

Control of movement of heat front during oil reservoir with thermal treatment

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Relevance. For efficiency of oil field development, Enhanced Oil Recovery (EOR) methods are used. These methods can be classified into physical-chemical, thermal, microbiological, nuclear, etc. Among these treatments, the thermal method has a special place. It is related to the fact, that these methods are applied to the formations with scavenger (tight) oil, where ultimate oil recovery factor otherwise cannot exceed 0.2–0.3. Thermal methods are aimed to reduce the viscosity of the oil, thus increasing its mobility in the reservoir. The method is based on pumping the driving substance (steam or hot water) into the reservoir, and also on burning the oil in the reservoir (in-situ combustion).

Purposes and objectives of the study. The efficiency of the thermal treatment largely depends on geological and physical conditions of the oil reservoir – its depth, physical and chemical characteristics of the fluids, reservoir type, oil, gas and water saturation.

The substance to be heated in the reservoir is oil. However, part of thermal energy heats water and the rock as well. Therefore, it is very important to study the reservoir before the start of thermal treatment. Geologically heterogeneous layers especially require detailed study.

The thermal methods have been tested on the reservoirs, occurring at different depth. However, the efficiency of thermal treatment decreases with depth. The reason for that is the loss of the heat on its way in the borehole, from one hand, and higher temperature of the formation itself, on the other. That is why, the application of the thermal methods on the deeper horizons are limited.

Results and recommendation. Apparently, the successful application of thermal treatment of the reservoirs requires the systematic monitoring of the development process, which allows to correct the treatment process in a timely manner. Getting the information about formation current physical characteristics, making temperature measurements are challenging and expensive processes. The processing of the information also takes time. All of this can have negative effect on ultimate recovery factor. Usually, construction of isotherm maps is recommended for thermal treatment monitoring. However, these maps not always indicate the direction of the movement of the injected heat. Thus, the effective method of controlling and monitoring of the thermal treatment is very relevant task of the reservoir geology.

Keywords: reservoir, oil recovery, thermal treatment, temperature, exposure to steam, in-situ combustion, water mineralization.

Introduction

For efficiency of oil field development, Enhanced Oil Recovery (EOR) methods are used. These methods can be classified into physical-chemical, thermal, microbiological, nuclear, etc. [1–3].

Among these treatments, the thermal method has a special place. It is related to the fact, that these methods are applied to the formations with scavenger (tight) oil, where ultimate oil recovery factor otherwise cannot exceed 0.2–0.3 [4]. Thermal methods are aimed to reduce the viscosity of the oil, thus increasing its mobility in the reservoir. The method is based on pumping the driving substance (steam or hot water) into the reservoir, and also on burning the oil in the reservoir (in-situ combustion).

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Suggested method

The method is based on the fact, that injected heat transfer agent will increase the temperature and mobility of fluids, but will also change the ion and salt composition of the formation water. The heat transfer agent can be steam, hot water, as well as the products of combustion of oil in the reservoir [5–7]. One has to pay attention to the fact that the water flow in the reservoir is faster than the spreading of the heat in the rock matrix or in the saturated fluids. Therefore, the change in water chemistry is meaningful indicator, which allows finding areas and zones of the field affected by thermal treatment. The behavior of chemical components of the solution depends on the method of treatment. Injected steam will decrease the salinity, or mineralization, since injected substance is basically distilled water. In-situ combustion decreases the viscosity of oil, but also increases the temperature

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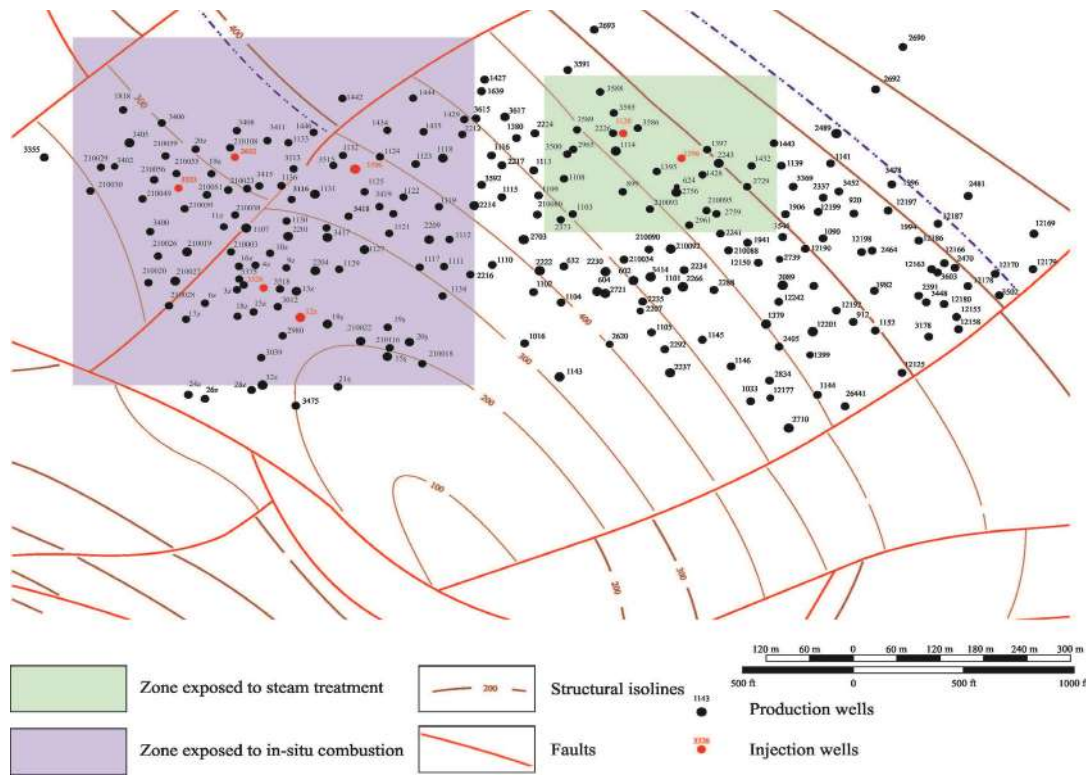


Figure 1. Thermal treatment zones in Balakhany-Sabunchi-Ramany field.
Рисунок 1. Зоны тепловой обработки пласта в месторождении Балаханы-Сабунчи-Раманы.

of formation water, which increases its reactivity and solubility of components of the rock matrix. Therefore, water produced with the oil will have higher mineralization and, as a rule, the content of Na + K and Cl ions will increase.

As for hot water injection (which has not been applied in the Azerbaijan oil fields), it is reasonable to suppose that the water chemistry will change according to the chemical composition of the dissolved salts in the injected water [8].

Case studies

Below are the specific examples of realization of the suggested method.

Exposure to steam. This method was successfully used in the oil reservoir horizons II KS₁₁ of Balakhani-Sabunchi-Ramany field (Khorasan Zone). The target is represented by frequent and uniform alternation of thin (35–45 m thick) interbeds of argillaceous and sandy rocks. Average porosity is 25% and average permeability is 0.215 mkm² (215 mDa). The area covered by thermal treatment is not complicated by faults and has 18–25° dip angles.

In place conditions the density of oil is 0.920–0.935 gcc (19.8–22.3 API), while the viscosity is 75–110 mPa × s. Although the horizon has been developed since 1924, at the beginning of treatment the current oil recovery coefficient was only 0.19. Average daily well rate were between 0.6–3.2 t (4–22 bbl) oil and 0.1–8.0 m³ water. WCO was 55–65%, while formation pressure of the site fluctuated from 0.07 to 1.25 MPa. To enhance filtration properties of oil in porous environment of the studied zone steam injection was first implemented in well No. 1396 (1969), and then in well No. 1128 (1970). The temperature of working agent (steam) at the wellhead was 200-220 °C at 3.0 MPa injection pressure (Fig. 1).

It must be noted that the steam injection operations create three specific phase zones – steam drive zone, hot condensate zone and unswept zone [9]. Each of indicated zones affects each other. By compensating each other these zones indicate the nature and direction of heat front.

The work describes the study results of impact of temperature on physical and chemical features of the oil and reservoir water in test wells (No. 2220, 2281, 2547, 2238, 2227). It was established that the test wells exhibit regular decrease in viscosity and density of produced oil with rising temperature. However, the wells where no changes in the temperature of formation were observed (2236), there was some improvement in oil mobility. This suggested that the thermal flow affected wider area. At that, the studies indicated the considerable changes in reservoir water even in the wells where formation temperature did not change. The salinity of this water reduced from 2.5–3.1 to 0.5–2.8 °Be as a result of mixture with steam condensate (Table 1).

Comparison of physical-chemical characteristics of formation water has shown that its properties change as a result of advanced penetration of steam condensate (which is actually distilled water) via more permeable sub-layers. Such situation was observed even in wells (No. 1397, 1934), where other geological-engineering characteristics remained stable (Fig. 2).

In the course of controlled steam treatment, it was found that monitoring of hydrochemical conditions within formations in dynamics allows identifying directions of the heat flow in formations, and this can be used for control of used treatment method [4, 10].

In-situ combustion. This method is based on the capability of hydrocarbons to release heat as a result of oxidizing reactions. Heat generation directly within formation is main advantage and characteristic feature of this method. In-situ combustion works efficiently in clastic reservoirs. Disadvantage of this method is that more than 25% of oil in the reservoir is burned as a fuel, whilst final oil recovery can be increased to 20% when using this method [8, 11–15].

Table 1. Physical-chemical characteristics of formation water of horizon II K_S, Balakhany-Sabunchi-Ramany field.

Таблица 1. Таблица 1. Физико-химические показатели пластовой воды на залежах горизонта II КС в месторождении Балаханы-Сабунчи-Раманы.

| Well | Before the treatment | | | | | | After the treatment | | | | | |
|------|----------------------|---------------------------|------------------|---------|--------|------------------|---------------------|---------------------------|------------------|---------|--------|------------------|
| | °Be | Equivalent values, equiv. | | | | | °Be | Equivalent values, equiv. | | | | |
| | | Cl | HCO ₃ | Ca + Mg | Na + K | Σ _{a+k} | | Cl | HCO ₃ | Ca + Mg | Na + K | Σ _{a+k} |
| 2220 | 2.9 | 0.0311 | 0.0085 | 0.0014 | 0.0802 | 0.1212 | 0.5 | 0.019 | 0.0021 | 0.0013 | 0.0032 | 0.0261 |
| 2281 | 2.9 | 0.0324 | 0.009 | 0.0017 | 0.0838 | 0.1269 | 2.8 | 0.0313 | 0.0091 | 0.002 | 0.0389 | 0.0818 |
| 1431 | 3.1 | 0.0335 | 0.009 | 0.0015 | 0.0862 | 0.1302 | 0.7 | 0.021 | 0.0034 | 0.0009 | 0.0057 | 0.0315 |
| 1397 | 3.0 | 0.0322 | 0.0093 | 0.0016 | 0.084 | 0.1271 | 2.6 | 0.0283 | 0.0091 | 0.0013 | 0.0156 | 0.0758 |
| 1432 | 2.8 | 0.025 | 0.0112 | 0.0012 | 0.0733 | 0.1107 | 2.7 | 0.0256 | 0.0109 | 0.0014 | 0.0356 | 0.054 |
| 2547 | 2.5 | 0.0239 | 0.0081 | 0.0019 | 0.065 | 0.0989 | 1.7 | 0.0156 | 0.0077 | 0.0011 | 0.0229 | 0.0478 |
| 2238 | 2.7 | 0.0256 | 0.0104 | 0.001 | 0.073 | 0.11 | 2.5 | 0.0244 | 0.0101 | 0.001 | 0.0339 | 0.0699 |
| 1934 | 3.1 | 0.0341 | 0.009 | 0.0015 | 0.0873 | 0.1319 | 2.8 | 0.0291 | 0.0098 | 0.0014 | 0.0383 | 0.0791 |
| 2729 | 2.7 | 0.0246 | 0.0108 | 0.0011 | 0.0718 | 0.1083 | 2.7 | 0.0261 | 0.01 | 0.0014 | 0.0153 | 0.0533 |
| 2248 | 2.9 | 0.0282 | 0.01 | 0.0013 | 0.0776 | 0.1171 | 2.8 | 0.0277 | 0.0106 | 0.0013 | 0.0175 | 0.0576 |
| 2236 | 2.5 | 0.0232 | 0.009 | 0.0015 | 0.0655 | 0.0992 | 1.7 | 0.0124 | 0.0069 | 0.0011 | 0.0188 | 0.0397 |

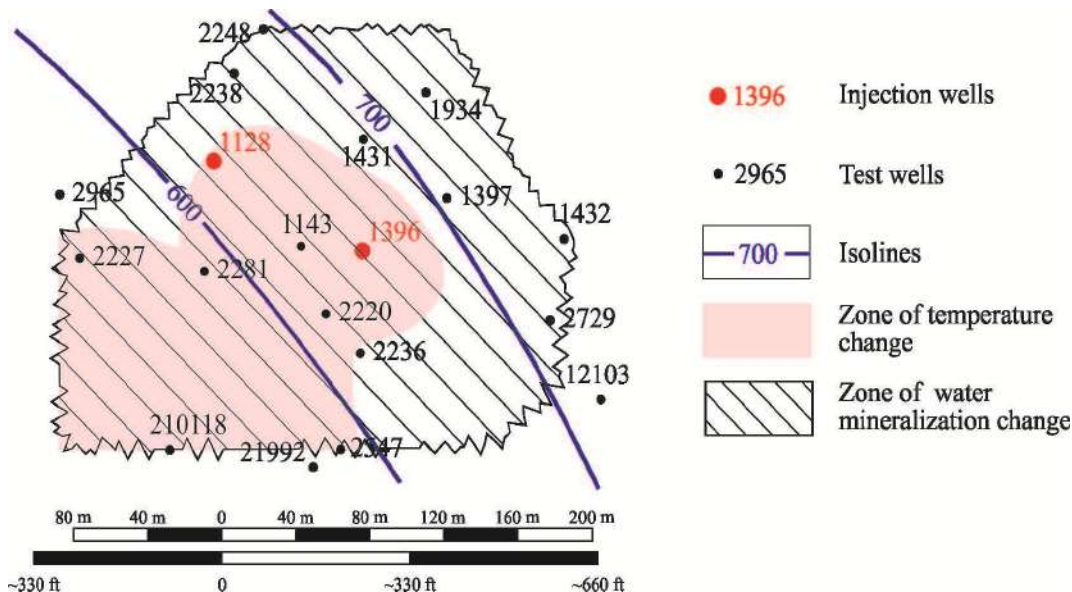


Figure 2. Map of heat distribution as a result of steam treatment in Khorasany area of Balakhany-Sabunchi-Ramany field.

Рисунок 2. Карта распределения тепла в результате паровоздействия в месторождении Балаханы-Сабунчи-Раманы (площадь Хорасаны).

Let us note that as a result of process of combustion in the reservoir, ion-salt composition of formation water from the treated wells has changed. We registered this effect in wells of the Balakhany-Sabunchi-Ramany and Pirallakhi fields.

1. *Horizon PKu of the Balakhany-Sabunchi-Ramany field (Khorasany area).* Here PK suite, unlike other areas of the field is characterized by low oil recovery factors (< 0.30), which is mainly related to high viscosity of oil (> 50 mPa · s). Accordingly, in 1973, people began to apply thermal treatment methods, in-situ combustion, in particular.

Summary of geological-engineering characteristics of target is the following.

Development of PKu began in 1919. Numerous wells have been drilled during the whole period of development, however, most wells were soon returned to the overlying formations due to low rates. The process of in-situ combustion was applied in wells No. 3326, 3323, 12z, 3396, 2632. More than 40 producers undergone treatment (Fig. 3).

Treatment continued up to 1995; during the whole period more than 600 thousand m³ of water and over 200 million m³ of compressed air have been injected into reservoir. As a result, about 230 thousand tons (1.5 mm bbl) of incremental oil was produced owing to its improved mobility at the expense of reduction of viscosity. Treatment was carried out under systematic monitoring and control. It should be noted that while temperature changes in the wells happened in different level, in most of them (particularly in wells 3375, 3z and 3518), physical-chemical characteristics of formation water changed significantly (Table 2, Fig. 4).

Period of thermal stimulation is shown in grey color.

It can be seen from the presented data that in the process of in-situ combustion in horizon PK_u at the Khorasany area, hydro-chemical parameters of formation experience various changes. In all cases increase of values of Na + K и Cl ions is clearly seen, which allowed identifying zones of heat flow effect across the area.

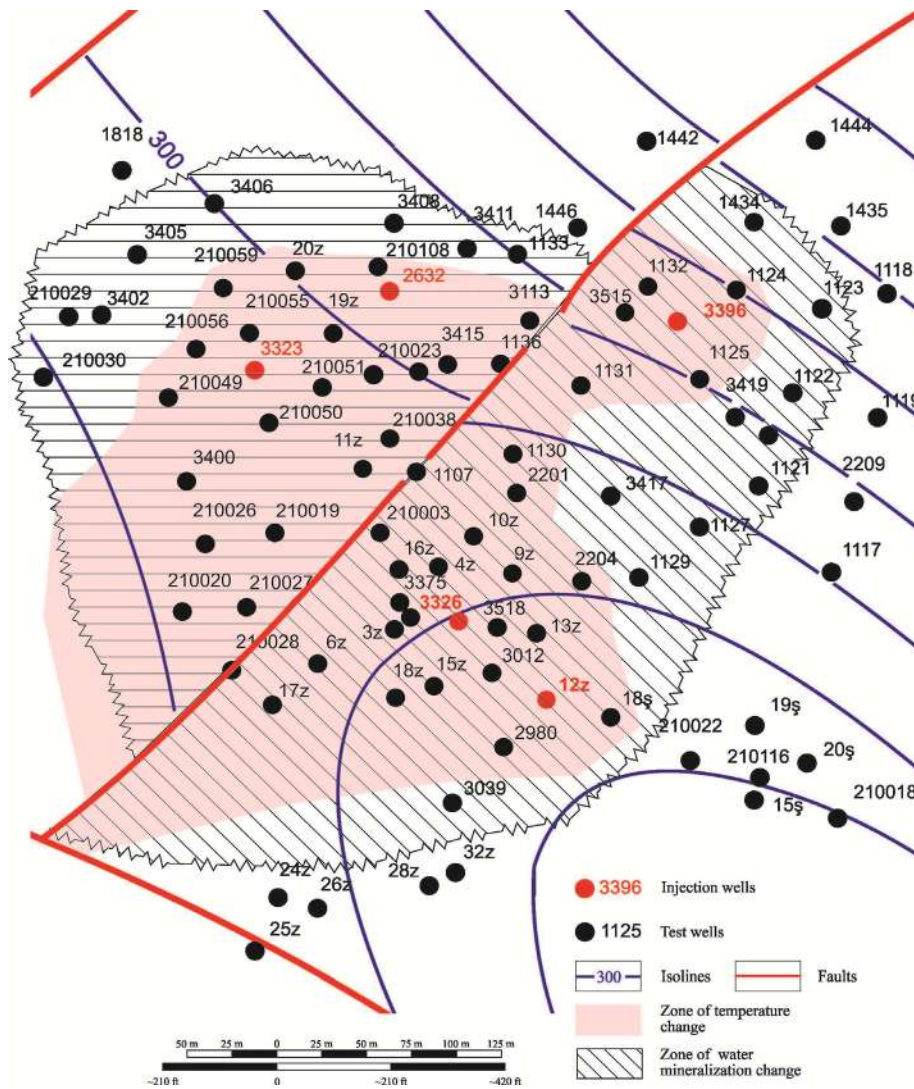


Figure 3. Map of heat distribution as a result of in-situ combustion in Khorasany area of Balakhany-Sabunchi-Ramany field.
 Рисунок 3. Карта распределения тепла в результате внутрипластового горения в месторождении Балаханы-Сабунчи-Раманы (площадь Хорасаны).

Table 2. Physical-chemical characteristics of formation water of horizon PK_u at Balakhany-Sabunchi-Ramany field.
 Таблица 2. Физико-химические показатели пластовой воды на залежах горизонта PK_u в месторождении Балаханы-Сабунчи-Раманы.

| Well No. 3375 | Equivalent values | | | | | | |
|-----------------------------|-------------------|-----------------|------------------|--------|--------|--------|------------------|
| | Cl | SO ₄ | HCO ₃ | Ca | Mg | Na + K | Σ _{a+k} |
| <i>Before the treatment</i> | | | | | | | |
| 24.06.1971 | 0.0252 | 0.0001 | 0.0074 | 0.0002 | 0.0017 | 0.0305 | 0.0651 |
| 28.07.1971 | 0.0235 | 0.0002 | 0.0067 | 0.0006 | 0.0012 | 0.0284 | 0.0606 |
| 22.12.1971 | 0.0235 | 0.0001 | 0.0066 | 0.0005 | 0.0016 | 0.0281 | 0.0604 |
| 19.03.1972 | 0.0275 | 0.0001 | 0.0072 | 0.0006 | 0.0013 | 0.0328 | 0.0695 |
| 17.06.1972 | 0.032 | 0.0003 | 0.0054 | 0.0006 | 0.0017 | 0.0354 | 0.0754 |
| 03.09.1972 | 0.028 | 0.0002 | 0.0068 | 0.0001 | 0.0022 | 0.0327 | 0.07 |
| 18.01.1973 | 0.0255 | 0.0004 | 0.0069 | 0.0006 | 0.0016 | 0.0306 | 0.0656 |
| <i>After the treatment</i> | | | | | | | |
| 09.04.1973 | 0.1004 | 0.0086 | 0.0059 | 0.0154 | – | 0.0995 | 0.2298 |
| 26.06.1973 | 0.087 | – | 0.0062 | 0.0012 | 0.0039 | 0.0881 | 0.1864 |
| 07.09.1973 | 0.029 | – | 0.0069 | 0.0002 | 0.0019 | 0.0338 | 0.0718 |
| 09.02.1974 | 0.0265 | 0.0001 | 0.0019 | 0.0004 | 0.0014 | 0.0314 | 0.0617 |
| 19.05.1974 | 0.0245 | – | 0.0068 | 0.0004 | 0.0017 | 0.0292 | 0.0626 |
| 09.08.1974 | 0.026 | 0.0006 | 0.0063 | 0.0001 | 0.0023 | 0.0315 | 0.0668 |
| 14.12.1974 | 0.0275 | 0.0001 | 0.0075 | 0.0002 | 0.0021 | 0.0327 | 0.0701 |

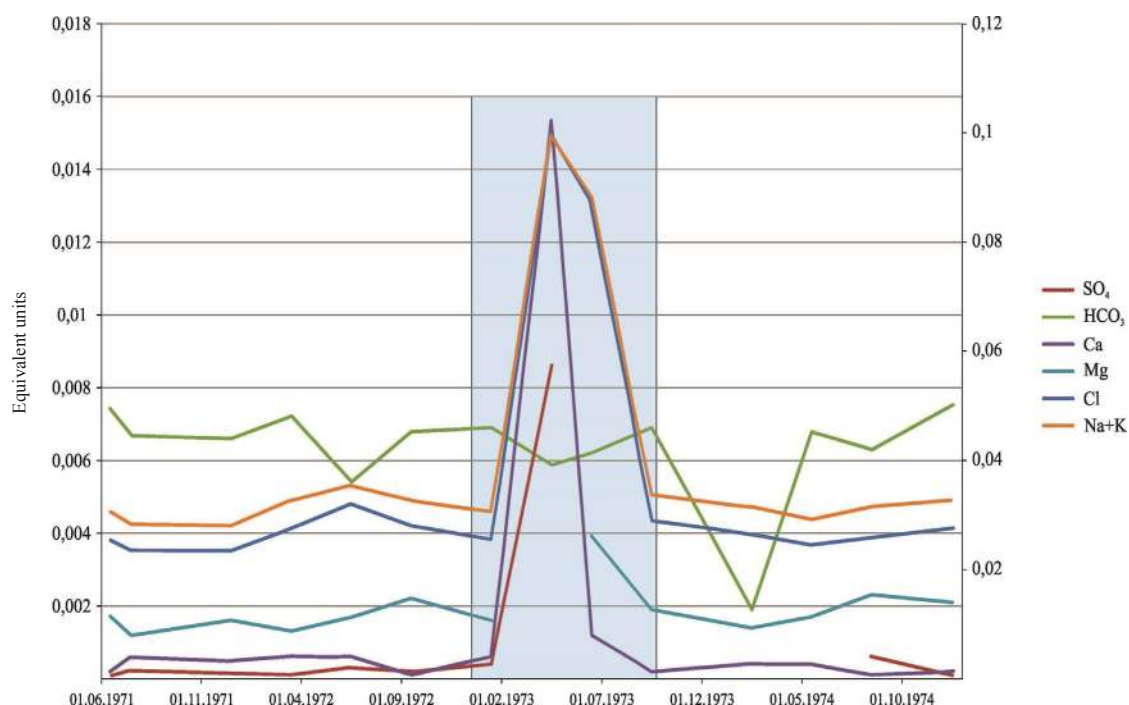


Figure 4. Change of physical-chemical characteristics of formation water in time (well No. 3375).
 Рисунок 4. Изменение физико-химических показателей пластовой воды с течением времени (скважина 3375).

Table 3. Physical-chemical characteristics of formation water of horizon KCu at Pirallakhi field.

Таблица 3. Физико-химические показатели пластовой воды горизонта KCu в месторождении Пираллахи.

| Well No. 633 | Equivalent values | | | | | |
|-----------------------------|-------------------|-----------------|------------------|--------|--------|--------|
| Measurement date | Cl | SO ₄ | HCO ₃ | Ca | Mg | Na + K |
| <i>Before the treatment</i> | | | | | | |
| 24.01.1978 | 0.1550 | – | 0.0017 | 0.0071 | 0.0050 | 0.1446 |
| 21.02.1979 | 0.1430 | 0.0009 | 0.0012 | 0.0107 | 0.0076 | 0.1268 |
| 30.10.1979 | 0.1100 | 0.0013 | 0.0019 | 0.0067 | 0.0063 | 0.1002 |
| 11.01.1980 | 0.1515 | 0.0007 | 0.0010 | 0.0108 | 0.0066 | 0.1358 |
| 20.03.1980 | 0.1725 | 0.0009 | 0.0008 | 0.0132 | 0.0071 | 0.1539 |
| 23.10.1980 | 0.1290 | 0.0023 | 0.0008 | 0.0094 | 0.0073 | 0.1154 |
| <i>After the treatment</i> | | | | | | |
| 17.02.1981 | 0.2000 | 0.0001 | 0.0007 | 0.0112 | 0.0020 | 0.1876 |
| 25.02.1981 | 0.2120 | 0.0001 | 0.0004 | 0.0150 | 0.0077 | 0.1898 |
| 27.03.1981 | 0.2085 | 0.0001 | 0.0004 | 0.0139 | 0.0104 | 0.1847 |
| 11.05.1981 | 0.1360 | 0.0004 | 0.0017 | 0.0084 | 0.0061 | 0.1236 |
| 20.05.1981 | 0.1610 | 0.0014 | 0.0012 | 0.0162 | 0.0046 | 0.1428 |
| 07.08.1981 | 0.1405 | 0.0015 | 0.0012 | 0.0134 | 0.0028 | 0.1270 |
| 18.12.1981 | 0.0165 | 0.0053 | 0.0004 | 0.0016 | 0.0052 | 0.0154 |
| 26.01.1982 | 0.0720 | 0.0012 | 0.0032 | 0.0010 | 0.0053 | 0.0664 |
| 15.03.1983 | 0.0745 | 0.0010 | 0.0038 | 0.0032 | 0.0046 | 0.0745 |
| 31.05.1983 | 0.1025 | – | 0.0042 | 0.0032 | 0.0036 | 0.0999 |
| 26.03.1984 | 0.0965 | – | 0.0039 | 0.0014 | 0.0029 | 0.0921 |
| 19.06.1984 | 0.0800 | – | 0.0041 | 0.0018 | 0.0052 | 0.0771 |
| 08.07.1984 | 0.0845 | 0.0004 | 0.0029 | 0.0052 | 0.003 | 0.0796 |
| 23.10.1984 | 0.0865 | – | 0.0036 | 0.0031 | 0.0039 | 0.0831 |
| 15.11.1984 | 0.0870 | – | 0.0043 | 0.0037 | 0.0048 | 0.0828 |
| 12.12.1984 | 0.0610 | 0.0010 | 0.0039 | 0.0034 | 0.0035 | 0.0590 |

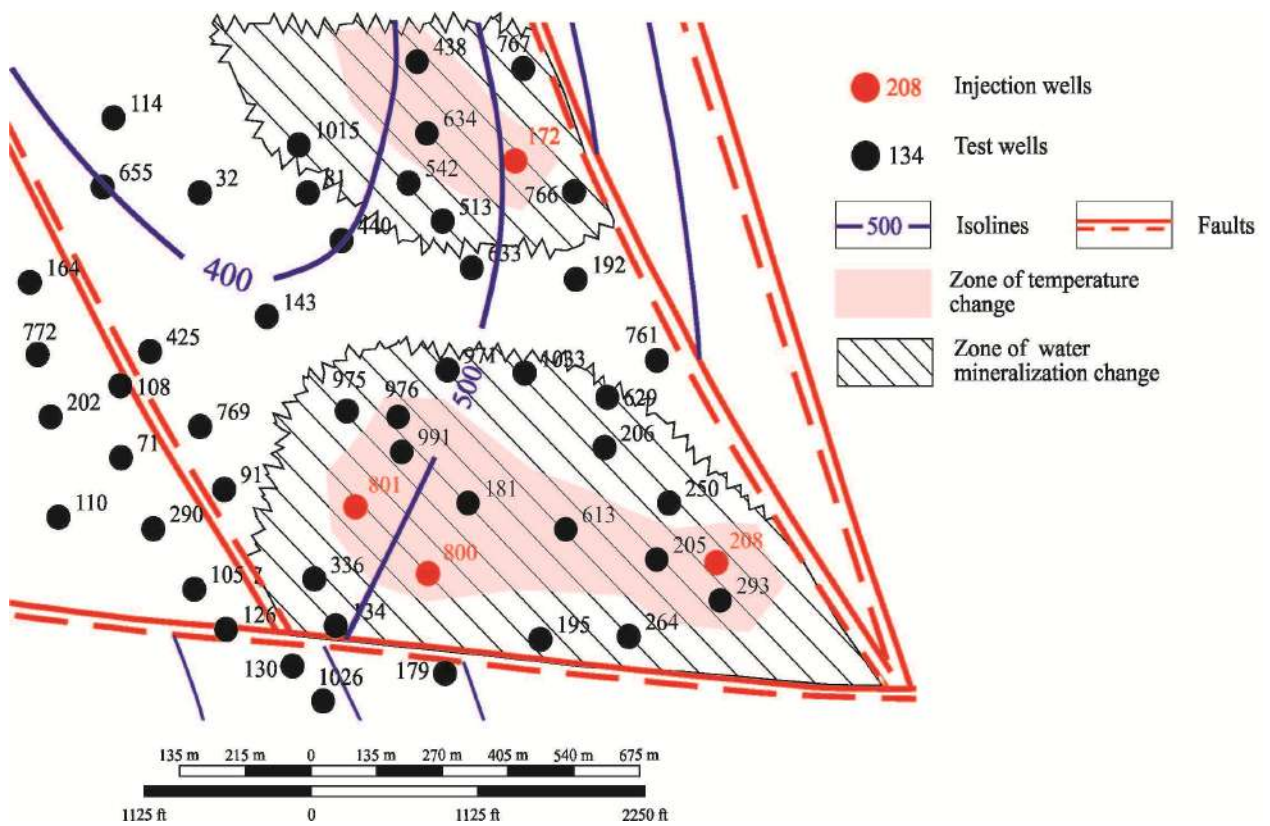


Figure 5. Map of heat distribution as a result of in-situ combustion in horizon KS_u of Pirallakhi field.
 Рисунок 5. Карта распределения тепла в результате внутрипластового горения в залежах горизонта KS_u месторождения Пираллахи.

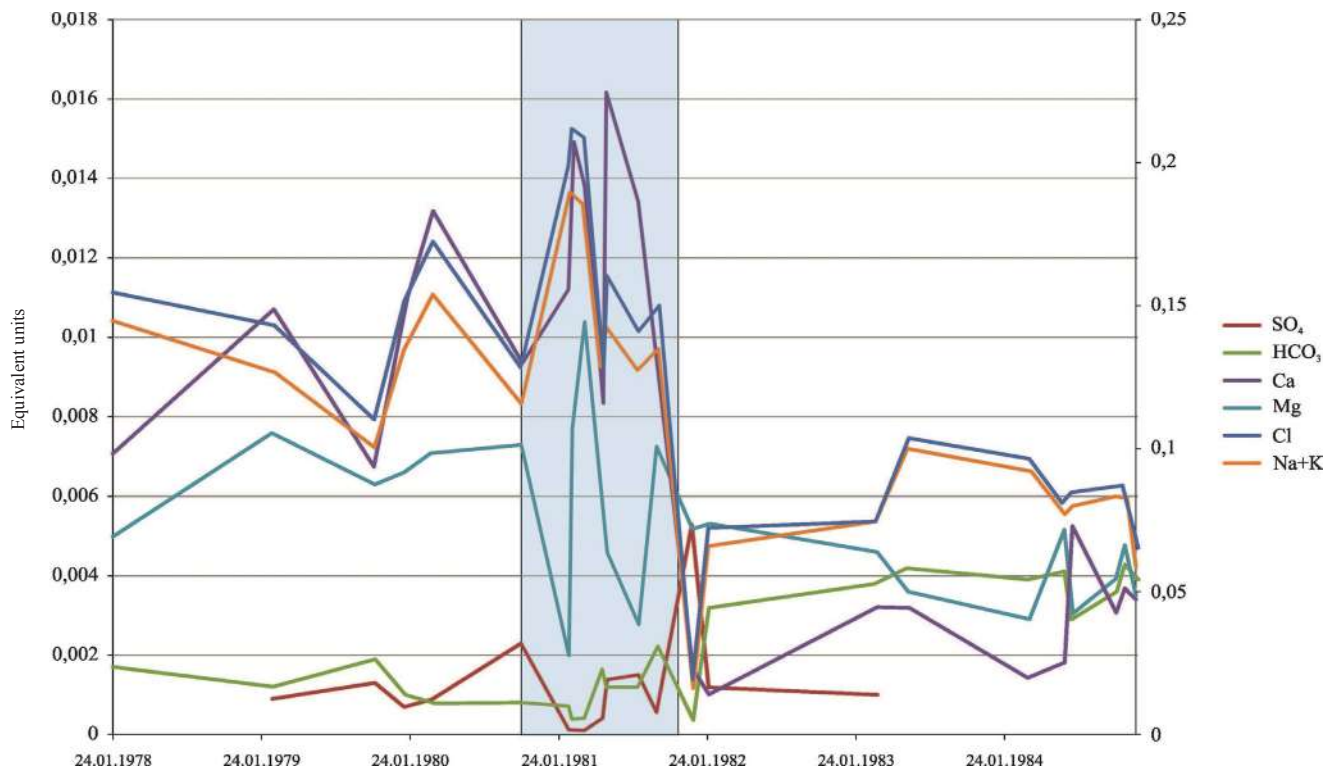


Figure 6. Change of physical-chemical characteristics of formation water in time (well No. 633).
 Рисунок 6. Изменение физико-химических показателей пластовой воды с течением времени (скважина 633).

2. *Horizon II K_u of the Pirallakhi field.* Horizon K_u of the Pirallakhi field is in development over 70 years. This horizon is quite heterogeneous and compartmentalized, which lead to different level of recovery in different blocks. Accumulation of significant remaining recoverable reserves of highly viscous oil in come blocks required design and application of in-situ combustion method. This method was applied in a number of wells: well 208 – 1974; wells 800 and 801 – 1976; well 172 – 1981; well 843 – 1982 (Fig. 5).

During the period of formation treatment, alongside with other geological-engineering measures hydrochemical studies were carried out. It should be noted that vast volume of data had been accumulated for this target, and increased content of Na + K and Cl ions in formation water was registered. Results of analyses for a number of wells are presented in Table 3, Fig. 6.

Period of thermal stimulation is shown in grey color.

As follows from Fig. 3, 4, 6, affected zones established just by data of thermal studies cover only part of areas, which is related to natural physical tendency of heat to move to elevated parts of the structure. Chemical-structural changes in mineralization of water encompass much greater area, giving better indication of coverage with thermal treatment.

Thermal treatment in a form of hot water injection was not used in the Azerbaijan fields. Nevertheless, one can assume that on injection of hot water mineralization of formation water will change depending on the ion-salt composition of injected water.

Conclusions

1. For the improvement of mobility of highly-viscous oils in reservoirs temperature within the development targets has to be increased.

2. In the process of thermal treatment, in any modification, specific variations in chemical composition of formation water are observed.

3. This effect is in favor of inclusion of water sampling and hydrochemical analysis data into monitoring process of formations thermal treatment.

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Контроль за продвижением теплового потока в процессе разработки нефтяных месторождений с применением термической обработки

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Актуальность. Для увеличения нефтеотдачи пластов в процессе разработки залежей применяются тепловые методы (закачка в пласт пара и горячей воды, внутрискважинное горение). Эффективное применение этих методов требует надежного контроля проводимых процессов. С этой целью обычно проводятся соответствующие замеры в скважинах, результаты которых отражаются на картах изотерм. Сопоставление таких карт, составленных для различных периодов разработки залежей, позволяет получать информацию о направлении и скорости продвижения теплоносителя по пласту. В итоге выдвигается концепция о регулировании (если это необходимо) проводимых процессов.

Цель и задачи исследования. Проводимые нами геолого-промысловые исследования по месторождениям Азербайджана показывают, что для более надежного контроля за тепловоздействием целесообразно использовать данные о гидрохимии пласта. Так, при внедрении теплоносителя не только повышается температура пласта и тем самым снижается вязкость и плотность пластовых нефтей, но и изменяются физико-химические характеристики пластовых вод. Следует отметить и то, что в процессе термовоздействия наряду с пластовыми флюидами подвергается изменениям и порода этого пласта. В итоге тепло, продвигающееся от возбуждающей скважины к скважинам реагирующим, представляет собой весьма сложную термодинамическую систему. К тому же процесс изменения гидрохимии пласта всегда опережает подобные процессы в нефтях и породах залежи. Именно этим обстоятельством обосновывается необходимость включения в комплекс исследований по контролю за тепловоздействием информации о гидрохимии пласта.

Вывод. Опираясь на материалы разработки ряда месторождений Азербайджана, авторы выявили механизм изменчивости теплового режима залежей. В частности, было установлено, что при закачке в пласт пара, представляющего собой, по существу, дистиллированную воду, соленость вод залежей уменьшается; при внутрискважинном горении за счет резкого повышения температуры пласта повышается и химическая активность вод. Это, как правило, приводит к изменению химизма вод (содержание Na + K и Cl повышается). Концепция, выдвинутая в данной статье, подтверждается геолого-промысловыми данными и иллюстрируется соответствующими картами и таблицами.

Ключевые слова: резервуар, нефтеотдача, термическое воздействие, температура, паровоздействие, внутрискважинное горение, минерализация воды.

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