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ORIGINAL PAPER - PRODUCTION ENGINEERING

Applying the hydrodynamic model to optimize the production for crystalline basement reservoir, X field, Cuu Long Basin, Vietnam

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Abstract

Weathered and fractured crystalline basement is known as the important unconventional reservoir in the Cuu Long Basin. Naturally fractured reservoir plays a crucial role in oil exploration to contribute for hydrocarbon production in Vietnam. However, the complexity and heterogeneity of the fractures system in the basement reservoir are challenges for oil and gas production. They require the realistic simulation scenarios to estimate the hydrocarbon potential as well as field development plan of these reservoirs. Thus, this paper aims to propose the feasibility development scenarios to improve oil recovery factor for crystalline basement reservoir, X field, Cuu Long Basin, Vietnam. First, history matching process is validated for the model to fit the actual production data (reservoir pressure, pressure, water cut in each well) in order to approach closer the fluid flow behavior through the reservoir. The manual matching was selected to adjust the actual aquifer size and permeability distribution with limit simulation runs. Next, the highest reliability matching model which approximately reflects the actual fluid flow behavior can be used as the base case to forecast the future reservoir performance through the field development plan. The most potential scenario is to add six new infill production wells, two side track wells and two water injection wells. The forecasted results indicate that this scenario yields 8% more oil recovery factor compared to the natural drive with thirteen producers. This result suggests that the precise field development plan is to increase the efficiency of the production process by increasing the displacement parameters of residual oil and reservoir sweep efficiency by stimulation. The major contribution of this paper demonstrates the merits of the field development plan in fractured basement reservoir. The findings of this study can help better understand the fluid flow behavior using the production history profiles and field development scenarios of crystalline basement reservoir of Cuu Long Basin.

Keywords Crystalline basement · Cuu Long Basin · Field development plan · Production optimization · Vietnam

Introduction

The average oil recovery around the world is 35%. Improving oil recovery strongly depends on the availability of technology, economical and practical field development plan (Babadagli 2007). Moreover, the chance of exploring the conventional reservoir in giant fields remarkably decreased (Blaskovich 2000). Therefore, the exploration and production hydrocarbon field turned into unconventional reservoirs. Recently, the oil and gas industry in Vietnam has focused on the fractured basement reservoir. This reservoir contributes up to 90% of oil production compared with conventional reservoir (Giao et al. 2011). Recently, many studies determined many aspects of unconventional reservoirs using experimental and numerical simulation (He et al. 2019; Qiu et al. 2019; Tan et al. 2019). Tan et al. (2019) proposed the new and simple method of measurement to investigate the criticality of fluids confined in nanopores. Also, Qiu et al. (2019) introduced a useful technique to investigate the phase transition of pure fluids and mixtures in nanopores. In the numerical simulation for shale gas, He et al. (2019) applied

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the theoretical approach of material balance to determine the original gas-in-place of shale gas reservoir.

Generally, the characteristic of basement reservoir is that it could not perform like sandstone reservoir. The current issue is to design effective reservoir management through field development strategy. There are several studies conducted for basement reservoirs such as the matrix and fracture characterization (Dakhelpour-Ghoveifel et al. 2018; Saboorian-Jooybari et al. 2015, 2016), well test analysis (Dejam et al. 2018; Mashayekhizadeh et al. 2011; Zhang et al. 2018) and overview of geological and production characteristic (Gutmanis 2009). Moreover, the history matching process is one of the challenges for unconventional and basement reservoirs (Azim 2016; Dachanuwattana et al. 2019; Dang et al. 2011; Jeong et al. 2013; León Carrera et al. 2018; Nguyen et al. 2011). These authors proposed an efficient workflow to handle the difficulty of modeling and history matching in fractured basement reservoirs. However, a field development plan is one of the crucial tasks that can enhance reservoir performance and maximize economic value that has not yet been mentioned in the case of basement reservoir. In recent years, many studies have focused on numerical simulation for improving oil recovery in unconventional reservoirs (Alfarge et al. 2018; Izadmehr et al. 2018). Alfarge et al. (2018) introduced the way to select the best type of miscible gases to enhance oil recovery in shale oil reservoirs. Furthermore, Izadmehr et al. (2018) considered the injector rate, number and installation of submersible pumps to rank the development scenarios for the oil field.

For crystalline basement reservoir, the bottom hole pressure needs to maintain through natural drive mechanism in the reservoir. It is called the primary stage in production oil field's life cycle. This stage is not efficient if the reservoir manager has not proposed an effective plan. Conventionally, reservoir engineers advise on the field development plan through sensitivity simulation studies (Khan and Awotunde 2018). Recently, many researchers have given much attention to field development plans for production optimization (Ashraf et al. 2019; Isebor and Durlofsky 2014; Santos et al. 2017; Wilson and Durlofsky 2013; Yang et al. 2017). Ashraf et al. (2019) in integrated well log and 3D seismic attributes to evaluate the potential development area. This study predicted the spatial distribution of sweet spots of the heterogeneous reservoir in Sawan gas field, Pakistan. Also, Yang et al. (2017) also presented a hybrid algorithm for field development in a mature oil field. This work stated that well conversion schedules are essential for economic field development scenarios. Also, Isebor and Durlofsky (2014) employed particle swarm optimization-mesh adaptive direct search to maximize expected reservoir performance considering the risk associated with the worst-case scenario. Another study was proposed by Santos et al. (2017) for optimal production strategy significantly to increase the expected value of objective function while reducing the downside risk. Moreover, Wilson and Durlofsky (2013) adapted the surrogate modeling procedure to optimize the field development scenarios considering net present values in Barnett Shale.

However, production optimization through field development has not been proposed in crystalline basement reservoir. Therefore, this paper considered the crystalline basement reservoir in X Field, offshore Vietnam for field development design through optimization of oil production.

First, materials and methods are presented. The history matching process is conducted to validate the reservoir model using water cut, bottom hole pressure and tubing head pressure of each well. The history matched model used for the field development strategy through multiple simulation scenarios, precisely well spacing, water injection, infill drilling, artificial lift design. The selection of the most potential scenario is based on improving oil recovery and economic aspects for a future development plan in crystalline basement reservoir. Figure 1 depicts the sketch of this workflow.

The main difference between this work and previous studies is the simple and efficient procedure for history matching and field development plan for crystalline basement reservoir. The manual history matching process could be achieved after several simulation runs by changing aquifer size and permeability distribution. Moreover, the field development plan considered the natural drive mechanism and an artificial system option to enhance well performance. They result in higher economic value of the future development plan as well as the risk mitigation for production operation in real field. Due to flexibility and efficiency of this work, it could be easily applied in other basement reservoirs in Cuu Long Basin or other basin.

To the best of our knowledge, the presented process of this field development plan had never been conducted in the literature, especially in crystalline basement reservoir.

Geological background

The X field is located on the boundaries of the two licensed blocks (09-1 and 09-3) on the south of Vietnam continental shelf, 135 km from the Vung Tau Port and 110 km from the nearest coastline. Vung Tau city is connected with Ho Chi Minh city by a highway (distance 125 km), as well as by a waterway that is accessible to practically all the types of vessels (distance 80 km).

The general location map is shown in Fig. 1. Exploration drilling in the area was carried out with jack-up rigs. The power supply sources for drilling are internal combustion engines. Sea depth in the area is 25–50 m. Water temperature varies in a year from 250 to 320 °C. The water salinity is 27–35 g/l.

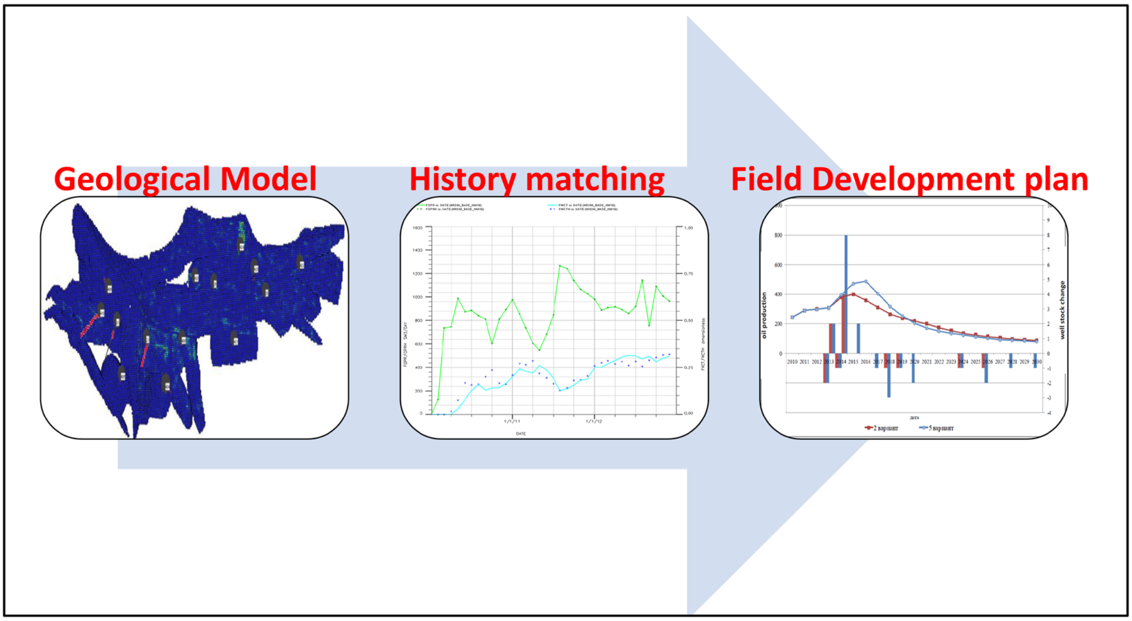


Fig. 1 The general sketch of this study

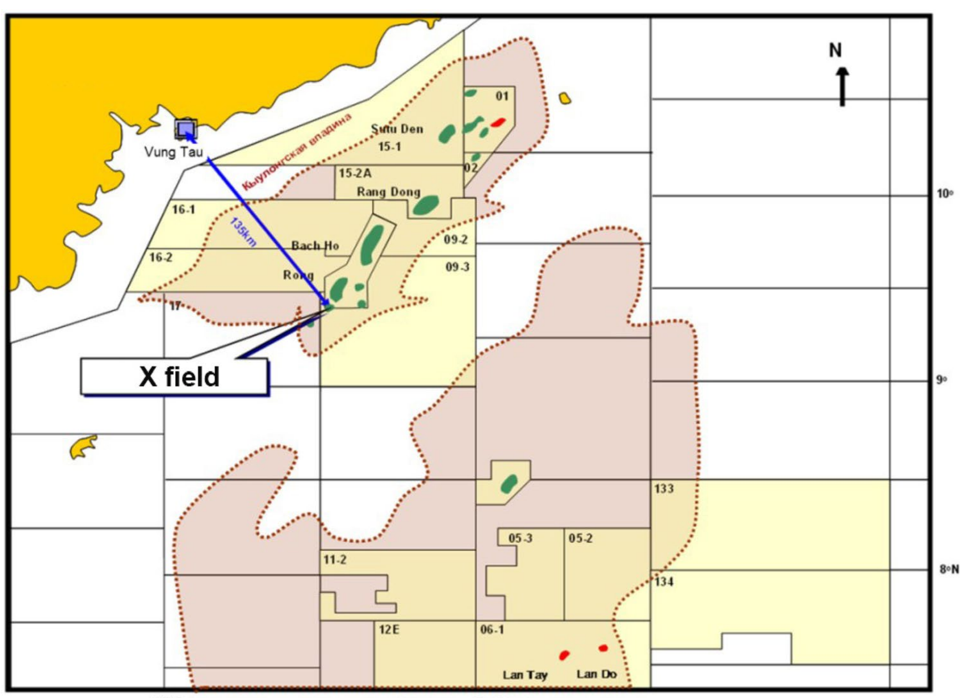
In tectonic terms, the above-mentioned tectonic element is a central horst, which formation is closely related to rifting and the development was activated since the early Cenozoic period and determined by the presence of the three different structural columns: basement (Mesozoic), intermediate (Paleocene) and sub-platform (Miocene–Quaternary) in the section.

The general stratigraphy of X field is following:

The X geological section is represented by crystalline basement rock and Paleogene (Oligocene), Neogene (Miocene, Pliocene) and Quaternary sediments (Fig. 2).

According to geophysical data, thickness of sedimentary cover in area varies from 3.3 to 3.8 km at the top of the

Fig. 2 Location of studied area in Cuu Long Basin



most uplifted structures (by well data) to 5.0 km at the most subsided parts of grabens (by seismic data).

According to the core materials, the basement within the block is represented by biotite gneisses, gneissoid granites and hornblende diorites of bright gray, subjected to weathering and metamorphism in different levels.

The open void of gneisses was studied only in eight colored slices. Average value of the open cavitation is about 1.58% at variation of 0.8–2.8%. It was practically solely formed by fractures (1.53%), and the porosity is negligibly small – 0/04%.

Materials and method

The OIIP of X Field for 2P reserves is 34.172 MM SM^3. Until the end of November 2012, the cumulative oil produced from this reservoir reached 930994 SM^3, and cumulative water is 257,421 SM^3. Currently, there are a total of 14 wells with 13 wells producing oil. The field has been producing oil from January 2010.

During exploration phase, four samples were taken: 20, 25, 2X and 3X. The carefully analyzed laboratory data were used to match PVT models applying PVTi modules. The PVT data taken from well 25 were selected for simulation model. Figure 3 depicts a summary of matching results of key PVT parameters such as formation volume factor, oil viscosity and liquid density.

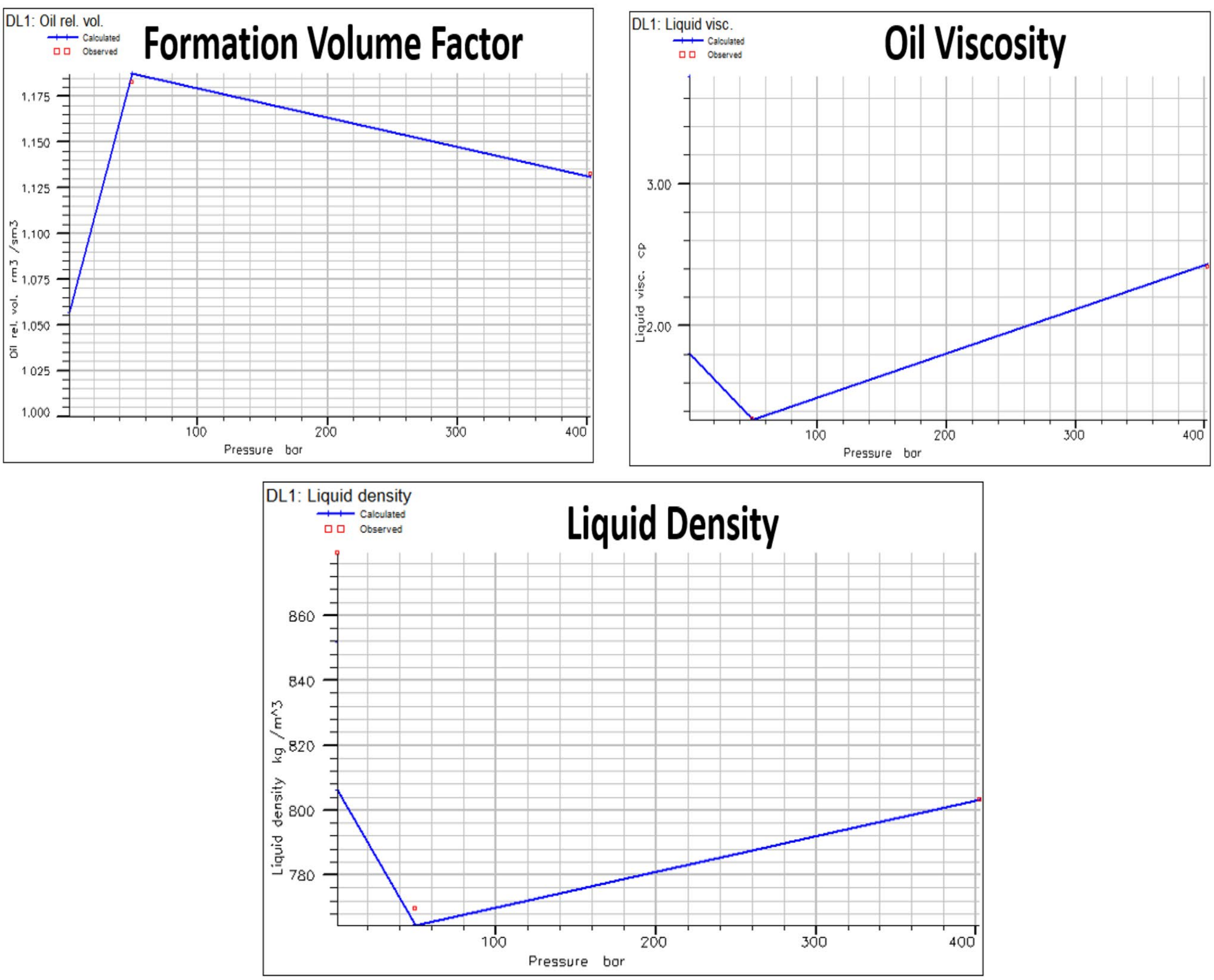


Fig. 3 Summary of matching result of key PVT parameters

Table 1 Oil characteristics from well R25

Oil type	Black oil
Bubble point, Pb	49.5 bar
Oil density at Pb	796.8 g/cc
Oil viscosity at Pb	1.35 cp
Oil formation volume factor at Pb	1.183 (m^3/SM^3)
Initial oil formation volume factor, Boi	1.133 (m^3/SM^3)
Solution gas	25.16 (m^3/m^3)

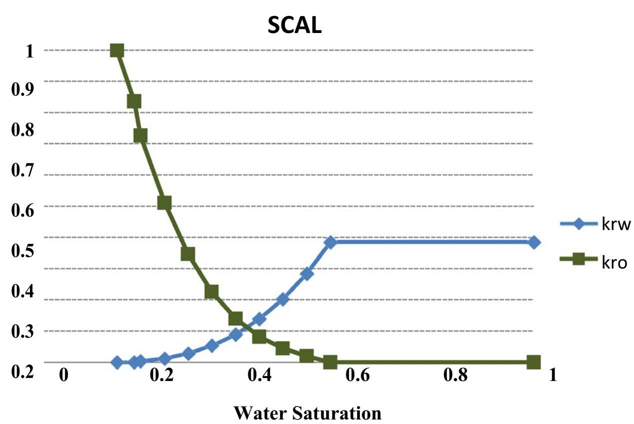


Fig. 4 Water–oil relative permeability curve

Oil properties

The main characteristics of the basement reservoir fluid from well R25 are shown in Table 1.

Rock properties

The water–oil relative permeability and gas–oil relative permeability curves using in X basement reservoir simulation were approximately replicated (analog method) from Bach Ho field. The final data of relative permeability is shown in Fig. 4.

The reservoir simulation in this study was done using ECLIPSE Black Oil Simulator. History matching was conducted in order to validate with the actual production data. The best history matching models were used to predict further development scenarios and improve oil recovery (IOR) planning in crystalline fractured basement reservoir. Several options from field development will be performed to determine the suitable strategy for reservoir management. Comparing case by case through reservoir simulation provides the optimal plan to maximize the oil recovery.

Field development plan considered the primary to the secondary stage of the reservoir. Therefore, the proposed field development design in this work would provide the efficient procedure to optimize production in crystalline basement reservoir.

The details of options for field development are as following:

- *Option 1* (base case): considering the non-interruption of the field development in the current conditions and in the existing regime
- *Option 2*: considering the addition to the base case by adding four producers and two sidetracks and converting two wells into injectors.
- *Option 3*: considering the addition to the base case by adding six producers and two sidetracks and converting two wells into injectors.
- *Option 4*: considering the addition to the base case by adding eight producers and two sidetracks and converting two wells into injectors.
- *Option 5*: considering the addition to the base case by adding ten producers and two sidetracks and converting two wells into injectors.

To perform these options, related to the impact of the linear (buffer) pressure, bottom hole pressure, the commencement date of water injection, the required level of voidage ratio, selection of candidate wells convert into injector and their number, additional intermediate calculations had been conducted:

- Bottom hole pressure: 100 at/tubing head pressure: 16 at
- Selection of number of wells and candidates: 2 or 3 injection wells
- The candidates of transfer underwater injection: 405, 406, 420, 422
- The level of voidage ratio: 60%/70%/80%/90%/100%;
- The beginning of water injection: 2014/2015/2016/2017.

The location of each new well and its profile can be updated with the new geological field data obtained after accomplishing previous development and current status of the field development.

Hydrodynamic model

The model dimension is 338 × 120 × 27 ($X \times Y \times Z$). It is modeled by 1,095,120 cells, including 213943 active cells. The dimension of cells is 30 m × 30 m × 30 m (DX × DY × DZ). In addition, the initial field reservoir pressure was determined from pressure survey data at 400 atm at depth of 3950 m TVDss. The initial temperature was ranged from 120 to 137 °C.

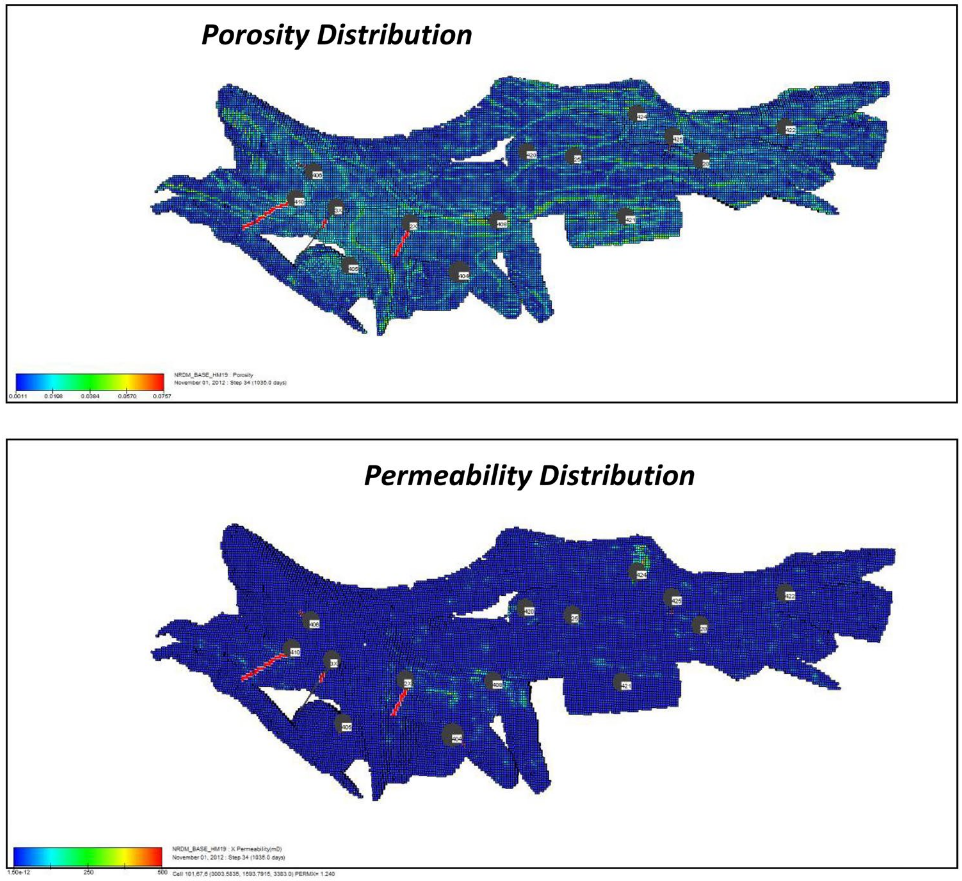


Fig. 5 Distribution of porosity and permeability model

Table 2 Comparison between OIIP defined by volumetric method and dynamic model

Volumetric calculation	Dynamic calculation	Difference
OIIP (MMSM^3)	OIIP (MMSM^3)	%
34.172	33.49	1.9

Moreover, the reservoir is highly heterogeneous with fracture distribution in geological models. The reservoir models are up-scaled directly from high-resolution static model. Figure 5 highlights the distribution of porosity and permeability in crystalline fractured basement reservoir.

In order to quality control the difference between static and dynamic model, the comparison between initial oil in place in the simulation model by using the approved number of oil in place determined by volumetric method shows in Table 2. The difference between volumetric calculation and dynamic calculation is only 1.9%. This result indicated that the dynamic calculation could be used for further evaluation.

Results and discussion

History matching

Before individual wells are matched, we ensured firstly that the field matching is up to the satisfaction. This is to ensure the validity of our history matching procedure. It is to be reminded that not all the wells are calibrated to achieve the history matching; we are focusing only on some key wells which mainly contribute to field oil production. After initialization is completed and validated, we proceed to the history matching phase. Since there are a lot of uncertainties with this model, critical parameters were identified and sensitized to check the overall effect toward the performance of the field as well as among the producing well.

In this study, the sensitivity variables being matched for the simulation are aquifer support and permeability distribution.

In order to obtain the good match, some modifications on aquifer support and permeability were applied; gas lift volume and VFP tables were also specified to match the tubing head pressure. History matching results for field water cut and WBHP, WTHP, WWCT and WBP9 and also by

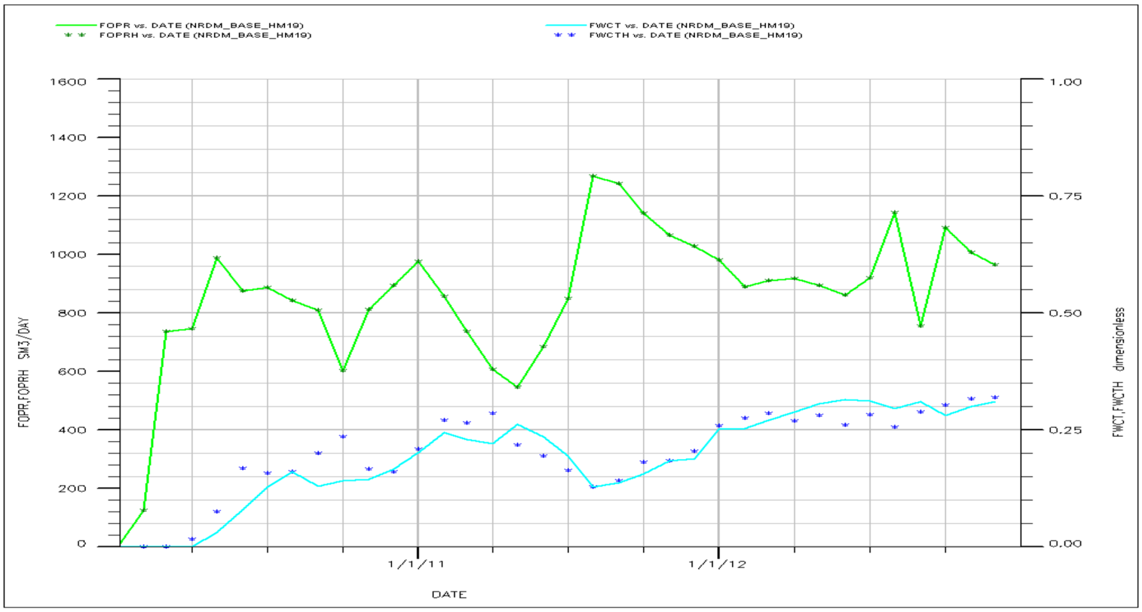


Fig. 6 Field matching results

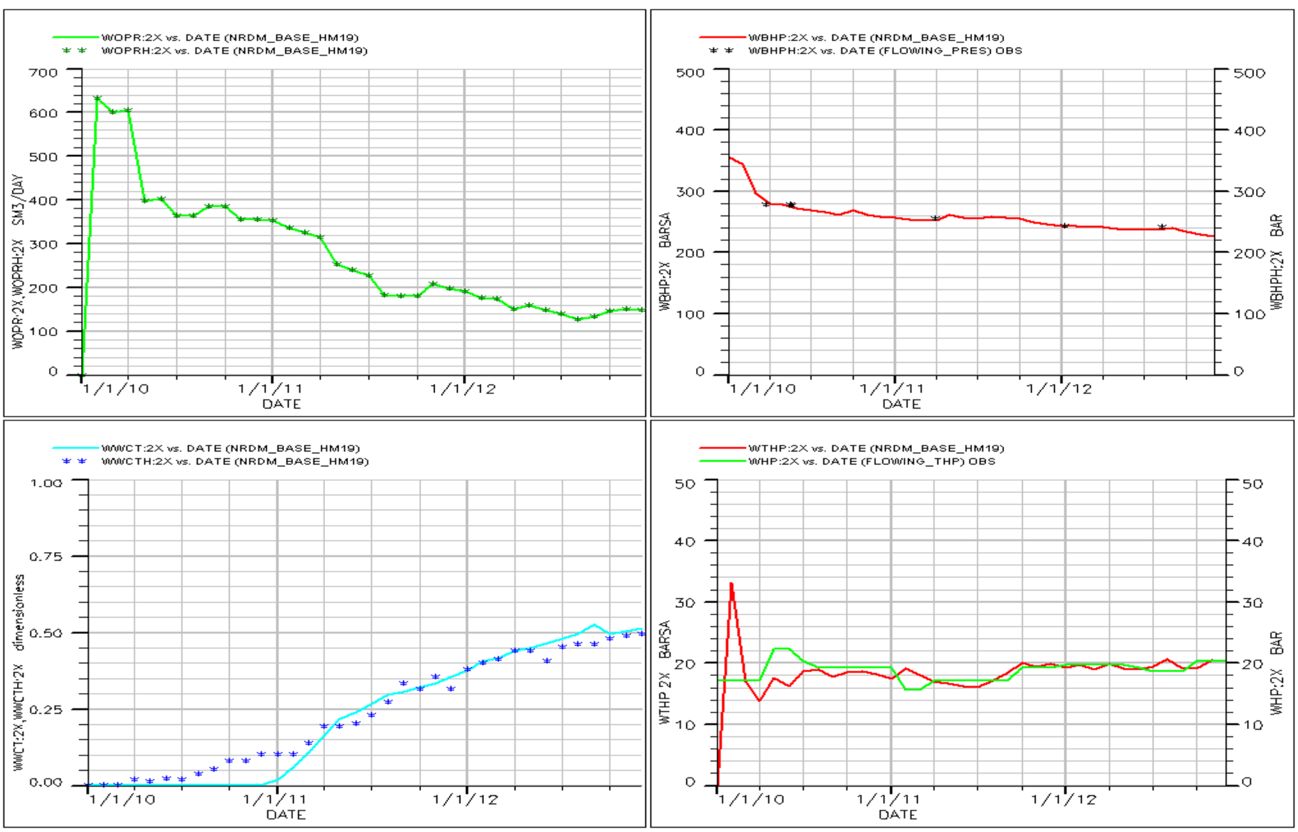


Fig. 7 Matching results of well

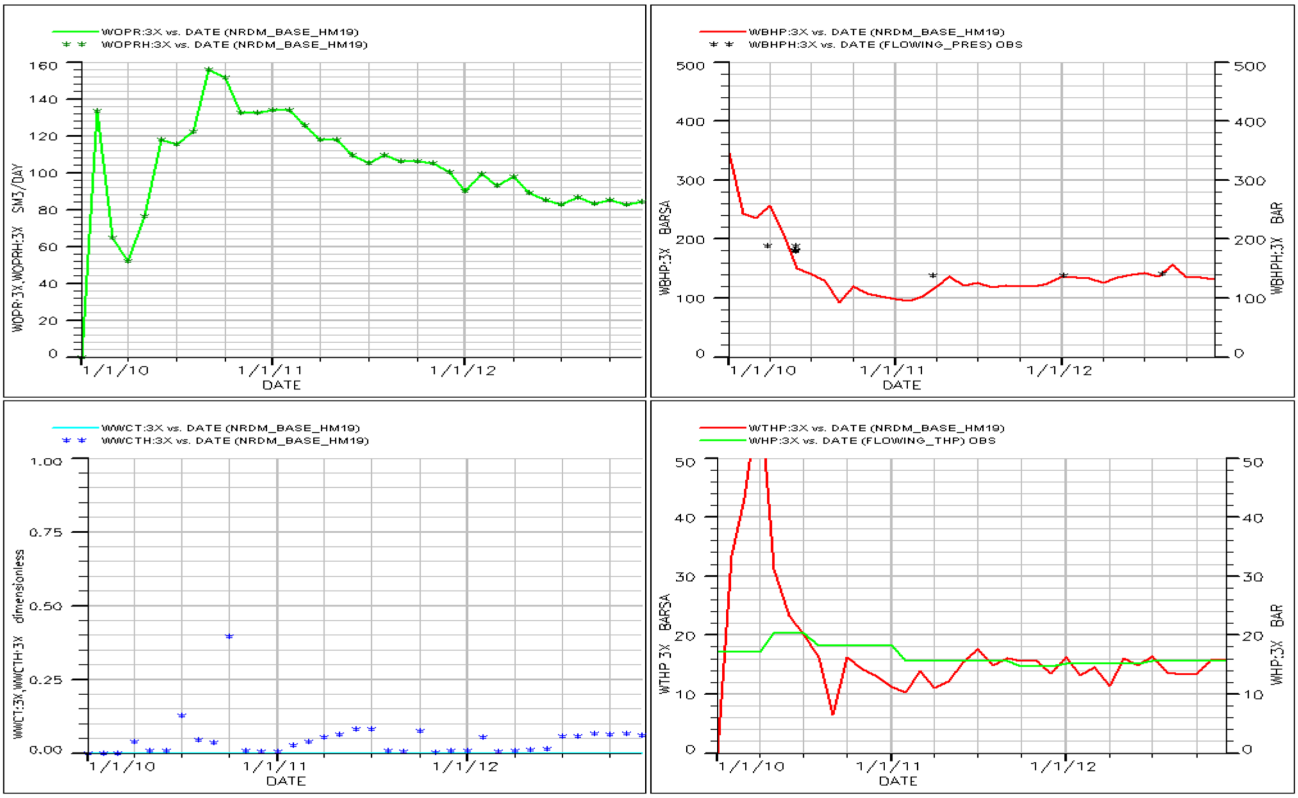


Fig. 8 Matching results of well 3X

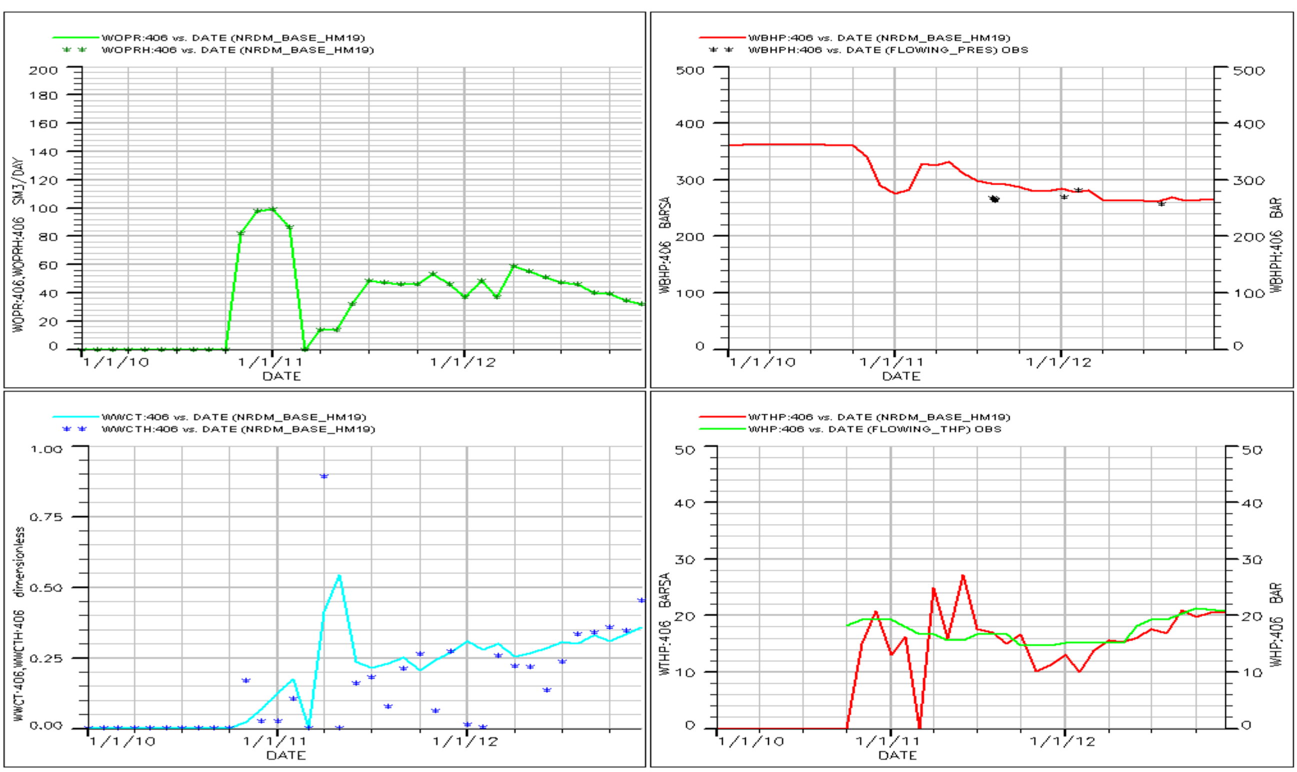


Fig. 9 Matching results of well 406

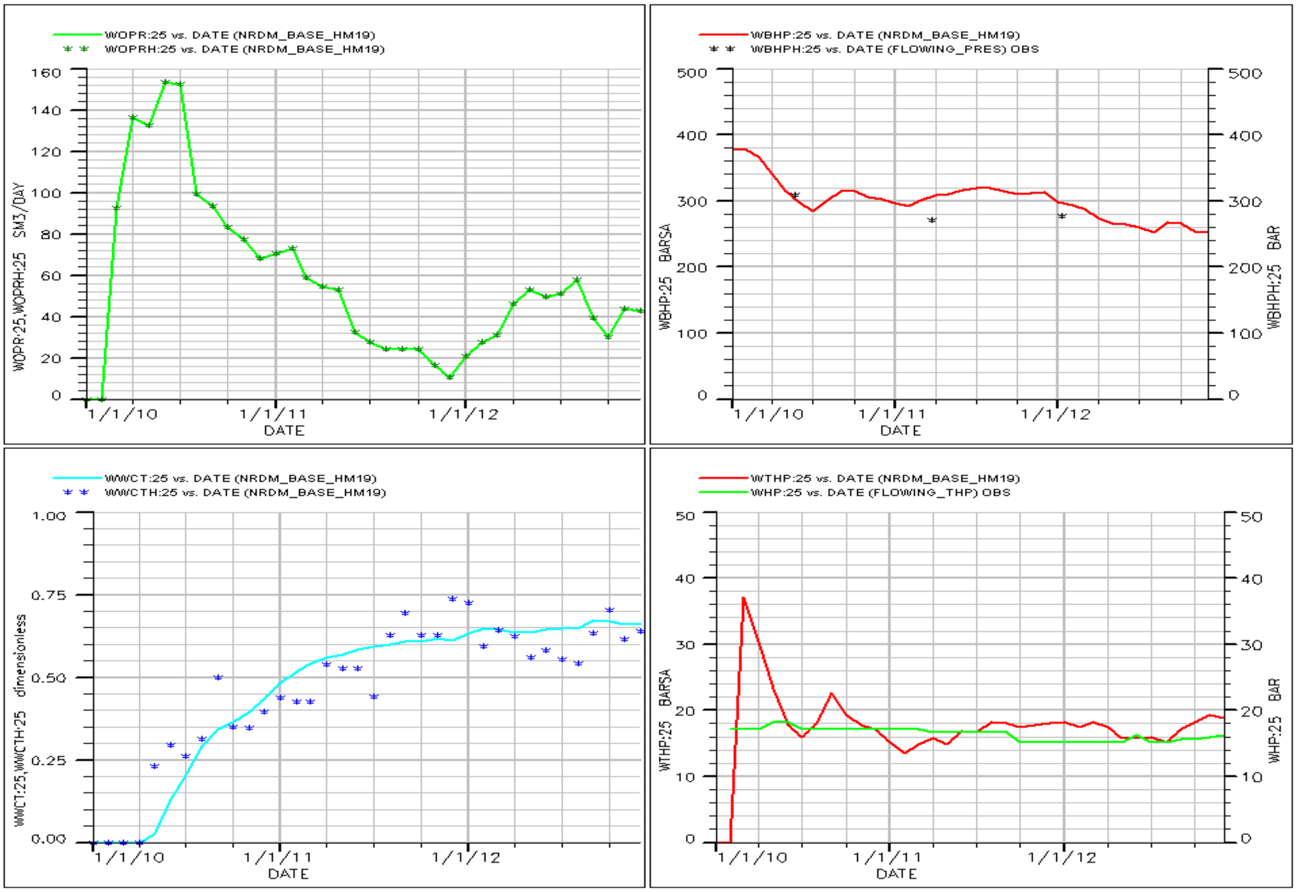


Fig. 10 Matching results of well 25

individual wells (85% of wells) showed a good match and are presented in Figs. 6, 7, 8, 9, 10 and 11.

It was unnecessary to apply an optimization tool for assisted history matching because the matching in this work was conducted through the small number of runs after adjusting aquifer size and permeability distribution. The mismatch between simulated and observed results in Figs. 5, 6, 7, 8, 9 and 10 to emphasize the effects of history matching process while calibrating the aquifer size and permeability model.

Figure 12 depicts the cross-validation of cumulative oil and liquid production. The nearly perfect matching between calculated and observed data is good indicator to reflect reservoir fluid flow behavior in crystalline basement reservoir. Thus, the validated reservoir model could be used to predict future reservoir performance and field development plan.

Field development plan

The average daily maximum injectivity of injection wells is assumed to be 600 m^3/day according to the data of pilot injection. It is considered for conversion when the oil flow rate is 2 t/d or maximum water cut is 98%. The proposed options on the hydrodynamic model showed the following:

Option 1 (base case) considers the non-interruption of the field development of the oil reservoir by the natural energy. Reservoir development is characterized by sublinear reduction of oil rates associated with the reservoir pressure drop and increasing water cut.

Option 2 (base case + 4 new wells + 2 sidetracks + 2 injection wells) considers the increase in the well number (drilling wells 407, 409, 423, 426), sidetracking from wells 404 and 421 and the organization of the reservoir pressure maintenance system (wells 406, 420)

Option 3 (base case + 6 new wells + 2 sidetracks + 2 injection wells) considers the same measures as the option 2, but with further increase in the well number by 2 (drilling wells 411 and 427). This scenario is most similar to the scenario 3, which was recommended for applying in the EPP 2007. The well number is 20 wells, including 18 production wells and 2 injection wells. On each WHP 2 reserve slots will remain.

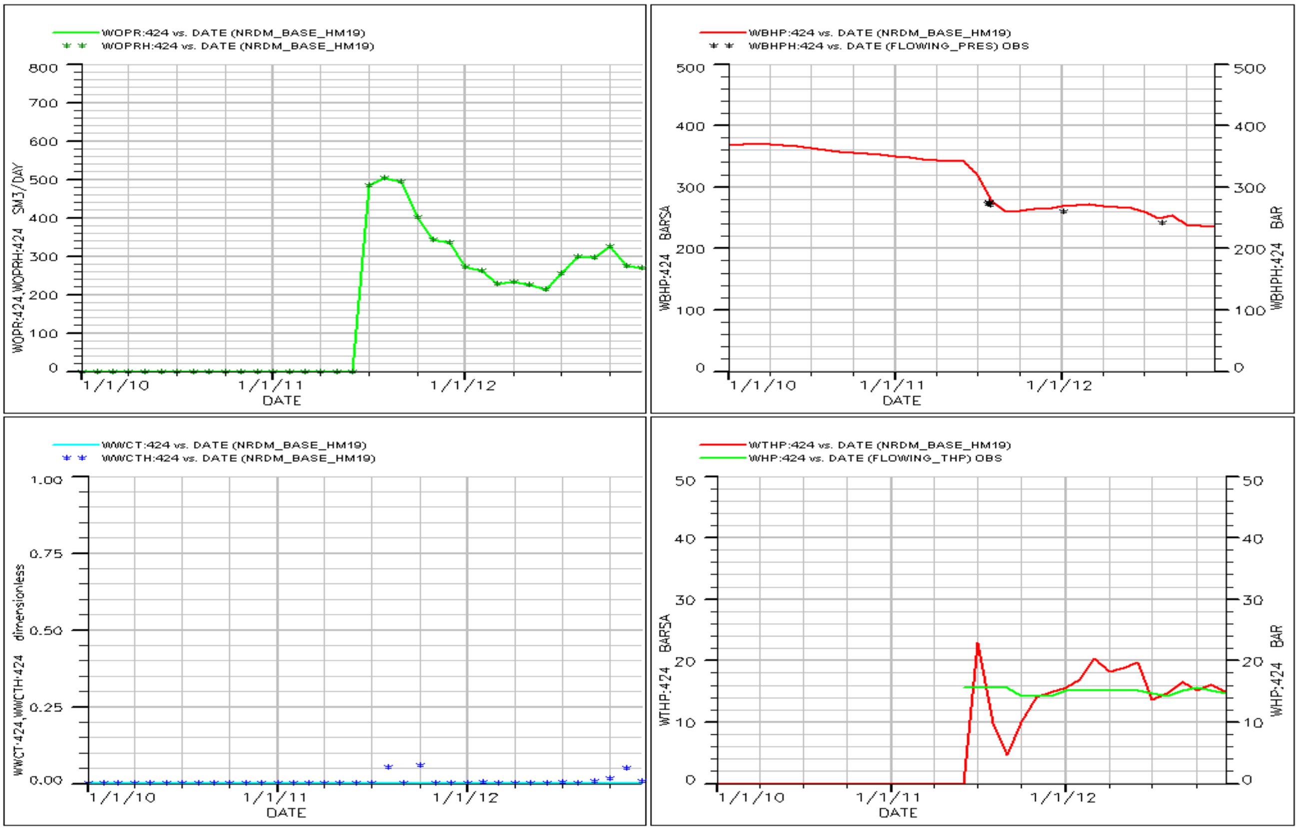


Fig. 11 Matching results of well 424

Option 4 (base case + 8 new wells + 2 sidetracks + 2 injection wells) in contrast to the previous option, it considers the addition of two wells.

Option 5 (base case + 10 new wells + 2 sidetracks + 2 injection wells) considers the maximum use of the opportunities of adding wells from WHP.

The predictive technological parameters are presented in Fig. 13. The main technological parameters of the considered options are shown in Table 3, which implies the full-rated level oil recovery reserves is achieved in case of applying the option 5.

Simulation results indicated the increase in the well number is well correlated with cumulative oil production rate l and is according to the value of the oil recovery factor, but in recalculating the recoverable oil for one well, the effect is ambiguous.

This somewhat reduces the attractiveness of this scenario. Specific volume of oil production rate in the option 2 is superior to others. This indicates the technological effectiveness of this option. Comparison of specific production rate in areas showed high effectiveness in the down spacing on RC-DM relative to RC-4 (Table 4).

The advantage of the option 5, first of all, is in ensuring the high levels of oil recovery in the coming years (5–6 years) after the beginning of works. The primary and main disadvantage is the high rate of well conversion in a short period of time (minus 7 units during the period from 2017 to 2020) and a slight increase in the recoverable oil reserves. The advantage of the option 2 is in the fullest use of the drilled well number, the optimum process of well conversion, stable dynamics of the drop of recovery rates and least costs (Fig. 14). This option is the base case for the next three options, which propose the development of one of the main statuses of the process flow diagram—drilling of new wells. Therefore, in the conditions of high geological field and economic uncertainty, the option 2 is more preferred. On the basis of the situation that will develop in the future, further development on the proposed scenarios is possible. This will allow to take a more justified decision on the down spacing. One of the possible options of the down spacing is to increase the number of sidetracks that economically costs

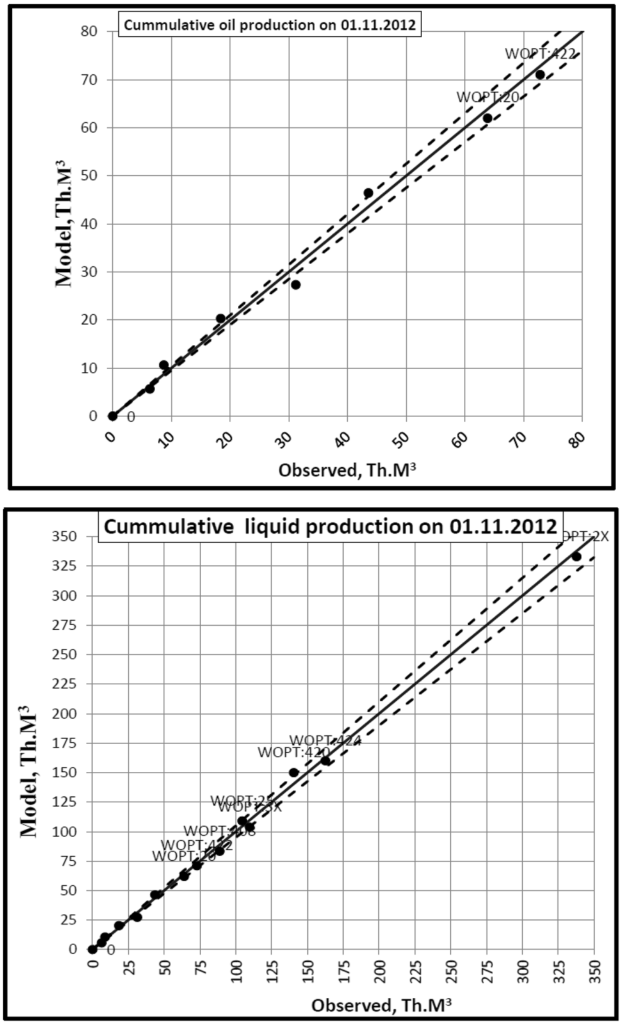


Fig. 12 Cross-plot of cumulative oil and liquid production

less than drilling a new well. Start of the well conversion is predicted in the years 2018–2019.

Comparison of the option 2 with options 3 and 4 confirms the above- mentioned observation. It should give an explanation on close enough parameters of the cumulative production rate of the options 2 and 3. At the end of the forecast period, the difference between them is only six thousand tons. This is explained as follows: the putting of new wells into production is reflected by the increase in production rate in the initial period, but later, as a result of more intense flooding, there is a reduction in oil production rates. In the end, the effect of drilling of two additional wells in the period from 2014 to 2020 is leveled by negative (according to comparison with the option 2) dynamics of the yearly recovery rates after 2021. The similar analysis of the predictive production showed signs of interference, when the operation of the new wells affected the production regime of the previously drilled wells in the reservoir.

There is a value and sequence of putting wells into production, as in the option 2, two pairs of wells (407, 423 and 409, 426) are put into production with high predictive levels of the cumulative oil (1694 and 388 thousand tons, respectively). The option 3 proposed to place two wells into production (411,427) with less cumulative indicators (335,000 tones). Moreover, in the option 4, two new wells (P1, P2) will produce 623,000 tons, while in the option 5 including the wells P3 and P4 has cumulative production rate of 323,000 tones. Thus, by changing the sequence of placing wells into production, it is possible to receive a big difference between the options, but in the level of total reserve recovery, it is reflected weakly.

It noted the complexity of the forecasting of the flooding process the conditions of fractured reservoirs of the basement reservoirs of the complicated faults. The simulation result shows that under the conditions of satisfactory adaptation of the hydrodynamic model, a sufficiently stable forecast for the next 3–5 years for oil production is ensured, but the reliability of the estimated flooding remains low due to intricately replicable process of the water movement in these geological conditions. The driving curve of X field has a good shape compared to adjacent structures (Fig. 15). After starting of the flooding process due to water breakthrough at an early stage of development, the probability of the earlier flooding of new wells is higher than the probability which was obtained on the filtration model (an average of 3 years), i.e., there is a possibility of failure to achieve predicted maximum annual recovery rates in the volumes that have been calculated previously.

Therefore, to determine the effect on the values of the oil recovery factor of the well number and the production regime, preliminary calculations (12 scenarios, Table 5) are shown.

Comparison and analysis of the results showed the following:

- Increase in the well number is reflected by enhancement of the oil recovery factor (ORF) from 0.014 to 0.023;
- Application of the reservoir pressure maintenance system leads to an increase in the ORF from 0.07 to 0.078.

After preliminary calculations, it was determined five major development options, which consider the drilling of new wells and the creation of an artificial reservoir pressure maintenance system. The greatest value of ORF is achieved in the option 5 and is equal to 0.163, which is more than 0.08 for the one obtained in the base case.

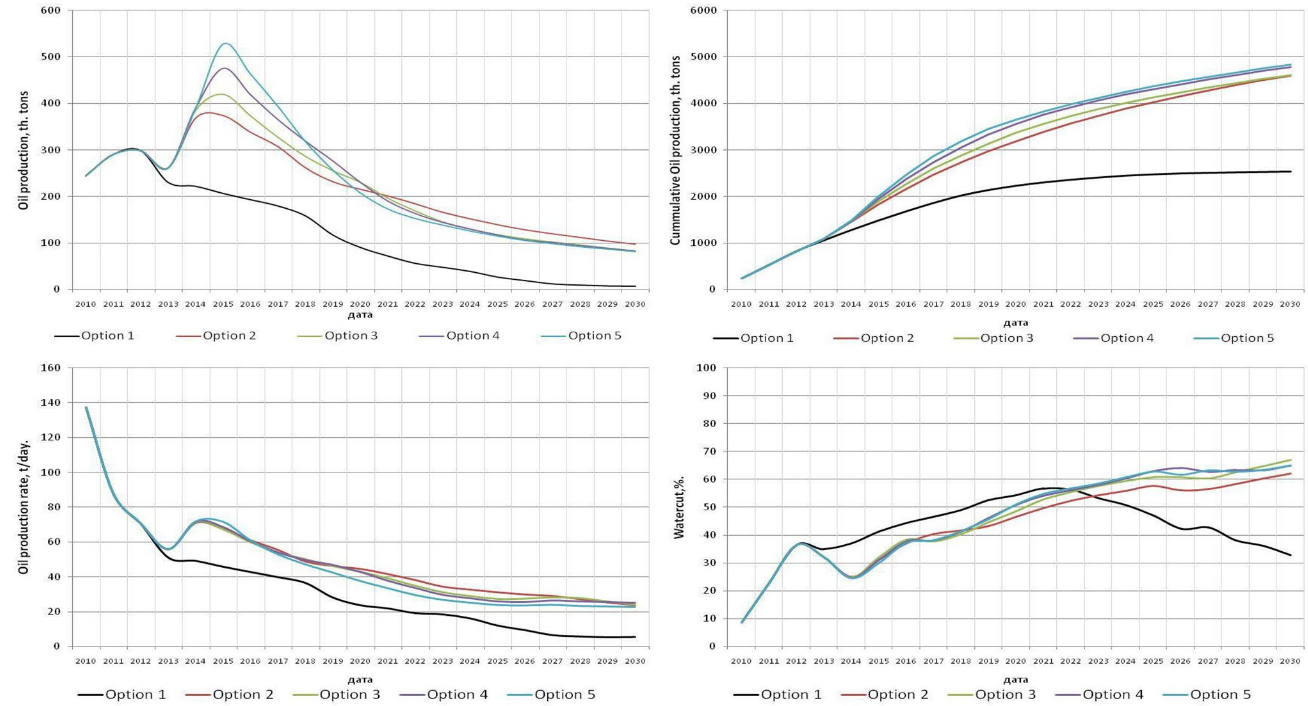


Fig. 13 Predictive technological parameters of development options

Table 3 Summary of technological parameters of the calculated options

Nos.	Parameters	Option 1	Option 2	Option 3	Option 4	Option 5
1.	Development system, type of impact	Natural drive	Water injection for reservoir pressure maintenance in the bottom part of the reservoir			
2.	Well spacing, 10^{-4} m^2	138	97	88	81	74
3.	Design production level of:					
	Oil, thousand tons	230	374	419	476	529
	Fluid, thousand tons	354	542	617	689	753
	Water injection, thousand m^3	–	301	298	311	311
4.	Cumulative oil production, thousand tons	2536	4603	4609	4789	4833
5.	Oil recovery factor	0.09	0.155	0.156	0.162	0.163
6.	Solution gas oil ratio	14	20	22	24	26
	In which: production well	13	16	18	20	22
	Injection well	–	2	2	2	2
	Sidetrack		2	2	2	2
	In suspension	1	–	–	–	–
7.	Ratio between the injection well stock and production well stock	–	0.125	0.111	0.1	0.091
8.	Production drilling, thousand (m)		20,026	28,411	37,372	45,309
9.	Average water cut at the end of development period (%)	32.9	62.2	67.1	65.1	65.0
10.	*Geological reserves for 1 well*, thousand tons	2287	1486	1351	1234	1143
	Cumulative production rate for 1 well, thousand tons	181	230	210	200	186

Table 4 Comparison of the predictive specific oil production of wells

WHP	Well	Option 2	Option 5	Δ *t* ton.	Remark
RC-4	20	231	121	-111	
	25	94	95	1	
	420	64	64	0	Injection
	421	7	7	0	
	421_ST	130	130	0	Sidetrack
	422	371	179	-191	
	423	64	621	-43	
	424	54	447	-307	
	425	80	42	-39	
	426	137	132	-5	
	427	–	161	161	Option 3
	P1	–	350	350	Option 4
	P3	–	163	163	Option 5
RC-DM	2X	362	317	-45	
	3X	293	198	-95	
	404	–	–	–	
	404_ST	156	156	0	Sidetrack
	405	57	50	-8	
	406	41	41	0	Injection
	407	643	516	-127	
	408	112	106	-5	
	409	251	218	-33	
	410	154	133	-21	
	411	–	173	173	Option 3
	P2	–	249	249	Option 4
	P4	–	160	160	Option 5
total		4603	4833	230	

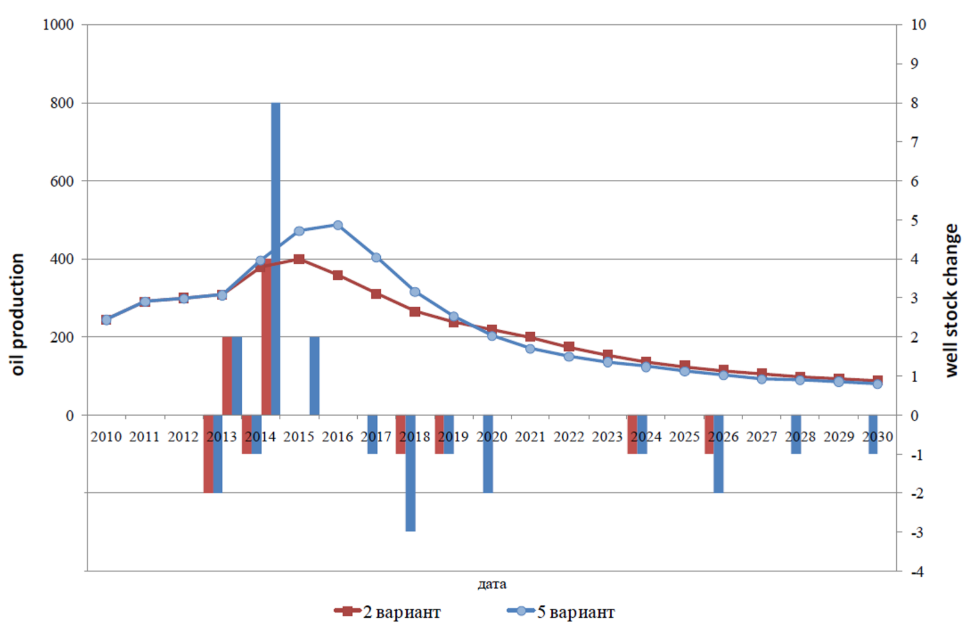


Fig. 14 Comparison of dynamics of well stock change and oil production in the cases 2 and 5

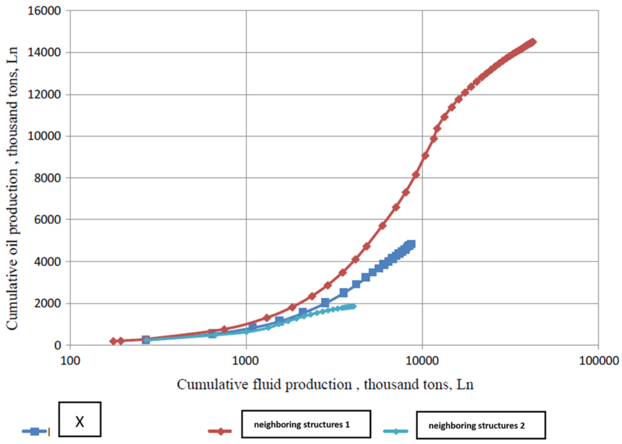


Fig. 15 Driving-out curves of blocks of neighboring structures field

The main way to improve the technology and systems of the field development is to increase the efficiency of the production process by increasing the displacement parameters of residual oil and reservoir sweep efficiency by stimulation.

Summary and conclusions

This study proposed the history matching process and field development plan to optimize oil production in crystalline basement reservoir. The key points drawn from this work include the following:

- The nearly perfect history matching model could be achieved by calibrating aquifer size and permeability distribution.
- The field development plan provides the better evaluation about technological parameters
- Water injection for reservoir pressure maintenance highly contributed to improve oil recovery in crystalline basement reservoir
- Increasing the well number is less effective than reservoir pressure maintenance in terms of oil recovery factor
- The option 5 is the optimal field development in crystalline basement reservoir of X field.
- Forecast results of production with recovery coefficients in the range of 10–13% are relatively suitable for neighboring fields.

Table 5 Comparison of the oil recovery factor depending on the well stock and production regime

Production regime	Options	Cumulative oil production (1000 m^3)	Increment to the base case (1000 m^3)	Oil recovery factor
Natural drive	Base case (13 wells)	2918	0.0	0.085
	Base case + 2 new wells	3371	453	0.098
	Base case + 4 new wells	3525	607	0.103
	Base case + 4 new wells + 2 sidetracks	3616	698	0.105
	Base case + 6 new wells.	3555	637	0.104
	Base case + 6 new wells + 2 sidetracks	3658	740	0.107
	Base case + 10 new wells	3605	687	0.106
	Base case + 10 new wells + 2 sidetracks	3702	784	0.108
Natural drive with an artificial system of reservoir pressure maintenance	Base case + 4 new wells + 2 sidetracks + water injection (406 and 420)	5302	2384	0.155
	Base case + 6 new wells + 2 sidetracks + reservoir pressure maintenance (406 and 420)	5309	2391	0.156
	Base case + 8 new wells + 2 sidetracks + reservoir pressure maintenance (406 and 420)	5517	2599	0.162
	Base case + 10 new wells + 2 sidetracks + reservoir pressure maintenance (406 and 420)	5567	2649	0.163

However, there are some limitations as follows:

X basement is type I fractured reservoir in Nelson classification which characterized as permeability and storage are in deformation structures, not the standard porous media. The reservoir may have extremely low porosity at very high permeability and extreme anisotropy of permeability. There will be no conventional relative permeability—saturation relationships that are dependent on flow velocity and direction. The extreme sensitivity of water cut to pressure and rate boundary conditions need to be considered during the history matching of the model.

The input data have not yet updated the actual MPLT (Memory Production Logging Tool) results into the model. Good match history results with local adjustments in wells are acceptable at this time, but it does not match GOR parameters, since the measured data are not reliable. Regarding the forecast for production, it is recommended to run more cases with the number of wells of 3, 4, and 5 wells to evaluate the base case selection as 6 wells.

Further research should consider the type of enhancement of oil recovery to maximize the oil production in tertiary stage.

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