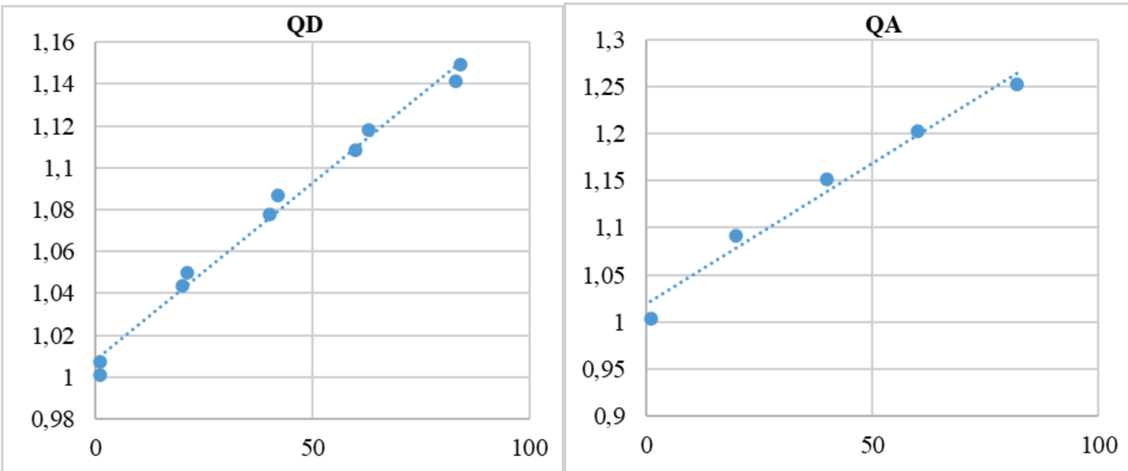

Figure 12. Adjustment of the calculated values of the oil volume coefficient to the experimental values

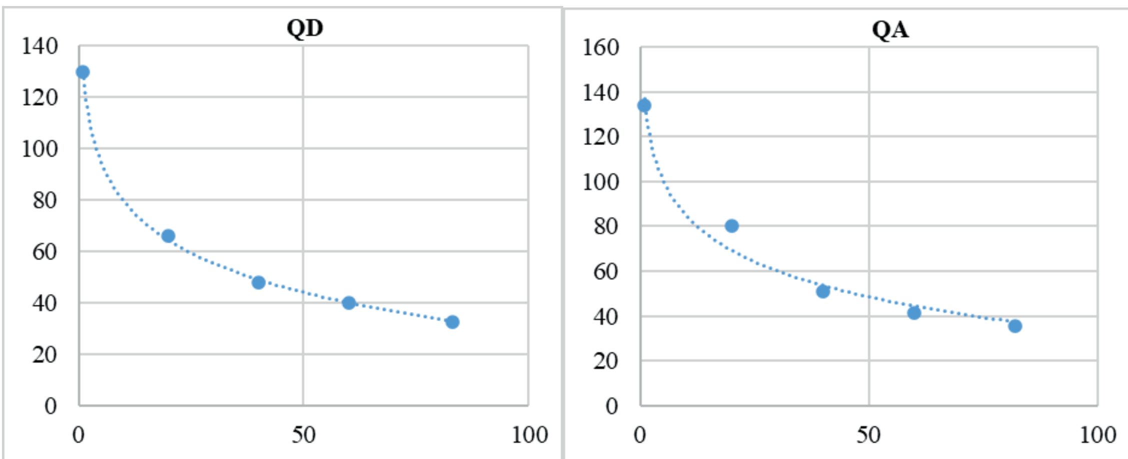

Figure 13. Adjustment of calculated values of oil viscosity to experimental values

As seen from the figures, the regular change of the physico-chemical and thermodynamic parameters of the formation product depending on the pressure is very well adapted to the values obtained as a result of the relevant tests. This creates a great basis for the proper functioning of the hydrodynamic model and accurate results in the future.

The most important parameter for the accurate operation of the hydrodynamic model and the adequacy of the predictions is the values of the relative phase permeability. The correct values of this parameter mean that the percolation equations and hydropermeabilities of the formations describe the ongoing processes more accurately and the process of predicting the performance indicators is accurate. Note that the values of these parameters are determined as a result of laboratory analyzes of core samples taken during drilling.

Since no such studies were conducted for the Western Absheron field, relevant data from similar fields were used in the model, and corrected in the restoring process of the development history. Dependencies of gas-oil and water-oil relative phase permeability used in the model are shown in figures 14 and 15.

It should be noted that “Tempest Enable” software was used to build the hydrodynamic model, and “Black oil” model was selected for calculations.

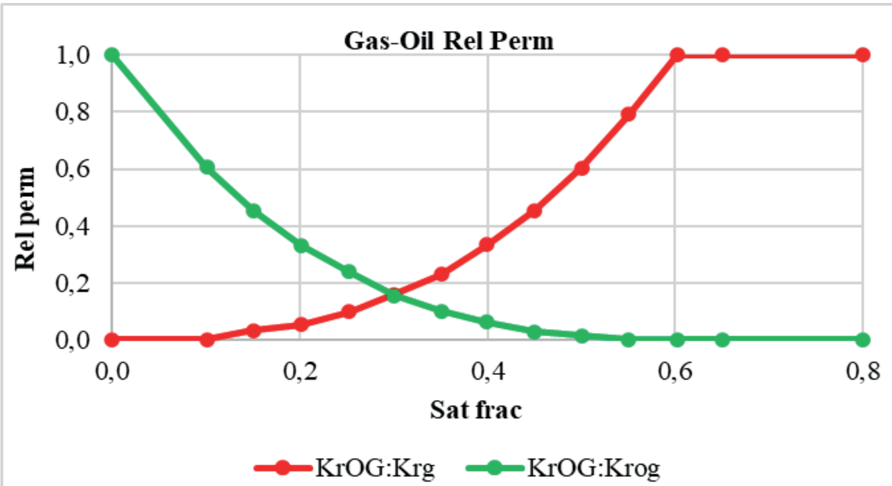

Figure 14. Gas-oil relative phase permeability used in the model

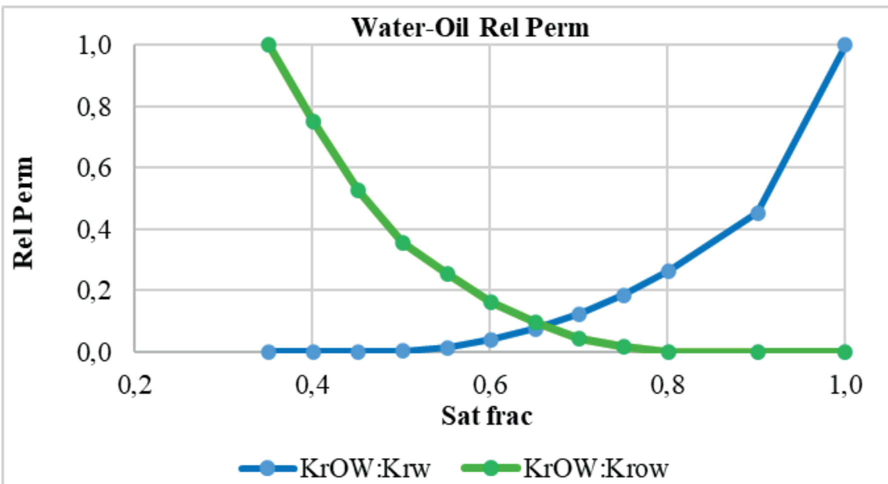

Figure 15. Water-oil relative phase permeability used in the model

After the hydrodynamic model corresponding to the initial condition of the field was ready, the development history restoring, i.e., the process of adapting the parameters included in the model to the fact, was carried out.

Since the production of oil, dissolved gas and water is considered more accurate and informative, adaptation of these parameters was taken as a basis. Production (history) recovery curves for the general Western Absheron field are shown in figure 16, 17 and 18.

Completion of the adaptation process means receiving the report of the current status of all performance parameters of the horizon. That is, the condition of the contours, the volume of the produced product, the volume of residual resources, location, etc. parameters correspond to the current state of the horizons development process.

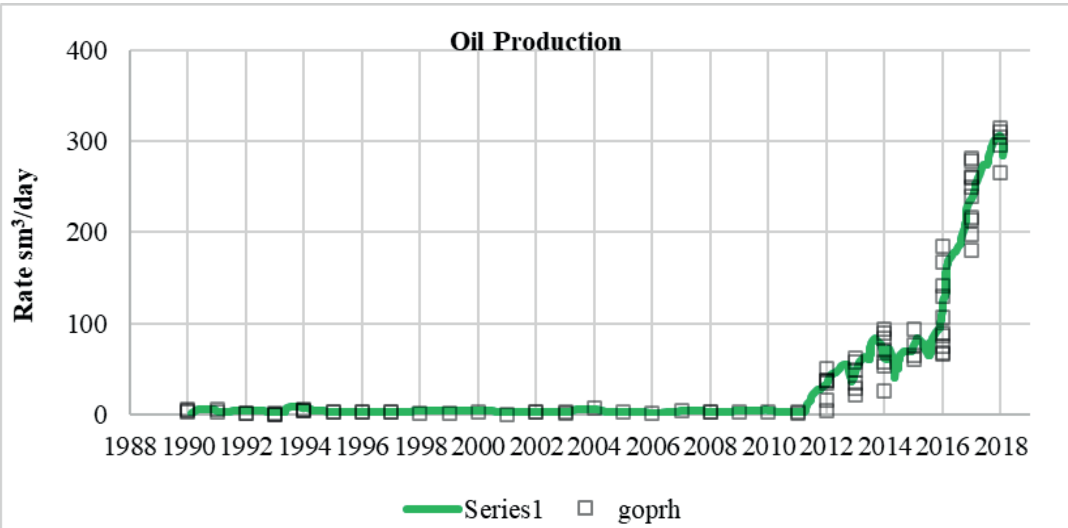

Figure 16. Oil production recovery curve

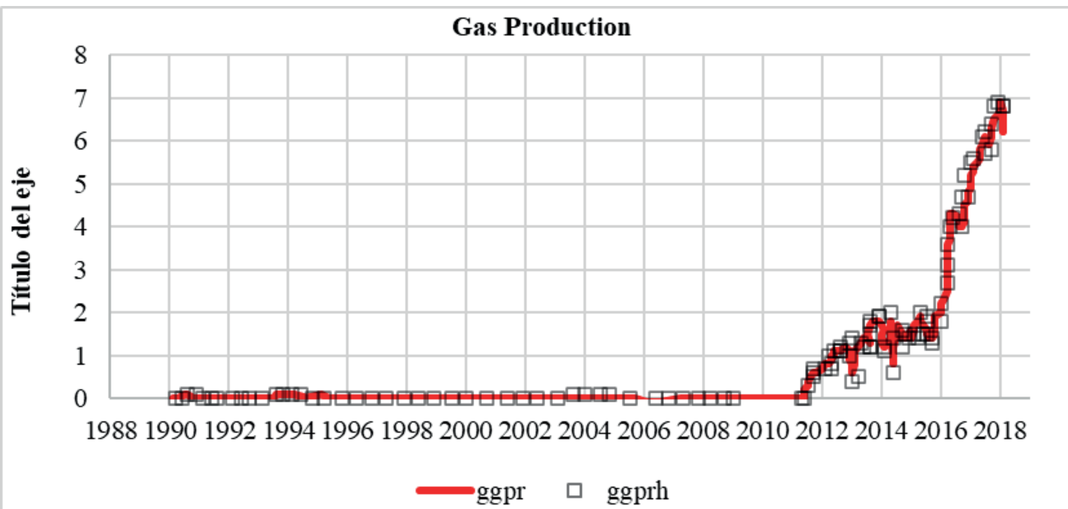

Figure 17. Gas production recovery curve

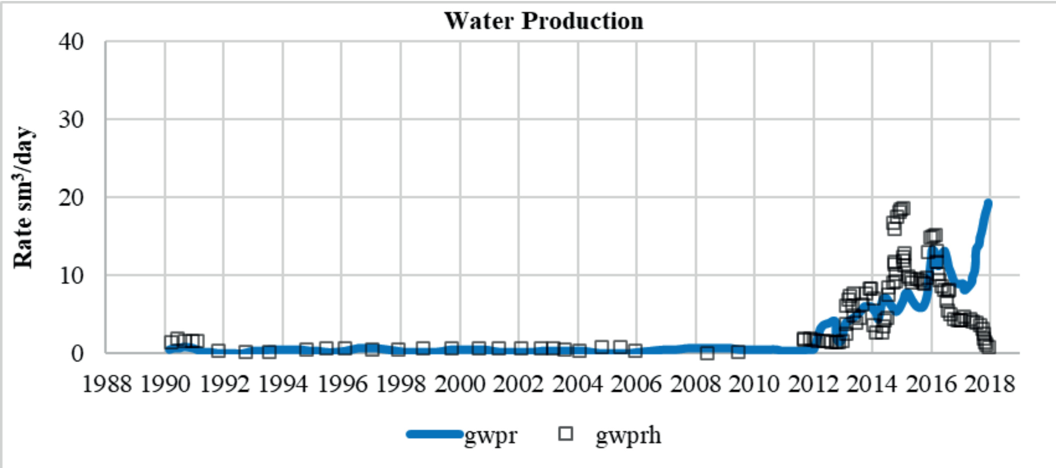

Figure 18. Water production recovery curve

The process of restoring the development history based on the hydrodynamic model, as well as the actual production data, show that currently 455 thousand m^3 of oil and approximately 10 mln. m^3 of gas were produced from QD3 and QA formation.

In the West Absheron field, production parameters up to 2050 with operating wells are predicted by the model (figures 19 and 20).

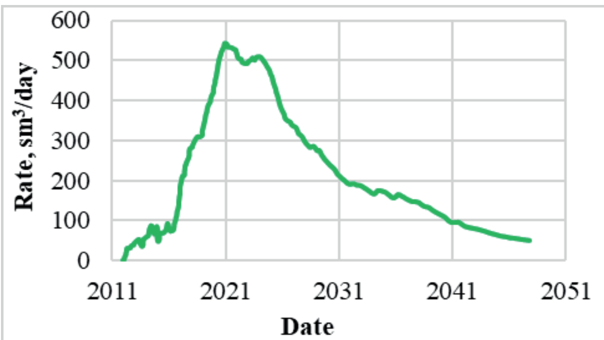

Figure 19. Prediction of the average daily oil production of the field with the existing well stock

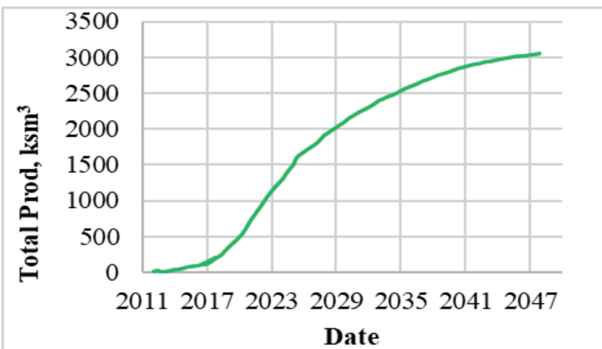

Figure 20. Prediction of total oil production of the field with the existing well stock

According to the calculations carried out in the hydrodynamic model, as seen from the figures, with current well stock a total of 1,7 mln. m^3 (QD3-1,1 mln. m^3; QAD-0,6 mln. m^3) of oil is predicted from QD3 and QA formations. This figure is a very low indicator in terms of full exploitation of horizons' resources. Therefore, in order to fully exploit the residual resources of the Western Absheron field, the issue of planning new production wells in the hydrodynamic model was considered.

For this purpose, a total of 61 new production wells were placed, 23 in the QD horizon and 38 in the QA horizon, based on the comparative analysis of different options, in the areas with the best indicators on the joint distribution map of the porosity, sandiness, thickness and residual oil saturation parameters according to the current state of the field development stage. the numbers of wells to be drilled, horizon project, commissioning dates and initial productions were determined and included in the model (figure 21).

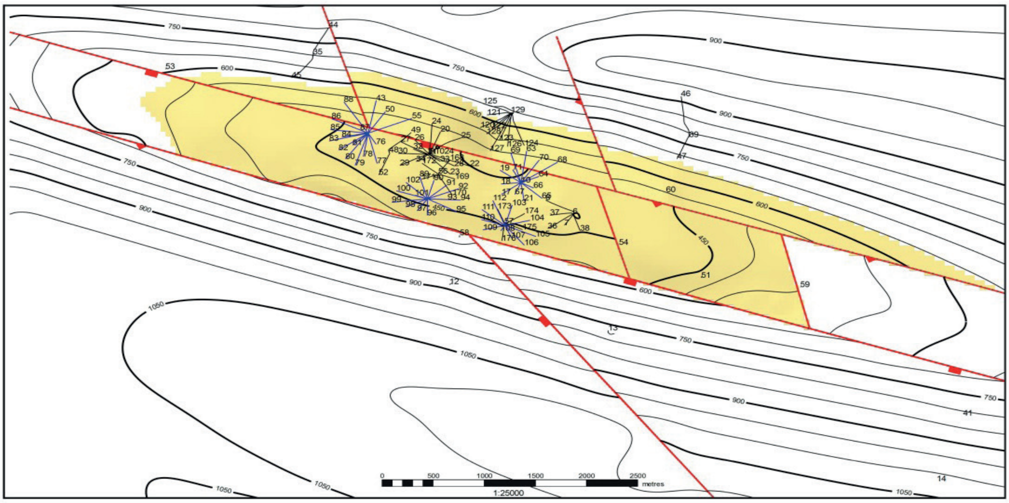

Figure 21. Location scheme of the proposed new wells on the structural map

Taking into account the new production wells, the operating parameters of the QD3 and QA formations have been predicted until 2050. The forecast of parameters is shown in figure 22 and 23. As seen from the figures, despite the new production wells being put into operation, by 2050, 3,06 mln. m^3 of oil and 496,34 mln. m^3 of dissolved gas production is predicted.

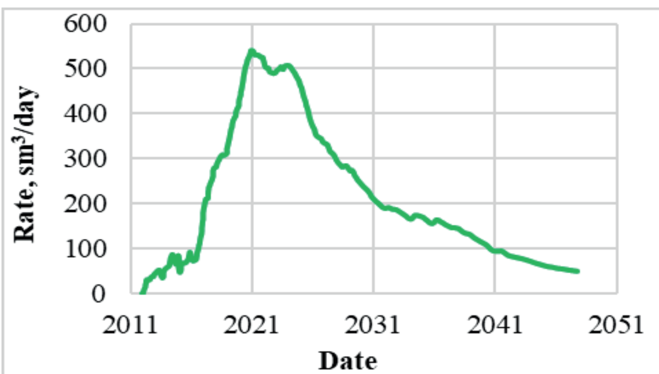

Figure 22. Prediction of average daily oil production of the field with new planned wells

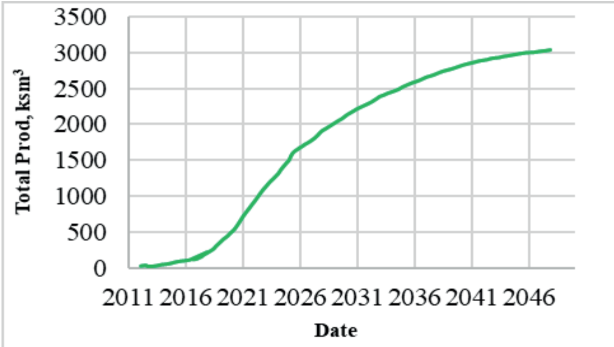

Figure 23. Prediction of total oil production of the field with new planned wells

Modeling of Stimulation Techniques

In order to increase the final recovery coefficient of the Western Absheron field, several stimulation techniques have been studied. For this purpose, the processes of injecting water, polymer solution, hot water and steam into the formation were modeled and the obtained results were compared. In order to neutralize the influence of other extraneous factors on the process, when modeling each stimulation technique, the number of new production and injection wells, start-up dates, sequences and other parameters were taken as the same for each horizon.

Water displacement: firstly, periphery injection process into QD and QA formations is modeled. For this purpose, in addition, 8 water injection wells are planned for the QD formation and 6 for the QA formation. 100 m^3/day of water was pumped from each well. It should be noted that the production parameters of the planned new production wells were also taken into account during the modeling of all formation stimulation techniques and production forecasting.

The forecast results are shown in figures 24 and 25. As seen from the figure, 3,91 mln. $m^3$of oil, 71,7 mln. m^3 gas purchase is predicted.

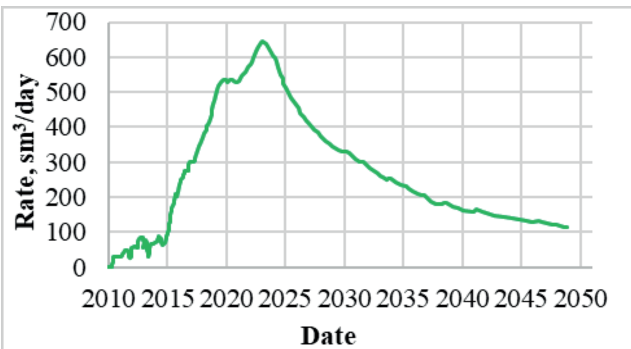

Figure 24. Prediction of average daily oil production of the field during watering by year

Oil displacement by polymer solution: to prevent the risk of water tonguing that may occur during formation stimulation and to ensure piston-like oil displacement, to ensure a decrease in the ratio between the viscosities of the displacing and displaced fluids and to bring the viscosity ratio to one, the process of displacement of high-viscosity oil from West Absheron by an aqueous polymer solution was modeled.

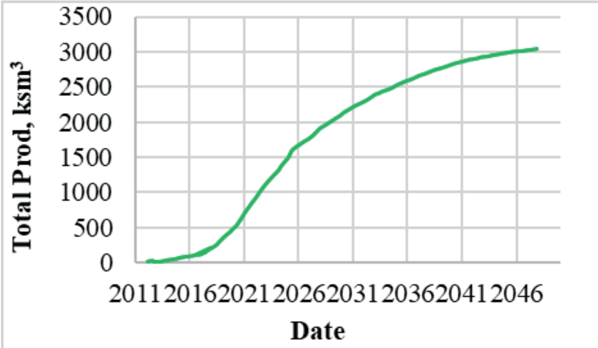

Figure 25. Prediction of total oil production of the field during watering

For this purpose, injection of polymer solution behind the contour from operating wells used for modeling the water injection process was considered. Water injection was modeled with a polymer concentration of 0,016 kg/m^3 into the layer, then the polymer solution was displaced with normal water. The law of viscosity fluctuation depending on the polymer concentration was studied in laboratory conditions, the obtained result was included in the model in the form of current factor of viscosity (figure 26). The results of predicted oil production are shown in figures 27 and 28. As you can see, it is predicted that by 2050, a total of 4,12 million m^3 of oil and 441,16 million m^3 of gas will be purchased. Current factor for oil viscosity and polymer concentration.

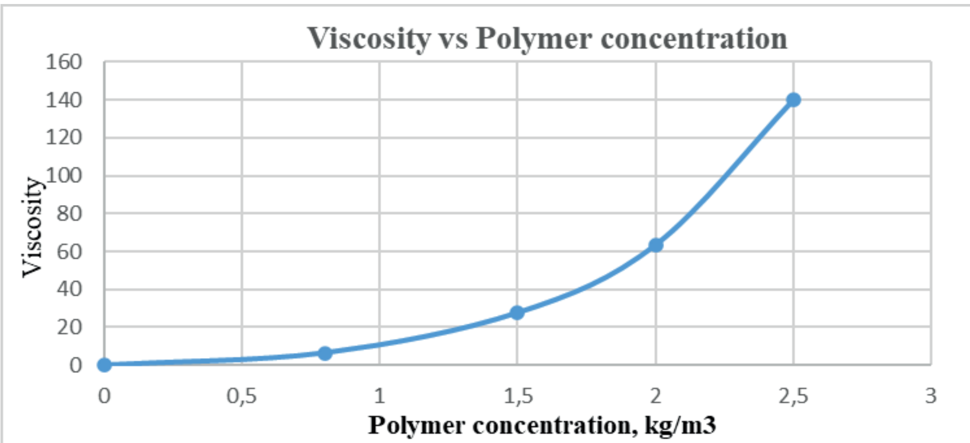

Figure 26. Graphical chart of viscosity on polymer concentration

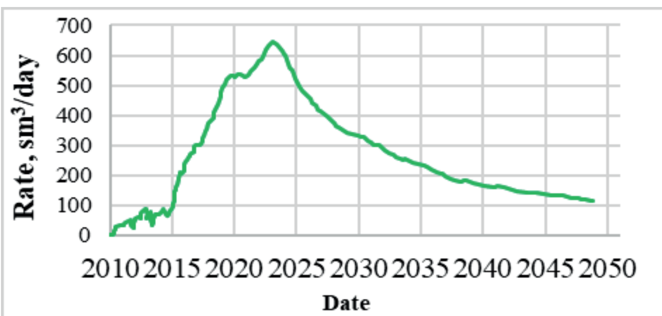

Figure 27. Prediction of average daily oil production of the field during polymer solution stimulation by year

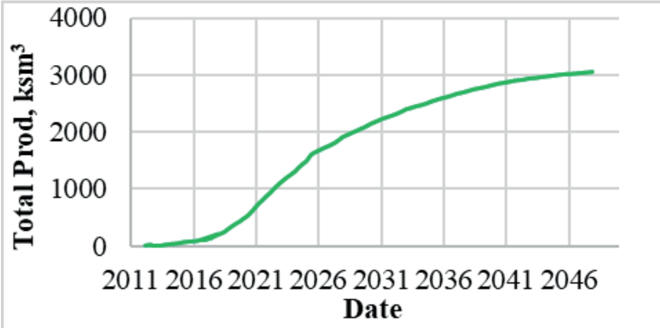

Figure 28. Prediction of field total oil production during polymer solution stimulation

Hot water injection into layers: In this option, concomitantly with the drilling of 61 new producing wells, the drilling of 14 new injection wells is planned. Of the 14 wells drilled, hot water was injected into the Kirmaki suite (QD) of eight wells and into the under-Kirmaki suite (QAD) of six wells. The regularity of viscosity change depending on temperature was studied in laboratory conditions, the obtained result was included in the model in the form of current factor of viscosity (figure 29). The production forecast results for this option are shown in figures 30 and 31. As can be seen from figure, it is predicted that 5,27 mln.m^3 of oil and 388,8 mln.m^3 of dissolved gas will be obtained from the field by 2050 during hot water stimulation into layers.

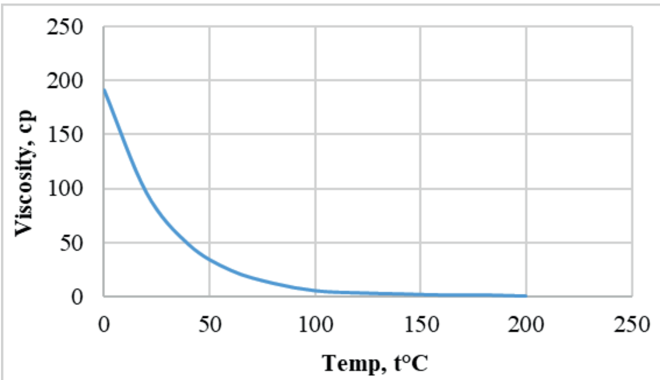

Figure 29. Temperature-viscosity curve

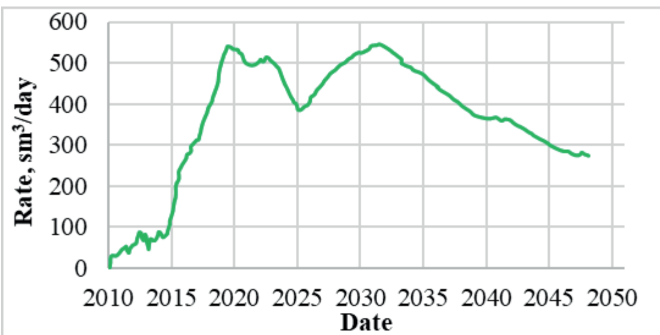

Figure 30. Prediction of average daily oil production of the field during hot water stimulation by year

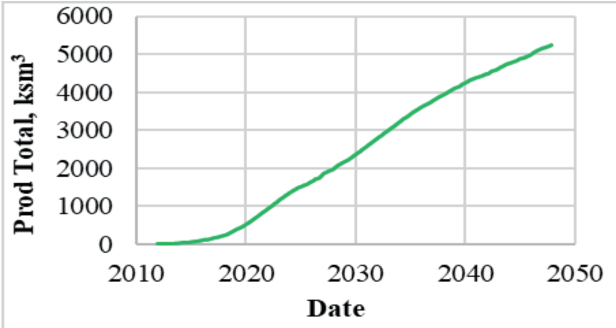

Figure 31. Prediction of field total oil production during hot water stimulation

Steam injection into layers: the mode of steam stimulation on the West Absheron field is also modeled. For this option, it is planned to drill 61 new producing wells and 14 new steam injection wells in the productive horizons of the field.

The prediction results of the steam injection option are shown in figures 32 and 33. As can be seen from figure, it is predicted that 4,05 mln.m^3 of oil and 412,0 mln.m^3 of dissolved gas will be obtained from both layers by 2047 during the steam stimulation into layers.

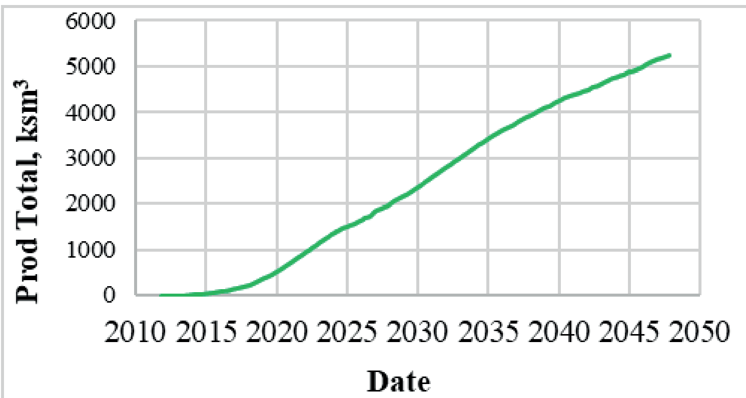

Figure 32. Prediction of average daily oil production of the field during steam stimulation by year

Figure 33. Prediction of field total oil production during steam stimulation

Thus, based on a complete modeling of the development process of West Absheron field, 6 different development options were proposed with 4 methods of formation stimulation (water, polymer solution, hot water and steam) - only with active wells stock (basic option); with active wells stock and planned new producing wells; active wells stock, planned new producing wells with various methods of formation stimulation are predicted and the predicted parameters obtained for a certain period of development are compared (table 6).

A more accurate decision can be made on which of the modeled methods of formation stimulation is more efficient and to be applied in West Absheron field after conducting feasibility report.

Table 6. Comparison of productions with different methods of formation stimulation

n	Calculation options	Total oil production, mln.m^3	Total gas production, mln.m^3	Additional oil production, mln.m^3	Additional gas production, mln.m^3
1	Base Option	2,36	191,05	-	-
2	Planning Wells	3,06	496,30	0,70	305,25
3	Water injection	3,91	442,50	1,55	251,45
4	Polymer	4,12	441,20	1,76	250,15
5	Hot water	5,27	388,80	2,91	197,75
6	Steam	4,05	412,00	1,69	220,95

CONCLUSIONS

Based on geological, geophysical and field data, geological and hydrodynamic models of West Absheron field were developed, initial geological reserves were estimated, and the development history was restored in the hydrodynamic model.

Based on the results of similar studies conducted at similar fields, the dependencies of phase permeabilities of gas-oil and water-oil ratios were developed for the productive horizons of West Absheron field and corrected in the process of restoring the development history.

Using the hydrodynamic model, the issue of choosing the optimal formation stimulation method was studied, development parameters were predicted in 6 different options, and the obtained results were compared.

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CONFLICT OF INTEREST

None.

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