Technological features of pumping water into high-viscosity oil injection wells with the bottom hole pump

Sh G Mingulov¹, I Sh Mingulov¹ and V V Mukhametshin²

¹ Ufa State Petroleum Technological University, Branch of the University in the City of Oktyabrsky, 54a, Devonskaya St., Oktyabrsky, Republic of Bashkortostan, 452607, Russian Federation
² Ufa State Petroleum Technological University, 1, Kosmonavtov st., Ufa, Republic of Bashkortostan, 450062, Russian Federation

E-mail: vv@of.ugntu.ru

Abstract. The authors laid bare a correlation between the proportion of mechanical contaminations and oil products in discharge waters and the average oil viscosity in the field. Film thickness depends on the oil viscosity. More viscous oil forms thicker and heavier films on the surface of suspended solids. The use of electrical centrifugal pumps for fossil water injection into the well allows using the heat produced by the pump to warm the water. Standard measurement instruments show that the change of injected water temperature at the head of the well pump-over unit is between 1.1 and 8.4 °С. The average temperature increase is 3.6 °С.

1. Introduction

One of the ways to improve the efficiency of high-viscosity oil pool development is maintaining the bottom-hole pressure by injecting water into the bed [1–5]. However, the use of this development method under specific geological and field conditions requires checking the specifics of the process [6–10].

The prepared bottom water injected into the bed may contain some amounts of suspended particles consisting of both the oil phase and mineral substances [11, 12]. Oil film covers solid particles thus reducing the overall density of the suspension and complicating its settling-put in the preparation units. This is largely due to the fact that the hydrocarbon phase adhesion to solid surfaces significantly exceeds the water phase adhesion.

Solids that enter the well-bore from the bed get covered in oil film of a certain thickness as they move. Its thickness depends primarily on the physical and chemical properties of the oil phase.

Since the density of solid particles covered in the film depends on the phase components, i.e. The oil products and mineral substances, we analyzed the correlations between phase proportions and produced oil viscosity.

2. Materials and Methods

We analyzed the impact of oil product and mechanical contaminations in waters discharged from medium-viscosity oil at several water discharge units of Tuymazaneft NGDU, Chekmagushneft, and Krasnokholmskneft.
3. Results and Discussion

We determined that film thickness (oil volume in suspension) depends on the oil viscosity. More viscous oil forms thicker and heavier films on the surface of suspended solids.

Figure 1 shows the correlation between the proportion of oil products and suspended solids in discharge waters and the average oil viscosity in the field well groups. The correlation can be described with the $\frac{V_o}{V_s} = f(\mu)$ function where $V_o$ is the oil product concentration in discharge waters in mg/l, $V_s$ is the concentration of solids in discharge waters in mg/l; $\mu$ is the average viscosity in mPas.

![Figure 1. The correlation between the proportion of oil and water in discharge waters and the average oil viscosity in the field well group.](image)

With high confidence, $R^2 = 0.78$ and this function is described by the following equation: $y = 0.0253x$.

Therefore, the surface of solids gets covered in the oil phase whose thickness depends on the viscosity of the produced oil. The content of oil products in discharge waters from high-viscosity oil fields increases along with the thickness of the film covering suspended solids. The quality of oil and discharge water preparation in preparation units and settling pits.

The presence of the film on solids significantly increases the clogging rate of the pore volume in the bed bottom hole area and reduces the injection capacity of the well. The coagulation of solid particles with the oil film and the increase of the clogging substance due to the presence of such film increases the contamination rates of the bottom-hole area (BHA) of the injection well and the pore volume clogging.

Thus, one of the ways to improve the efficiency of injection capacity recovery and BHA treatment intervals is the heating of injected water to reduce the viscosity of the oil film on the surface of the solids [13]. This allows reducing the volume of the colmatant by the dissolution of paraffinic hydrocarbons and a partial oil filtration in the pore volume.

There is a well pump-over (WPO) technology that uses the heat of the fluid as it passes through the downhole motor and the step decks. The dissipation of energy in the fluid fed to the downhole motor is achieved due to the stator winding resistance and the motor magnetic resistance. Besides, fluid heating is achieved through friction in the main bearings of impellers [14].

Figure 2 shows the basic diagram for WPO operation in an injection well when injecting the water from the upper water bed into the pay bed.
Figure 2. Water injection diagram for well 104 at Yubileynoye field

The electric centrifugal pump unit (ECPU) is tripped on the flow column into the well in the upside-down position. The water is injected into the bed through a pipe that passes the packer. At the pump head, there is a telemetry unit with a flowmeter installed that transmits information to the ground surface via the power cable of the electric motor. This information includes the flowrate and temperature of the water injected.

The fluid passes between the oil-well tubing and the extracting column, enters the pump suction, and is then fed into the pay bed via the packer pipe.

The water is injected from the upper water bed, the Sserp bed, that has the highest productivity factor, a broad external boundary, and a decent thickness of the water layer. Before hoisting down the pump, a packer is installed in the well. The packer has a pipe with a left-hand thread on the upper end. Besides, the upper end of the pipe features a cylinder that encapsulates the pump nipple. The ECPU is lowered as close to the pay bed as possible to prevent the heat leaking from the fluid pump to the borehole environment.

The goal of BHA heating is to measure the temperature change value at the WPO head and the impact of water heating on the operational parameters of the well.

To solve this problem, we researched injection well 104 at the Yubileynoye field of Tuymayaneft NGDU. The commercial oil beds in Yubileynoye include C1rd+C1bb of Bobrikovian-Radaevian horizon, CII benches of the Tournai stage, and D3fm2 packs of the Famennian stage. The water is injected in well 104 From Sserp bed to Dfams bed using the well pump-over unit.

According to the readings from the telemetry sensors installed on the well pump over (WPO) units in the operating wells of Mustafinskoye, Usen-Ivanovskoye, Solontsovskoye, and Abdulovskoye fields, the temperature variation interval is between 1.1 and 8.4°C.

Table 1 shows the data on the changes in water temperature at the well pump-over heads. The experiments showed that the average temperature increase is 36°C.
Table 1. Telemetry sensor readings at well pump-over units

| Well No. | Field               | Temperature increase at the WPO head in °C |
|---------|---------------------|-------------------------------------------|
| 127     | Mustafinskoye       | 1.1                                       |
| 10MUF   | Mustafinskoye       | 8.4                                       |
| 1784    | Usen-Ivanovskoye    | 2.3                                       |
| 37YCT   | Solontsovskoye      | 5.0                                       |
| 201PTM  | Abdulovskoye        | 1.5                                       |

It is especially relevant to assess the impact of temperature increase on the operation mode of the well equipped with a pump-over unit. To do that, we analyzed the dynamics of the operational characteristics of wells where water is injected from the Sserp bed wells.

To compare the operational characteristics, we selected five injection wells in the Ardatovskoye field where the Dfams bed was injected with water from the Sserp bed intake wells. Table 2 shows the geological and physical characteristics of the injection facility of well 104 at the Yubileynoye field and 5 wells in the Ardatovskoye field. We can see that the field development targets compared have similar geological and physical parameters.

Table 2. Geological and physical parameters of the Dfams bed of the mid-Famennian sub-stage at Yubileynoye and Ardatovskoye fields.

| Parameter                                                                 | Development targets                   |
|---------------------------------------------------------------------------|---------------------------------------|
|                                                                          | Yubileynoye field | Ardatovskoye field | Mid-Famennian sub-stage Dfams |
| Average total thickness in m                                             | 13.5 | 12.1 |
| Average effective oil height in m                                        | 12.8 | 7.1 |
| Porosity factor                                                          | 0.03 | 0.04 |
| Oil saturation factor of the bed, in decimal quantities                  | 0.90 | 0.90 |
| Permeability, um²                                                        | 0.010 | 0.011 |
| Sand fraction in decimal quantities(μl)                                   | 0.96 | 0.85 |
| Stratification                                                           | 1.6 | 2.6 |
| Initial bottom-hole temperature in °C                                     | 25 | |
| Initial bottom-hole pressure in MPa                                      | 13.4 | 13.4 |
| Oil viscosity under reservoir conditions in MPa s                         | 72.38 | 36.4 |
| Oil density under reservoir conditions in t/m³                            | 0.918 | 0.897 |
| Oil density under surface conditions in t/m³                             | 0.924 | 0.908 |
| Formation volume factor in decimal quantities                            | 1.010 | 1.032 |
| Sulfur content in oil in %                                               | 4.0 | 3.2 |
| Paraffin content in oil in %                                             | 4.3 | 4.0 |
| Bubble point pressure in MPa                                             | 3.0 | 5.2 |
| Gas factor in m³/t                                                       | 4.2 | 12.3 |

Figure 3 shows the dynamics of operational parameters within the first year of operation for well 104 and the average for the 5 injection wells of the Ardatovskoye field where water is injected from intake wells. The changes in the injection capacity of well 104 can be described by the $Q_r = f(t)$ function. The injection capacity drop rate is described by the exponential equation $y = 89.268e^{-0.024t}$ with the accuracy value of $R^2 = 0.8709$. The average injection capacity drop rate for the 5 injection wells of the Ardatovskoye field where water is injected from intake wells can be described by the exponential equation $y = 84.644e^{-0.045t}$ with the accuracy value of $R^2 = 0.9707$. 
After about 12 months, the drop rate of the WPO well is lower than that of the water intake wells. The injection capacity drop of well 104 amounted to about 20 m$^3$/day, while for other, non-WPO wells, the average drop rate amounted to 30 m$^3$/day. The injection pressure in the wells in question was not considered because it varied insignificantly and within the measurement error. The use of ECPU allows injecting water under high pressure, which is sometimes impossible to maintain in the water injection system pipelines.

It happens when the increased injection pressure is only necessary for specific wells or the injection is performed at the remote parts of the field that lack the preparation infrastructure and produced water transportation.

### 4. Conclusion

1. The authors laid bare a correlation between the proportion of mechanical contaminations and oil products in discharge waters and the average oil viscosity in the field. Film thickness depends on the oil viscosity. More viscous oil forms thicker and heavier films on the surface of suspended solids.

2. The use of ECPU for fossil water injection into the well allows using the heat produced by the pump to warm the water.

3. Standard measurement instruments show that the change of injected water temperature at the head of the WPO unit is between 1.1 and 8.4 °C. The average temperature increase is 3.6 °C.

4. After about 12 months, the injection capacity drop rate of the WPO well is lower than that of the water intake wells. The injection capacity drop at a WPO well amounted to about 20 m$^3$/day, while for other, non-WPO wells, the average drop rate amounted to 30 m$^3$/day.

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