Application of miscible displacement for Field MTX low permeability formations

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Abstract. Miscible displacement is a very effective method of recovery efficiency improvement. It is widely used in the world, but this technology is not widely used in Russia. For this reason, it is necessary to study global experience and physical aspects of this EOR method. The most important factors and limitations of miscible displacement application from the geological point of view (heterogeneity) and from the physical point of view (properties of injected fluids and reservoir fluids) should be determined. The results of this analysis should be tested on the low permeability reservoir of field MTX with analytical, proxy calculation and simulation methods.

1. Field description
The geological cross section of Field MTX consists of alternating sand and shale layers confined to the Mesozoic-Cenozoic deposits. Field MTX has 9 productive layers that were formed in the same depositional environment. The oil-bearing zones are represented by sand lenses of a varying size and shape (figure 1). The main interest in the current study is applying a gas injection technology to the three upper layers (B6-21, B6-3, B6-31) where STOIIP equals 51 mln tons.

![Cross section](image)

Figure 1. Cross section

These three layers of Field MTX have similar reservoir characteristics and fluid properties (table 1).
### Table 1. Reservoir characteristics

| Parameters                                      | Value                           |
|------------------------------------------------|---------------------------------|
| Depth, m                                        | -3,100                          |
| Trap type layer – arch, lithologically screened |                                 |
| Oil-bearing area, m²*10³                         | 133,145                         |
| Thickness of effective oil-bearing formation, m | 10                              |
| Porosity, %                                     | 16                              |
| Permeability, mD                                | 20                              |
| Oil saturation, %                               | 58                              |
| OWC level, m                                    | No                              |
| Reservoir temperature, °C                       | 100                             |
| Reservoir pressure, MPa                         | 32.7                            |
| Oil viscosity (at reservoir conditions), cp      | 0.28                            |
| Oil density (at standard condition), tons/m³    | 0.834                           |
| Oil formation volume factor                     | 1.491                           |
| Bubble point pressure, MPa                      | 21.9                            |
| Gas – oil ratio, m/ton                          | 200                             |

According to the accepted oil classification, the oil is very light, has a low sulfur, tar and paraffin content. Field MTX is considered "very complicated" from the geological point of view. All these three layers have a common development strategy represented by:
- Seven spot pattern (500 meters between the wells)
- A pattern with horizontal wells with multi-stage hydraulic fracturing (6 stages for production wells and 3 stages for injection wells). The length of the horizontal part of the well equals 1,000 meters.

2. **Screening criteria**

Table 2 was constructed on the basis of information analysis and field experience [10].

### Table 2. Screening criteria for miscible and immiscible gas injection

| Technology/ Factors | Formation factor | Permeability, mD | Heterogeneity | Reservoir and injected fluid composition and reservoir conditions | Density, kg/m³ | Viscosity, cp |
|---------------------|------------------|------------------|--------------|------------------------------------------------------------------|----------------|--------------|
| Miscible displacement | Hydrocarbon      | 0.1 – 5,000      | N/A          | A on the left side of critical tie line                           | 749 - 914      | 0.04 – 18,000 |
| CO₂                 | S & C            | 1.5 – 4,500      | N/A          | A on the opposite or the right side of the critical tie line      | 800 - 920      | 0-35         |
| Nitrogen            | S & C            | 0.2 – 35         | N/A          | A                                                                  | 761 - 848      |              |
| WAG                 | S                | 13 – 1,000       | N/A          | A                                                                  | 828 - 859      |              |
| Immiscible displacement | Hydrocarbon     | 40 – 1,000       | A            | N/A                                                               | 767 - 914      | 0.25-4       |
| CO₂                 | S & C            | 30 – 1,000       | A            | N/A                                                               | 848 - 991      | 0.6 – 592    |
| Nitrogen            | S                | 3 – 2,800        | A            | N/A                                                               | 761 - 957      | 0 – 18,000   |
Thus, the reservoir characteristics are appropriate for all types of miscible displacement and for immiscible displacement with nitrogen. Also, there are several criteria for the reservoir fluid, including the range of densities and viscosities at which these technologies can be applied. The reservoir oil of Field MTX meets these criteria for all types of gas injection, except CO₂ immiscible displacement. It should be noted that there is no available sources of nitrogen and carbon dioxide near Field MTX. Thus, only miscible gas injection with hydrocarbon gas and miscible WAG injection with hydrocarbon gas is available for development and will be further considered. Two more conditions for the application of these technologies were considered by [6]: reservoir pressure should be higher than 20 MPa (the reservoir pressure of Field MTX equals 32.7 MPa) and oil density – smaller than 0.991 tons per m³. The Field MTX characteristics meet both of these conditions. Thus, miscible gas injection can be used for Field MTX.

3. PVT modeling

The PVT modeling of the reservoir fluid was provided with the help of the Schlumberger PVTi software. The reservoir oil composition is presented in table 3.

| Component       | At standard conditions | Oil at reservoir conditions |
|-----------------|------------------------|-----------------------------|
|                 | gas        | oil     | gas    | oil    |
| Carbon dioxide  | 0.6        | 0.006   | 0.35   |
| Nitrogen + other| 0.36       | 0       | 0.21   |
| C1              | 56.11      | 0.065   | 32.47  |
| C2              | 15.73      | 0.42    | 9.27   |
| C3              | 12.72      | 1.69    | 8.07   |
| iC4             | 2.86       | 1.07    | 2.10   |
| nC4             | 5.14       | 2.92    | 4.20   |
| iC5             | 1.53       | 2.05    | 1.75   |
| nC5             | 1.77       | 3.15    | 2.35   |
| C6              | 3.179      | 1.07    | 2.29   |
| C7+             | 0.00       | 87.57   | 36.94  |
| MW of reservoir oil | 82       |          |
| MW of C7+       | 166.87     |          |

Three parametric Peng – Robinson EOS were used to match the model with the real PVT data. The matching process was provided to achieve a convergence between the real and calculated properties of the fluid (GOR, bubble point pressure, oil formation volume factor and viscosity) by the varying parameters of the C7+ fraction (it has higher uncertainty).

4. Minimum miscibility pressure
Gas miscibility grows as pressure increases. Thus, the recovery factor should increase too. It actually occurs, but there is a pressure above which the further pressure increase only entails the minimum increase in the oil recovery. The pressure at which the oil recovery aligned is the minimum miscibility pressure. There are various impurities that can modify the minimum miscibility pressure. Methane and nitrogen increase the minimum miscibility pressure, whereas H2S decreases it.

The ability of impurities to increase or decrease the minimum miscibility pressure depends on whether there is an increased dissolving ability of the gas. The dissolving ability is improved (the minimum miscibility pressure is decreased), if the gas is diluted with an impurity, critical temperature of which exceeds the critical temperature of the gas. The dissolving ability deteriorates (the minimum miscibility pressure increases), if an impurity has a critical temperature lower than the critical temperature of the gas.

There are a lot of equations trough which minimum miscibility pressure can be determined [3]:

For pure and impure CO2:
- Orr and Silva
- Extrapolated Vapor Pressure (EVP) Method
- Yelling and Metcalfe
- Alston et al
- National Petroleum Council (NPC)
- Enick-Holder-Morsi
- Croquist

For lean gas and nitrogen:
- Firoozabadi and Aziz
- Hudgins-Liave-Chung
- Glaso

In the current work, the minimum miscibility pressure was estimated through four different methods that gave similar results.

Input data for calculation:
- reservoir oil composition presented in Table 3.
- only associated petroleum gas used for miscible displacement (Table 3) that contains 56% of the C1 fraction.
- oil at reservoir conditions is undersaturated (Pres = 32.7 MPa, Pb = 21.9 MPa, GOR = 200 m³/ton)
- **Firoozabadi and Aziz** [2]

\[
MMP = 9.433 - 188(10^3)F + 1,430(10^2)F^2 = 4,378.57 \text{ psi} = 29.8 \text{ MPa}
\] (1)

where

\[
F = \frac{I}{M_{C7+}}\frac{1}{T-460^{0.25}} = 0.03769
\] (2)

\[
I = x_{C2-C5} + x_{CO2} + x_{H2S} = 23.99\%
\] (3)

**Hudgins-Liave-Chung** [2]

\[
MMP = 5,568e^{R1} + 3,641e^{R2} = 3,958 \text{ psi} = 27 \text{ MPa}
\] (4)

where

\[
R1 = \frac{-792.06x_{C2-C5}}{M_{C7+}T^{0.25}} = -0.345066
\] (5)

\[
R2 = \frac{-2158(10^6)x_{C1}}{M_{C7+}T^{0.25}} = -5.5347
\] (6)

where T – temperature (212 °F); C1 – mole fraction of methane; \(x_{C2-C5}\) – sum of the fraction of \(C_2 - C_5\) in the oil phase.
- **Glaso for condensing-vaporizing drive** [1]
To calculate MMP with injection gas with MC$_2$-C$_6$ = 20, the following equation was used:

\[
MMP = 43.74 - 0.1752M - (32.23 - 0.127M)y_1 + (0.777\times10^{-14}M^{5.258}e^{31980y_1M^{-1.703}})(1.8T - 460) = 32 \text{ MPa}
\] (7)

with

\[
M = \frac{572.7}{S_{C7+}^{5.573}}
\]

where \(T\) – temperature (373.15 K); \(y_1\) – mole fraction of methane in the injection gas; \(M_{C2-C6}\) – sum of the fraction of C$_2$ – C$_6$ in the injection gas.

- **Equation based on Maklavani correlation** [13]

\[
MMP = 43.664 - 4.542\alpha + 0.689\alpha^2 - 0.132\beta = 30.6 \text{ MPa}
\] (9)

with

\[
\alpha = \frac{x_{C2-C6}^{0.4}x_{C1}^{0.1}}{(1.02T+32)^{0.5}M_{C7+}} = 0.211472
\]

\[
\beta = Y_{C2+}^{(1.064+0.00686M_{C7+})} = 91.65134
\]

where \(T\) – temperature (100 °C); \(C_1\) – mole fraction of methane; \(x_{C2-C6}\) – sum of C$_2$ – C$_5$ in the oil phase, %; \(x_{C1}\) – mole percent of methane in the oil, %; \(Y_{C2+}\) – mole percent of C$_2$ in the injected gas, %; MC$_2+$ – molecular weight of C$_2+$ in the injected gas.

All calculations are summarized in Table 4. It should be noted that the difference in MMP determination with different equations is smaller than 10%. Also, all the above calculated MMP values are smaller than the initial reservoir pressure that equals 32.7 MPa.

**Table 4. MMP summary**

| Equation                                      | MMP, MPa |
|-----------------------------------------------|----------|
| Firoozabadi and Aziz                         | 29.8     |
| Hudgins-Liave-Chung                          | 27       |
| Glaso for condensing-vaporizing drive         | 32       |
| Maklavani correlation                        | 30.6     |

The pseudo ternary plot obtained with PVTi simulation shows that miscibility will occur at reservoir conditions (figure 2).
It should be noted that injected gas for miscibility displacement at reservoir conditions should not contain more than 62% of the C$_1$ fraction.

5. Displacement efficiency coefficient

The displacement efficiency coefficient for the B6 layers of the field was obtained from the core data and equals 0.407. Stepanova G.S. provides an equation for the analytical calculation of the displacement efficiency coefficient for miscible gas injection and WAG injection with the maximum inaccuracy being equal to 9%. On the basis of her study [12], analytical calculations were provided.

Firstly, it is necessary to estimate a viscosity ratio between the reservoir fluid and gas in the transition zone.

\[
\mu_{0\,min} = 0.1017 \cdot 10^{-3}F^4 - 0.02417F^3 + 2.1614F^2 - 86.887F - 6.147 \cdot 10^{-3}p^2 - 23.945p - 18.044\frac{Pb}{p} + 1646.39 + C = -43.0424 = 1
\]  
with
\[
C = -0.1243M^2 + 1.454M + 19.6 = -45.4145
\]  
where F – percent of oil volume recovery till 300 °C, (65 %); M – MW of gas; P – reservoir pressure (32.7 MPa); Pb – bubble point pressure.

If \( \mu_{0\,min} \) is lower than zero, it should be equated, because it characterizes the condition of full miscibility. The next step is determining the displacement efficiency coefficient in case of miscible gas injection:

\[
DE_{misc.\,gas\,inj.} = 1.0192 - 0.2706 \cdot 10^{-2}p - 0.1573 \cdot 10^{-2}t + 0.3243 \cdot 10^{-4}k + 0.5464 \cdot 10^{-2}\mu_{0\,min} - 0.6310 \cdot 10^{-3}p\mu_{0\,min} - 0.2054 \cdot 10^{-6}(p\mu_{0\,min})^2 = 0.759
\]  
where P – reservoir pressure (32.7 MPa); t – reservoir temperature (100 °C); k – permeability, (20 mD); \( \mu_{0\,min} \) – viscosity ratio between the reservoir fluid and gas in the transition zone.

And the last step is determining the displacement efficiency coefficient in case of miscible WAG.
\[ DE_{\text{misc. gas inj.}} = 1.3367 + 0.8898 \cdot 10^{-2}p - 0.6998 \cdot 10^{-2}t + 0.5286 \cdot 10^{-4}k + 0.8099 \cdot 10^{-2}\mu_{0\text{ min}} - 0.4438 \cdot 10^{-3}p\mu_{0\text{ min}} - 0.1508 \cdot 10^{-6}(p\mu_{0\text{ min}})^2 - 0.4868 \cdot 10^{-1}\theta = 0.874 \]  

with \( \theta \) – factor that characterizes the type of impact and can vary from 1 to 6 (for miscible WAG with APG, it equals 1). Table 5 reflects calculated displacement efficiency coefficients, the sweeping efficiency coefficient for the 7-spot flood pattern (from the input data) and calculated recovery efficiency for the 7-spot pattern.

### Table 5. Displacement efficiency

| Technology              | Displacement efficiency coefficient | Sweeping efficiency coefficient | RF, % |
|-------------------------|-------------------------------------|--------------------------------|-------|
| Waterflooding           | 0.407                               | 0.789                          | 32.1  |
| Miscible gas injection  | 0.759                               | 0.789                          | 59.9  |
| Miscible WAG            | 0.874                               | 0.789                          | 68.9  |

It should be noted that the highest recovery efficiency is achieved for miscible WAG injection and the lowest level is relevant to waterflooding.

### 6. Development strategy

Layer B6 at Field MTX has the following characteristics:
- Cumulative oil production equals 397*10^3 tons
- Recovery factor – 0.4%
- Current number of appraisal wells – 14
- Current number of exploitation wells – 0
- There are two accepted development strategies: waterflooding with a 7-spot pattern (500 meters between the wells); waterflooding with horizontal wells with multi-stage hydraulic fracturing (6 stages for production wells and 3 stages for injection wells). A fracture with specific parameters allows involving all the 3 layers into development with 1 well (the fracture is somewhat smaller than the interval between the top of the upper layer and the bottom of the lower layer). The length of the horizontal part of the wells equals 1,000 meters.
- Well operation conditions were determined with the following input data: production wells with ESP and BHP = 20 MPa, maximum BHP for injection wells = 50 MPa.

A three-phase black oil model was constructed. This model was converted into the Schlumberger Eclipse – 300 compositional model with the help of the PVT model for the reservoir fluid obtained with the PVTi Schlumberger software. Simulation was carried out for the sector of Field MTX. Different strategies on three different well patterns were assessed (in addition to the patterns adopted by the Oil Company, a 5-spot pattern was considered; it implied similar well density values with the 7-spot pattern). The following strategies were assessed:

- Waterflooding
- Miscible gas injection (restrictions on the injected gas volume with the quantity of APG)
- Miscible gas injection (no restrictions on quantity, the lacking volume of gas will be imported)
- WAG with alternation performed every 6 months
- WAG with alternation performed every year
- WAG with alternation performed every 2 years

The number of wells for each development strategy was as follows:
- The 7-spot pattern includes 32 production wells and 20 injection wells
- The case with horizontal wells includes 8 production wells and 6 injection wells
- The 5-spot pattern includes 30 production wells and 25 injection wells

Waterflooding was the first strategy to be considered (Figure 3).
As one can see from the graph, the highest recovery factor is achieved with horizontal wells and equals 0.32. The intermediate result is achieved with a 7-spot pattern and equals 0.312 and almost the same result is achieved with a 5-spot pattern and equals 0.31. The highest recovery efficiency with horizontal wells was achieved due to the higher drainage area of the horizontal wells and better pressure support. The maximum economic efficiency (NPV) is also relevant to horizontal wells due to the 75% smaller number of wells (Table 6). The 5-spot pattern takes the second place in terms of economic efficiency due to the better pressure support vs. the 7-spot pattern and thus leads to a higher production rate.

The second strategy was reinjection of APG separated from oil (figure 4)

It should be noted that the recovery factor reached with this strategy is no more than 13.5% due to the poor pressure support, as the amount of associated petroleum gas is too small for good pressure maintenance (for all the patterns, NPV is negative). Thus, the next strategy to be considered was also miscible gas injection (figure 5), but without restrictions on the quantity of gas with the volume of APG separated from oil (the lacking volume of gas will be imported from another field).
This development strategy shows a better result for all types of patterns than the previous one. Also, there are recovery factors being higher than those in case of waterflooding. The maximum recovery factor is achieved for the 7-spot pattern and equals 56.5%. The lowest recovery factor equals 52.7% for the 5-spot pattern. The highest NPV is achieved with horizontal wells due to the small number of wells. The recovery factor in this case equals 53.7%, which is smaller vs. the 7-spot pattern due to a faster gas breakthrough from injectors to producers. The lowest economic efficiency is relevant to the 5-spot pattern due to lower production rates at the early stage of field development (smaller number of producers vs. the 7-spot pattern, lower productivity index and higher quality of producers (higher CAPEX) in comparison with the horizontal wells pattern). Pressure support in all these cases is good and the average reservoir pressure does not falls below 300 bars.

The main benefits of WAG injection are as follows: better sweep control, mobility control over water and gas phases and thus displacement efficiency improvement. There is one more benefit for Field MTX: there is a less acute need for imported gas because Field MTX can be divided into several sectors with different injected agents at the same time (i.e. gas is injected in some sectors while water is injected in others). Besides, one of the main drawbacks is a more complex infrastructure in comparison with the previous strategies. The next stage was the assessment of miscible WAG injection with sensitivity to the time periods of agent injection. The first one was alternating agents every 6 months (figure 6).
The WAG injection strategy shows an increase in recovery efficiency in comparison with the miscible gas injection strategies. The highest recovery is achieved with a 7-spot pattern and equals 67%. The highest NPV is relevant to horizontal wells with a recovery factor being equal to 64.6%. The worst case in terms of NPV and recovery efficiency was the 5-spot pattern. The next strategy was alternating agents every year (figure 7).

A trend being similar to the alternation of agents every 6 months can be determined for the WAG injection with alternation performed every year. However, a small decrease in recovery efficiency (less than 1%) is present for all the patterns. The trend persists for WAG injection with alternation to be performed every 2 years, but the decrease in the recovery factor is higher (figure 8) (more than 2% in comparison with alternation occurring every 6 months).
Simulation and economic data are summarized in Table 6. It can be seen that the highest recovery factor is achieved with a 7-spot pattern and WAG injection with alternation performed every 6 months and equals 67%. The highest NPV and NPVI are achieved with horizontal wells and WAG injection with alternation performed every year and equal 8,461.3 million rubles and 6.7, respectively. The highest IRR is achieved in horizontal wells and miscible gas injection (without restrictions on the quantity of injected gas) and equals 198%.

The pattern with horizontal wells and WAG injection (alternated every year) was recommended for development, as it has the highest NPV (8,461.3 mln rubles) and a high recovery factor (64.8%). The scenario with a 7-spot pattern and WAG injection (alternated every 6 months) has a 2-percent higher recovery factor, but the NPV is smaller by 30%.

**Figure 8.** WAG injection (alternated every 2 years) strategy

| Development strategy                  | Well patterns   | RF,% | NPV, mln rub | IRR  | NPVI |
|--------------------------------------|-----------------|------|--------------|------|------|
| Waterflooding                        | Horizontal wells| 32   | 1,282.5      | 0.26 | 1.3  |
|                                      | 7-spot          | 31.2 | -2,521.1     | -    | -    |
|                                      | 5-spot          | 31   | -2,118.1     | -    | -    |
| Miscible gas injection (reinjection of APG separated from oil) | Horizontal wells | 13.5 | -512.5       | -    | -    |
|                                      | 7-spot          | 12.9 | -3,729.3     | -    | -    |
|                                      | 5-spot          | 12.3 | -4,040.5     | -    | -    |
| Gas injection (gas import)           | Horizontal wells| 53.7 | 7,851.2      | 1.9881 | 6.2  |
|                                      | 7-spot          | 56.5 | 6,272.4      | 0.9938 | 3.2  |
|                                      | 5-spot          | 52.7 | 5,038.1      | 0.8141 | 2.4  |
| WAG (alternated every 6 months)      | Horizontal wells| 64.6 | 8,303.4      | 1.6633 | 6.5  |
|                                      | 7-spot          | 67   | 5,952        | 0.7282 | 2.6  |
|                                      | 5-spot          | 64.2 | 5,491        | 0.6761 | 2.3  |
| WAG (alternated every year)          | Horizontal wells| 64.8 | 8,461.3      | 1.562 | 6.7  |
|                                      | 7-spot          | 66.2 | 6,041.1      | 0.6689 | 2.1  |
|                                      | Horizontal wells| 64.5 | 5,533.8      | 0.6184 | 1.9  |
WAG (alternated every 2 years)

| Method          | Oil Rate | Gas Rate | Water Rate | Pressure |
|-----------------|----------|----------|------------|----------|
| 7-spot          | 63.2     | 7,967.7  | 1.538      | 6.3      |
| 5-spot          | 64.8     | 6,185.2  | 0.7078     | 2.2      |
| Horizontal wells| 63.2     | 5,458.6  | 0.6017     | 1.9      |

As one can see from Tables 6 and 5, the analytical calculations show better (but similar to simulation) results in terms of recovery efficiency with the maximum deviation equal to 2% (relative).

The main technical parameters of the recommended development plan are presented in Figures 9-11. Its dynamics shows that there was a slight decrease in reservoir pressure (50 bars) during the early stages and it was subsequently compensated for. The periods of water injection and gas injection are distinguishable in the graphs, and the impact of these periods on the water cut and GOR are distinguishable too. Cumulative oil production equals 4.5 mln tons.

Figure 9. Production rates and average reservoir pressure

Figure 10. Injection and production cumulative
Assumptions and input data used for economics calculations:
- Base year: 2014
- Inflation and exchange rate forecast provided by the Ministry of Economic Development and Trade
- Oil price in the domestic market: 12,500 rubles per ton
- Discount factor: 10%
- Unit of production depreciation scheme
- Percentage of oil that can be exported: 30%
- Wells dropping out of production due to the economic limit: water cut being higher than 98%, oil production rate being lower than 1 ton/day, GOR being higher than 1,000 m³/m³

The calculation results are presented in figure 12.
At the end of development, NPV equals 8,461.3 mln rub, IRR equals 156.3%, NPVI equals 6.74, total CAPEX [@2014] equals 3,001.3 mln rub, total OPEX [@2014] equals 10,166 mln rub, total taxes [@2014] equals 55,182 mln rub.

8. Proxy model
In addition, the computational accuracy and practical applicability of the 2D areal model for Field MTX was assessed. Calculating a 2D model is significantly less time-consuming vs. a full-scale 3D model. The results obtained (Table 7) show that the calculations for the 2D areal model are very inaccurate in comparison with the full-scale 3D model with deviations ranging from 2.9% to 46.2%. This is due to the fact that the 2D areal model does not account for vertical heterogeneity, thus all recovery factors which were obtained with the 2D model have excessively high values. Thus, the 2D areal model cannot be applied to accelerate Field MTX simulation.

Table 7. Comparison of 3D and 2D simulation results

| Development strategy                | Well patterns           | RF 3D, % | RF proxy, % | Deviation, % |
|------------------------------------|-------------------------|----------|-------------|--------------|
| Waterflooding                      | Horizontal wells        | 32       | 44          | 37.5         |
|                                    | 7-spot                  | 31.2     | 45.6        | 46.2         |
|                                    | 5-spot                  | 31       | 44.6        | 43.9         |
| Miscible gas injection             | Horizontal wells        | 13.5     | 13.9        | 2.9          |
| (reinjection of APG separated from oil) | 7-spot                  | 12.9     | 14          | 8.5          |
|                                    | 5-spot                  | 12.3     | 13.2        | 7.3          |
| Gas injection (gas import)         | Horizontal wells        | 53.7     | 69.5        | 29.4         |
|                                    | 7-spot                  | 56.5     | 71.3        | 29.2         |
|                                    | 5-spot                  | 52.7     | 75.1        | 42.5         |
| WAG (alternated every 6 months)    | Horizontal wells        | 64.6     | 83.4        | 29.1         |
|                                    | 7-spot                  | 67       | 84.5        | 26.1         |
|                                    | 5-spot                  | 64.2     | 85.3        | 32.9         |
| WAG (alternated every year)        | Horizontal wells        | 64.8     | 83          | 28.1         |
|                                    | 7-spot                  | 66.2     | 85.5        | 29.2         |
|                                    | 5-spot                  | 64.5     | 84.6        | 31.2         |
| WAG (alternated every 2 years)     | Horizontal wells        | 63.2     | 82.5        | 30.5         |
|                                    | 7-spot                  | 64.8     | 80          | 23.5         |
|                                    | 5-spot                  | 63.2     | 85.9        | 35.9         |

9. Conclusion
The results of this study show the benefits of miscible displacement and miscible WAG injection over the waterflooding strategy. These methods allow producing more oil from reservoirs than conventional waterflooding. An increase in recovery efficiency can be identified by comparing the waterflooding strategy with miscible gas injection and water alternating miscible gas injection. The highest recovery factor can be achieved with miscible WAG injection (67%), an intermediate result is relevant to the miscible gas injection strategy where the recovery factor equals 56.5% and the worst result was shown by the waterflooding strategy (32%). It was determined that the efficiency of miscible WAG was better than miscible gas displacement. Also, there is an improvement in the economic efficiency of the project with NPV of 1.2 billion rubles for waterflooding up to 8.4 billion rubles for miscible WAG.

The comparison of the analytical and simulation results showed their convergence, moreover, the analytical calculations showed a higher recovery factor vs. simulation by 2%.

A proxy (2D areal) model was also considered. It showed significant differences in the results in comparison with the full-scale 3D model due to the high vertical heterogeneity of Field MTX. Thus, it was established that proxy modeling has no practical applicability in Field MTX simulation.
The sensitivity analysis of miscible WAG displacement to the periods of agent alternation was performed to show that the optimal time of agent injection equals one year (the most cost effective option).

Despite the fact that WAG injection and miscible gas injection are hard to implement and require expensive equipment for pumping gas, the economic calculations show that the additional profit covers the additional costs of capital investments. Thus, an optimal development strategy was chosen. It is the pattern with horizontal wells and miscible WAG injection with agent alteration to be performed every year, because it has the highest NPV (8.4 billion rubles) and a high recovery factor (64.8%).

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