

Research Article

Results of Introducing Innovative Thermal Mining Technologies at Yaregskoye Oilfield

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Abstract

Presented in this paper are results of the introduction of a modernized single-horizon system of development with heat-insulated pipes at the inclined block "Северный" ("North") Oil Mine № 2 on the Substation Control «SC-2 bis» (ОПУ-2бис) and Substation Control «SC-3 bis» (ОПУ-2бис) pilot plots of Yaregskoye Oilfield.

In plots SC-2 bis and SC-3 bis, thermometry is systematically carried on the control wells to determine the temperature distribution in the reservoir, as well as the rational distribution of steam injection in the developed plot. A method for determining the effectiveness of injection wells on pilot plots was developed by staff at Ukhta State Technical University. In line with the method, studies which helped to determine the acceleration of underground injection wells necessary for calculating the volume of steam injection at each pilot plot were carried out.

Also, regular sampling of water extracted from wells for determining the presence of chlorides is carried out. Based on the analysis of these samples, wells in which have inflows of reservoir water from the aquifer are detected and develop measures to isolate them are then developed.

Keywords: Yaregskoye oilfield; Viscosity; Energy; Oil recovery

Introduction

Yaregskoye oilfield is located in Komi Republic 25 km south-west from the city of Ukhta which forms part of the Timan-Pechora oil and



gas province. Crude Oil from Yaregskoye oilfield is heavy and has a high viscosity (oil density - 945 kg/m³, oil viscosity at reservoir conditions - 16,000 mPa·s). The oilfield lies below ground level at a depth of 140 - 200 m. The geological reserves of the oilfield are 300 million tones [1].

Yaregskoye oilfield (Figure 1) consists of the following plots: Yaregskoye, Lyaelskoye and Vezhavozhskoye. Currently, only Yaregskoye plot is under industrial development while at the Lyaelskoye plot industrial pilot projects are being carried out for testing SAGD technology.

Yaregskoye oilfield was discovered in 1932. Since 1935 experimental development of it has been going on from the surface of vertical wells in a triangular grid on 2 plots of land with areas of 284,000 and 150,000 M², respectively. Experimental works continued until 1945, and for 10 years oil recovery didn't exceed 2%.

Mining method for the development of the Yaregskoye area began in late 1939. A dense mesh of polygon-penetrating production wells were drilled out of the fields drifts systems running along the cap of the production formation to reach the deposit. Oil production was possible due to the internal energy of the reservoir, as well as by the energy of the dissolved gas. In 1954, the technology of steadily inclined wells was also tested and used for drilling a grid of polygon-penetrating wells

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Page 2 of 6

from the galleries located at the base of the formation in the area. The mining method's advantage was the close proximity of the oil reservoir which allowed the maximum use of its internal energy, but the final oil recovery using both technologies did not exceed 4% to 6%.

In 1972, thermal mining technology development started. Though innovative at the time, it is still unique till date. With this technology, steam is injected into the reservoir to heat the oil and then the heated oil with lower viscosity flows into the production wells drilled from the drilling galleries at the reservoir base. During that time several systems



Figure 2: Single horizon system of development.



Figure 3: Double-horizon system of development.



Figure 4: Underground-surface system of development

of thermal mining development were tested and implemented. Using all the systems the area was developed in blocks, with each block having an inclination across the drilling gallery to the base of the formation from where the entire mesh of drilled polygon-penetrating production wells originates. The basic difference between the development systems is different arrangement of the injection wells. One of the first thermal mining technologies tested at the Yaregskoye oilfield was the singlehorizon system (Figure 2). Its feature is that the production and injection wells can be drilled from a single drilling gallery, located at the base of the production formation. The wells are arranged in pairs, one of them in the upper portion of the formation through which steam is injected, and another at the bottom, through which heated oil flows.

The results of the application of this system proved its higher efficiency, but further use had to be abandoned. One of the key reasons for the refusal of the widespread introduction of steam was its breakthrough into the drilling gallery and that does not allow for the creation a safe working environment in the petroleum mine. The presence of two double-horizon systems on the field drifts passing over the site being developed allows for the drilling of injection wells using the system of polygon-penetration (Figure 3). The advantage of this system is a uniform coverage of the reservoir area by steam at a low injection pressure. This system was one of the most effective, but it was abandoned because of the high capital costs of tunneling field drifts.

To date, the main technology used on an industrial scale in the Yaregskoye oilfield is the underground-surface system (Figure 4). This system involves the drilling of injection wells from the surface. Its implementation allowed for the increase in the pace of development of the oilfield as well as raises the level of production at the mine, but the underground and surface system also is not without drawbacks. Its main drawback - the injection of steam into the reservoir under high pressure (10-12 atm.), which does not put into consideration the geological and physical characteristics of the deposit (high natural fracture). Included amongst the significant disadvantages is the high capital and operating costs for the drilling and maintenance of surface wells.

Given the experience of developing Yaregskoye oilfield and large supplies of heavy oil, the actual problem is to improve the systems of thermal mining development to increase oil recovery rates and reduce steam-oil relationship.

Material and Methods

The employees of Ukhta State Technical University developed a more effective technology for the development of Yaregskoye deposits that allows for an increase in the rate of steam injection and oil



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recovery. A single-horizon system was adopted at the beginning as the technology is the best taking into account the geological features of deposits and reduced capital costs. Improvement to the technology was made possible due to new constructions of underground wells (Figure 5). To exclude steam leakages into the production gallery, production and injection wells are cased and cemented 50 meters from the top of specialized heat-insulated pipes.

Optimal parameters of the wells, their location and the length of the perforation were selected based on numerical simulation. According to the results of modeling, the optimal length of the perforation of injection wells was 2/5 the length of the holes, 3/5 the length for the top row of wells and the entire length of the lower production wells. Also, the project includes the development of control wells which were cased and cemented all through their entire lengths.

In 2010, "Lukoil-Komi" decided to conduct pilot projects for

testing the technology. On the recommendation of NSHU "Yareganeft" for testing the upgraded single-horizon development system, the inclination "Северный"/"North" (Figure 6) oil mine № 2 was chosen. It consists of 2 plots of Substation Control (SC)–2 bis/(ОПУ-2 бис) and Substation Control (SC)–3 bis/(ОПУ-3 бис). The plot areas are 4.7 hectares and 4.3 hectares respectively.

It should be noted that organization of control of the trajectory of wells in mine conditions is complicated by the following reasons: inability to use standard methods due to fire and explosion hazards and high costs of well logging using modern telemetry systems in explosionproof instances (Figure 7).

In order to adequately monitor the trajectory condition of horizontal wells, a simple method for determining the zenith angle of wells during the process of drilling was proposed by Ukhta State Technical University (V.F. Buslaev) in 2006 which involves measuring the hydrostatic pressure of the liquid column in the wellbore using a manometer. This method is called gauge pressure method. Control of zenith angle using gauge pressure (manometer) method is carried out in most of the wells. The disadvantages of using gauge pressure (manometer) method include inability to accurately determining the azimuth of the trajectory and lack of information about the behaviour of the trajectory of wells after reaching the highest point.

Given the nature of the work accomplished, the project involved a directional survey of wells in the pilot area using modern inclinometers which aid in determining the position of the wells trajectories not only vertically but also in a horizontal plane i.e., azimuth. Table 1 shows the number and scope of well testing using an inclinometer.

As the table shows, 43.6% of well stock on plot SC-3 bis was tested, including 86% of injection and 25% of producing wells. Figure 8 shows a comparison of the design and trajectories studied using inclinometer in plot SC-3 bis. The solid lines show the trajectory of the tested wells using an inclinometer.

As can be seen from Figure 8 actual well trajectories deviate significantly from the design trajectories. Figures 9-10 show dynamics of technological parameters during development on plot SC-3 bis. Development of the pilot area began in October 2012 (Figures 9 and 10).

Current developmental indicators of plot SC-3 based bis site dates analysis was done are as follows: average daily oil production -45-50 t/ day, daily average of steam injection -45.2 tons/day, the current steamoil ratio -1.0 t/t, average temperature of the produced fluid -85° C to 89°C. In just 37 months (as at 01.12.15) 113,6 thousand tones of steam was pumped into the reservoir and at its expense 56,5 thousand tons

Plot №	Well category	Stock	Number of tested wells	Part of wells tested, %
SC-3 bis⁺	Injection	14	12	85.7
	Production	20	5	25.0
	Control	5	0	0.0
	Total	39	17	43.6
[•] Inclinometers for wells		Production № - 9, 11, 12, 17, 18		Injection № - All except 1, 2

Table 1: Coverage of well tests using an inclinometer.

Figure 8: Comparison of the design and actual location of the trajectory of wells in plot SC-3 bis.

of oil was produced. Oil recovery in the developed areas has reached 38.0%, including 27.4% due to heat exposure. Accumulated steam-oil ratio was 2,02 t/t.

In Figure 11 contains a graph of oil production rate per unit area is shown. Figure 11 shows that a year after steam injection, the pace of oil withdrawal pace from 1 hectare is almost identical and averages of 350-400 tons/month.

In 2010, as part of a mini-project, technological parameters for development of experimental plots were first predicted by numerical simulation [2]. Afterwards, industrial material was accumulated during the operation of the experimental plots. It formed basis for adaptation of the experimental plots models [3], which made it possible to clarify forward-looking information presented in the mini-project. Figures 12 and 13 shows a comparison of the design (mini-project), in view of adaptation (model) and the actual oil recovery factor for the

Page 4 of 6

experimental plots. CMG software package was used for calculating the indicators (Figures 12-14).

From the results of adaption done, it should be noted that the historical production of liquid differs from the model. That is possible due to the inflow of additional water from nearby developed areas.

As seen from the above figures, the quality of forecasting technological parameters of development greatly depends on the quality of the initial information. It is quite difficult to obtain at the initial design stage, and can be subsequently obtained by analyzing

Figure 12: Three-dimensional geological filtration model of plot SC-3 bis.

Figure 16: Temperature distribution along the wellbore (September 2015).

field information using modern software applications which give more accurately predicted operational modes of the pilot sites [4,5].

In the fourth quarter of 2015, a study to determine collectability by injecting coolant into the reservoir was conducted on the pilot plot. Collectability at plot SC-3 bis which 18.69 t /(d•atm) was determined by the test results.

Also, temperature along the wellbore of control wells № 2K, 3K, 4K, 5K of plot SC–3 bis was measured in June and December of 2015 by the company «Argosy Analytics» LLC. The results of tests are shown in Figures 15 and 16, which shows that at the wellhead zone where production wells are cased to a depth of 50 m using heat-insulated columns, the formation temperature ranges from 35°C to 65°C (well № 2K-80°C) and 55°C on average. That is significantly lower than in the more remote areas at the top of the reservoir. The rest of the formation

Page 6 of 6

to the bottom of the well is uniformly warmed to a temperature of up to 80°C on average, with the temperature at the bottom of well N^0 2K up to 90°C to 100°C [6].

The tests made mapping of the thermal fields of plot SC-3 bis (Figures 17-19) possible for the first time. When creating the map, thermometric test results of surface wells N^0 2028-2033 drilled along the contour of the pilot plots were also used. Testing the wells likewise produced the following results. Average temperature in the formation interval: in well N^0 2030 - about 80°C, well N^0 2031 - about 100°C, well N^0 2033 - about 90°C.

Results

These data fully confirm test results obtained from underground

wells. The most and least heated areas can be seen on the maps shown in Figures 17-19 (June 2015) will continue to develop recommendations for a more rational distribution of vapor on the developed area of the site. The maps shown in Figures 17-19 (June 2015) can be seen the most and least warmed areas. That makes it possible for future development recommendations relating to a more rational distribution of vapor on the developed area of the site. Following the events carried out in September using well temperature measurement data, an updated map of the thermal field was being created (Figure 19). The figure shows that the implementation of measures for redistribution of steam into the reservoir, helped to reduce the temperature in the left side of the reservoir (from 100°C to 90°C) and slightly increased (align) it into the right side of the reservoir.

Conclusion

1. Application of a thermal mining method is a very effective technology for development of shallow heavy oil fields. Yaregskoye deposit is the first oil field, where steam assisted gravity drainage in mining form is used since 1968.

2. Currently, various mining systems are used for development of heavy oil fields. For example, one of the very effective systems is a single horizon system (analog SAGD). The efficiency of this system has been tested upon experimental grounds.

3. For prediction of technological parameters CMG software (Stars module) has been used.

4. Nowadays, specialists in mining oil fields utilize modern methods and equipment for control and monitoring of technological parameters and safety.

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