Effect of freshwater injection on Jurassic well injectivity

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Abstract. The paper deals with the research of mineralogical composition of clay fraction of rock samples, injection of different water in the fields of Western Siberia, analyzed well performance. It was found that the final oil recovery of reservoirs at reservoir pressure maintenance by water injection is significantly affected by the swelling of clay minerals.

1 Introduction

Water injection into the reservoir is one of the main ways to maintain reservoir pressure in a fallow to preserve reservoir energy and maximize oil recovery. Various water is used as working agents - formation water, water extracted from aquifers, produced water and water from open sources (fresh water). To date, the effectiveness of fresh water injection remains an open question.

Since 1990, research activities on the method of water flooding with low-salinity water have sharply increased abroad, which is reflected in the number of publications on this topic [1]. This type of waterflooding can be considered as an improved version of simple waterflooding, since it is based solely on adjusting the salinity and ionic composition of injected water. There are suggestions that this technology is very cost competitive as it utilizes existing water injection as well as production facilities with minimal additional investment.

Producing oil using advanced waterflooding processes by adjusting the salinity and ionic composition of injected water is not a simple process. It involves complex and competing mechanisms relating to both fluid-fluid and fluid-rock interactions. The primary mechanisms and conditions required for enhanced oil recovery in both sandstones and carbonates are still far from being fully understood.

The widely publicized results of several macroscopic laboratory research studies have certainly indicated the importance of wettability changes in the observed additional oil recovery. However, the change in wettability represents only a general indication of the various interactions between atoms and molecules occurring at the microscopic scale of pores. In addition, water ions are very small in size within a few angstroms, which adds another layer of complexity. As a result, classical macroscopic laboratory methods will not be able to answer the key question: what actually happened at the very fine atomic and

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molecular levels in these advanced waterflood processes and what caused the so-called wettability change.

This deeper understanding of the interactions of different water ions at the atomic to molecular level at liquid-liquid and rock-liquid interfaces is necessary to fully understand the physics. Atomic to molecular scale data obtained from basic research need to be integrated with conventional macroscopic/core scale experimental data such as boundary angles, interfacial tension, zeta potentials, spontaneous absorption and core flooding [2].

Core flooding data reported in the literature show an additional increase in oil recovery from 4 to 19% due to the injection of dilute brine solutions [3-5]. The assumption is that injection of water with low salinity, changes reservoir wettability from mixed to more hydrophilic, improving microscopic displacement and reducing residual oil saturation [6].

Enhanced oil recovery by injection of low salinity water was the subject of laboratory work by the authors [6]. Based on the assumption that initial wettability was affected by the salinity contrast between the injected water and the accompanying brine, they conducted a series of core flooding experiments to study the release and movement of mixed wet fines and clay particles. During water injection, changes in wettability are usually detected by indirect changes in relative permeability and capillary pressure curves. The decrease in permeability and the increase in pressure drop indicate that the released particles improve microscopic displacement by blocking pore channels and directing flow to un-wetted areas. However, it has been argued that the mechanisms described are a consequence rather than a cause of the observed low salinity effect.

Thus, a significant number of publications contain data on the success of low-salinity water injection, but the effectiveness of this process is based on laboratory core research and modeling data.

2 Materials and methods

According to the author [7] fresh water injection for use in the system of reservoir pressure maintenance in terrigenous reservoirs of oil fields can lead to the following negative consequences [8-10]: - deterioration of natural rock permeability due to clay swelling processes; - change of wettability and decrease of relative rock permeability for oil; - emulsion-water blocking of pores and filtration channels; - deterioration of natural rock permeability due to salt deposition processes.

Let us dwell on estimation and determination of some technological indicators of development at injection of different water in the fields of Western Siberia. Let us consider the fields, the main object of development of which are formations of Jurassic sediments. The fields are featured by different reserve depletion with practically the same development period (Table 1). Of the 9 fields under consideration, fresh (river and produced) water was injected into 3 fields from the beginning of development with subsequent change to produced water, produced water by-product water or mixed water.

Table 1. Types of injected water by fields.

no.	Field	Entry into development	Selection from NCD	Water pumping			
				Fresh	Formation (Cenomanian)	By-products	Mixed
1	Severo-Khokhryakovskoe	1988	14.5	FR	FC	MX	FC+MX
2	Bakhilovskoye	1987	20.1	FR		MX	
3	Verkhnekolik-Yeganskoye	1990	73.7	FR		MX	
4	Suslikovskoye	1996	83.2		FC		
5	Permyakovskoye	1985	68.6		FC		FC+MX
6	Khokhryakovskoye	1985	62.2		FC		FC+MX
7	Koshilskoe	1992	35		FC	MX	FC+MX
8	Kolik-Yeganskoye	1997	51.4		FC		
9	Okunevskoye	2013	14.5		FC		

Analyzing the data on well injectivity and compensation of fluid withdrawals (Table 2) it can be noted that at Verkhnekolik-Yeganskoye field at fresh water injection the average injectivity is higher than at the fields where formation (Cenomanian) water was injected.

Table 2. Dynamics of injection well operation.

Field	year of commissioning	first year		after 5 years of operation		after 10 years of operation		in the history of development	
		average intake m^3/day	comp. current, %	average intake, m^3/day	comp. current, %	average intake, m^3/day	comp. current, %	average intake, m^3/day	comp. total, %
Severo-Khokhryakovskoe	1991	451	129	126	174	116	242	117	84
Bakhilovskoye	1988	204	36	169	115	149	279	127	119
Verkhnekolik-Yeganskoye	1992	621	47	353	118	379	115	269	96
Permyakovskoye	1986	274	44	182	205	245	191	187	105
Khokhryakovskoye	1987	440	122	293	133	192	127	186	108
Koshilskoe	1993	163	13	149	135	143	103	121	99
Kolik-Yeganskoye	2000	172	71	165	75	180	115	137	93

An objective explanation for this can be found by superimposing reservoir permeability data on this analysis (Figure 1).

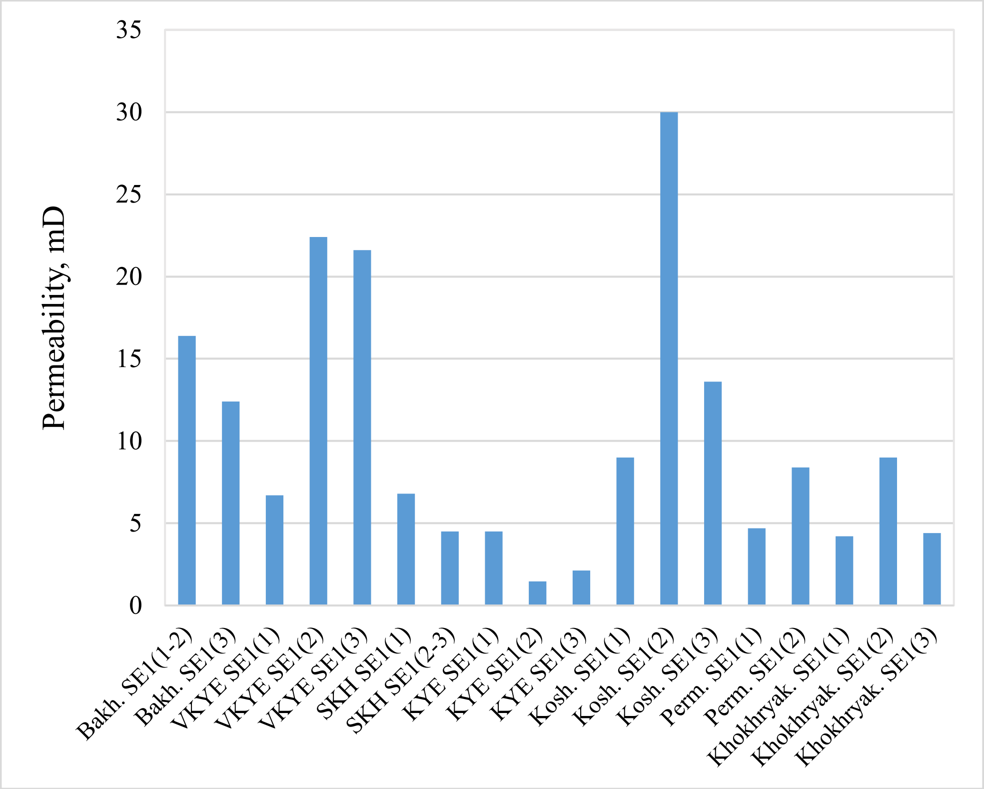

Fig. 1. Permeability of SW_1 formations of the considered fields.

Figure 2 shows the displacement coefficient for the considered formations. It should be noted that the displacement coefficient was obtained based on data obtained from own core research for all fields and it is slightly higher in the formations of the Severo-Khokhryakovskoye, Bakhilovskoye and Verkhnekolik-Yeganskoye fields.

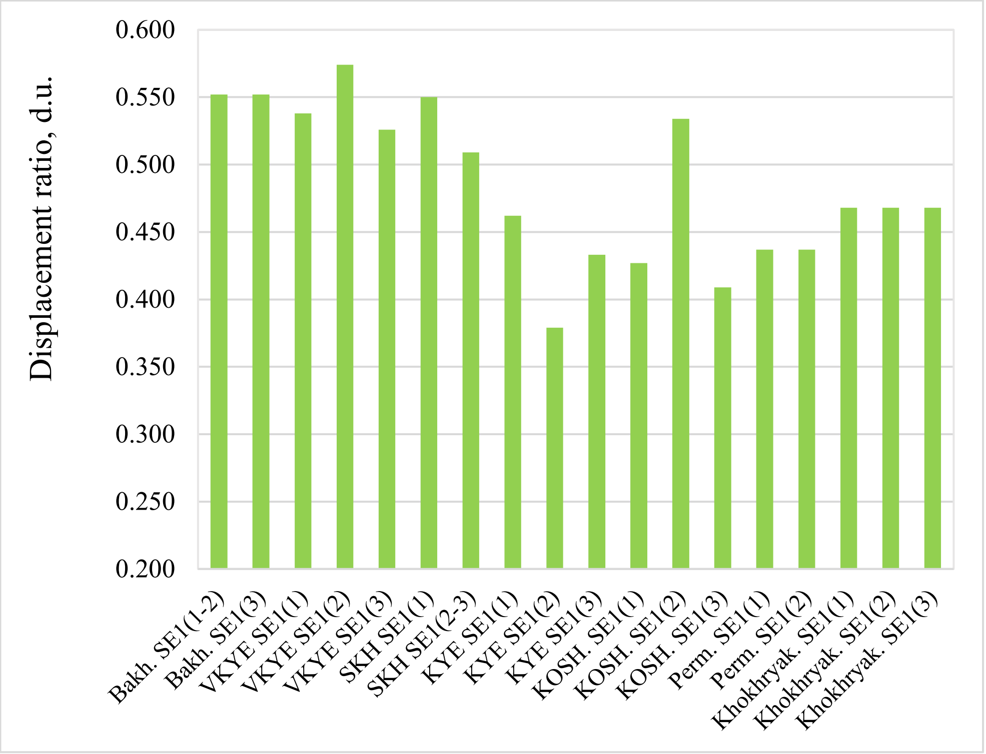

Fig. 2. Displacement coefficient of SW_1 formations of the considered fields.

But it is necessary to try to understand why in Bakhilovskoye and Severo-Khokhryakovskoye fields, despite the better reservoir properties compared to other fields, the withdrawal from the initial recoverable reserves is lower with practically the same development systems.

In our opinion, special attention should be paid to studying the mineralogical composition of the clay fraction of rock samples. According to the results analysis of studying the mineral composition by X-ray crystallography (XRC), there are clays of different mineralogical composition, attributed to kaolinite, chlorite, mica-bearing particles, etc. (Table 3). Each clay mineral, has different swelling and solubility coefficients, can differently affect the oil displacement capacity during fresh water filtration.

Table 3. Content of clay minerals in the formation SE_1 of the considered fields.

Field	Number of wells	Number of tests	Formation	Clay mineral content % (average value)					Swelling, %
				K	CH	HM	HM MS	M	
Severo-Khokhryakovskoe	13	145	SE1	70	12	14	6	0	2.56
Bakhilovskoye	19	265	SE1	65	16	13	5	0	1.98
Verkhnekolik-Yeganskoye	9	93	SE1	64	16	14	5	0	1.32
Koshilskoe	16	299	SE1	57	21	19	3	0	1.54
Khokhryakovskoye	8	115	SE1	64	18	14	3	1	1.50
Permyakovskoye	4	54	SE1	58	19	19	4	0	1.44
Kolik-Yeganskoye	5	51	SE1	66	12	16	6	0	1.91

Symbols: K - kaolinite, CH - chlorite, HM - hydromica, HMMS - mixed-layer formations of hydromica-montmorillonite series, M - montmorillonite.

The coverage of research of core samples from the SE_1 formation in these fields is quite good. A total of 1022 rock samples from 74 wells were studied. Kaolinite is the predominant clay mineral in the SW1 formation with an average of 58 to 70 %. Swellability varies from 1.32 to 2.56 %, the highest swellability index is in the Severo-Khokhryakovskoye field (Figure 3).

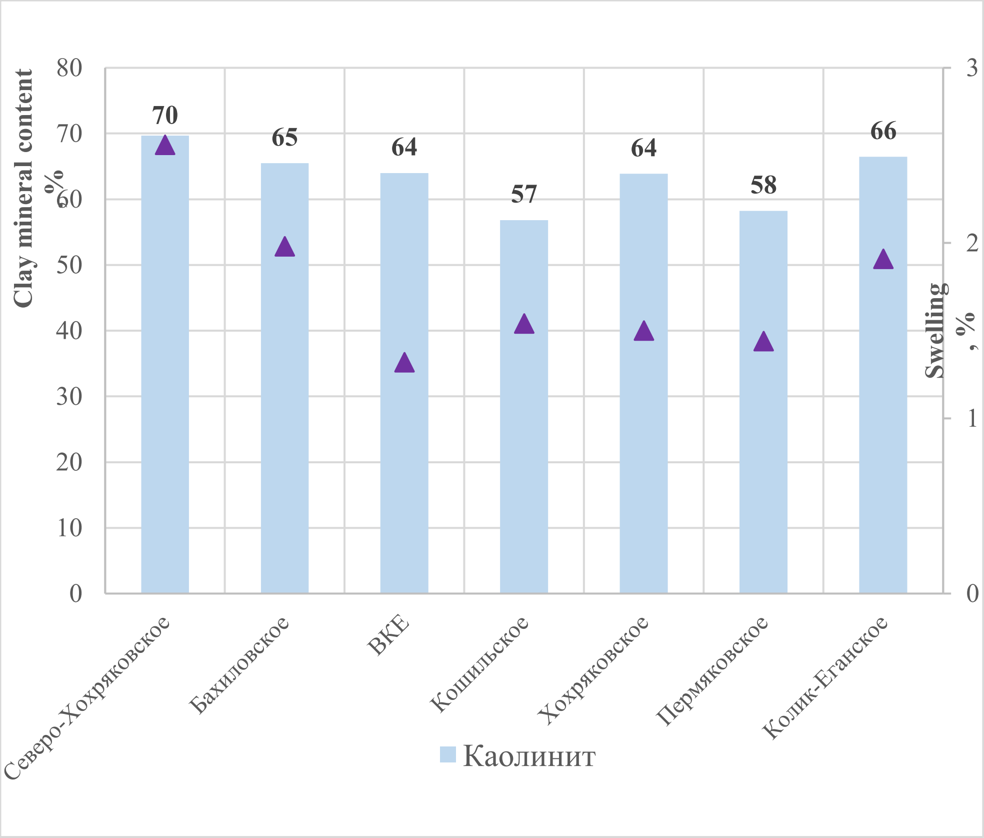

Fig. 3. Distribution of clay mineral content and swellability of the SW_1 formation by fields.

3 Results

Returning to the data in Table 2, it can be noted that the Severo-Khokhryakovskoye field has the lowest compensation for the entire history of development, as well as this field is featured by the lowest average injectivity of wells and withdrawal from NCD (14.5%). Also, during detailed analysis of the injection wells of the field it was found out that out of 28 wells, which operated for the first 10 years after the launch of the fresh water injection system, 12 wells were shut down due to a decrease in injectivity (according to the monthly operational reports of the wells). Figures 4-6 show examples of injection well performance dynamics.

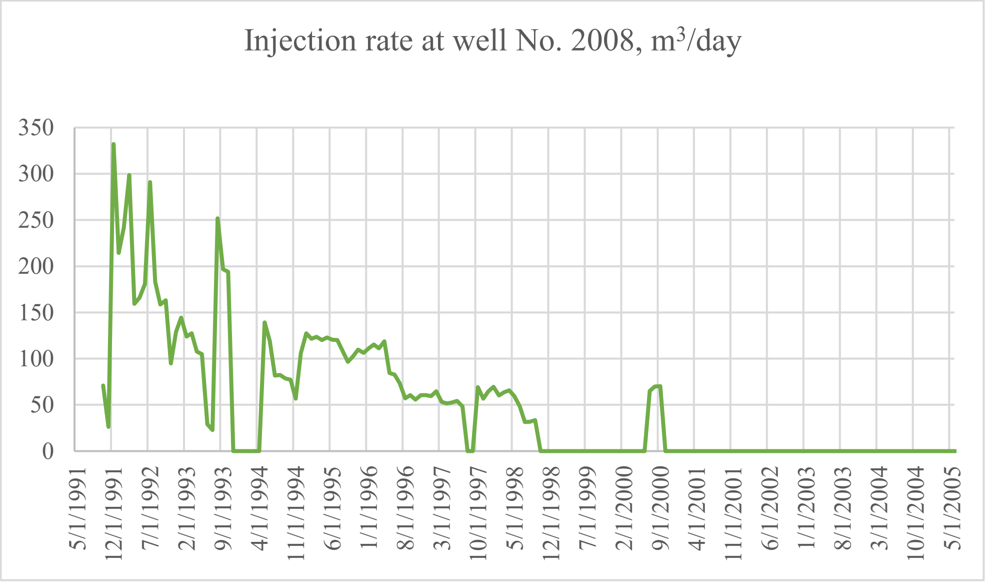

Fig. 4. Dynamics of injectivity at well No. 2008 of the Severo-Khokhryakovskoye field.

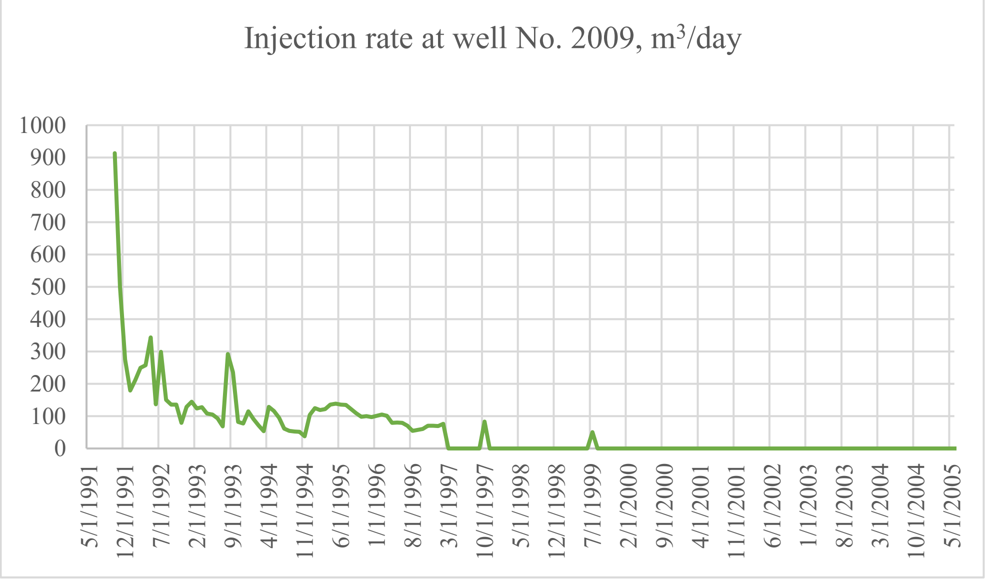

Fig. 5. Injectivity dynamics at well No. 2009 of the Severo-Khokhryakovskoye field.

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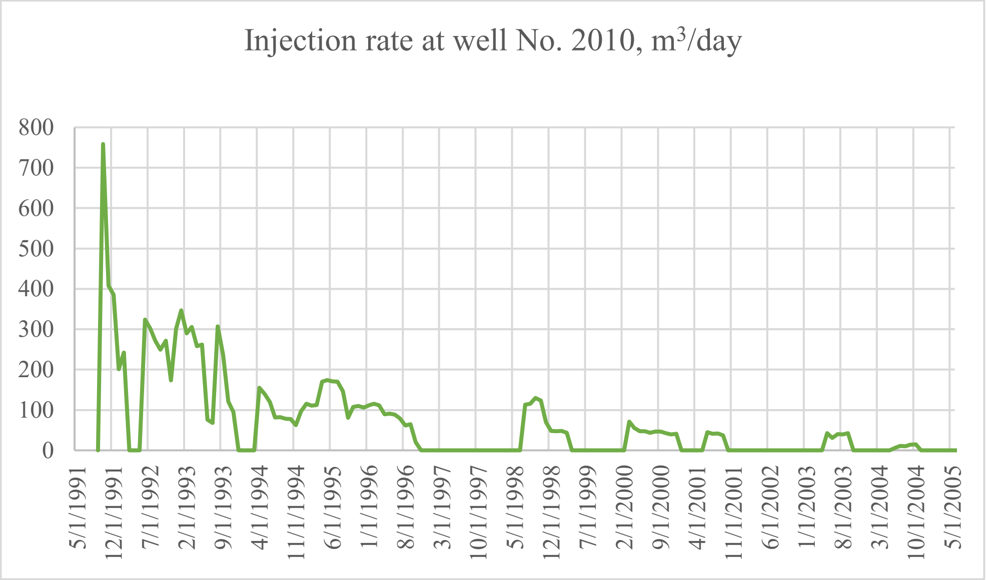

Fig. 6. Dynamics of injectivity at well No. 2010 of the Severo-Khokhryakovskoye field.

In the Bakhilovskoye field, out of 65 wells working to maintain reservoir pressure for the first 10 years after the launch of the RPM system (fresh water injection), 16 wells were stopped due to decline and 15 wells due to lack of injectivity.

At Verkhnekolik-Yeganskoye field, where fresh water was also used for the RPM system, injection wells worked quite stably, and there were no such reasons for well shutdowns as decline or lack of injectivity during the first 10 years of operation.

Let us consider another field - Kolik-Yeganskoye. Formation (Cenomanian) water from water intake wells is used to maintain reservoir pressure at the field. According to the core research data (Table 3) the swelling capacity of clay minerals is 1.91%, which is the third value from the table. According to Table 2, the average injectivity for the first year of operation was 172 m^3/day, after 5 years of operation of the same wells the average injectivity was 165 m^3/day, which indicates a fairly stable operation (Figures 7-8).

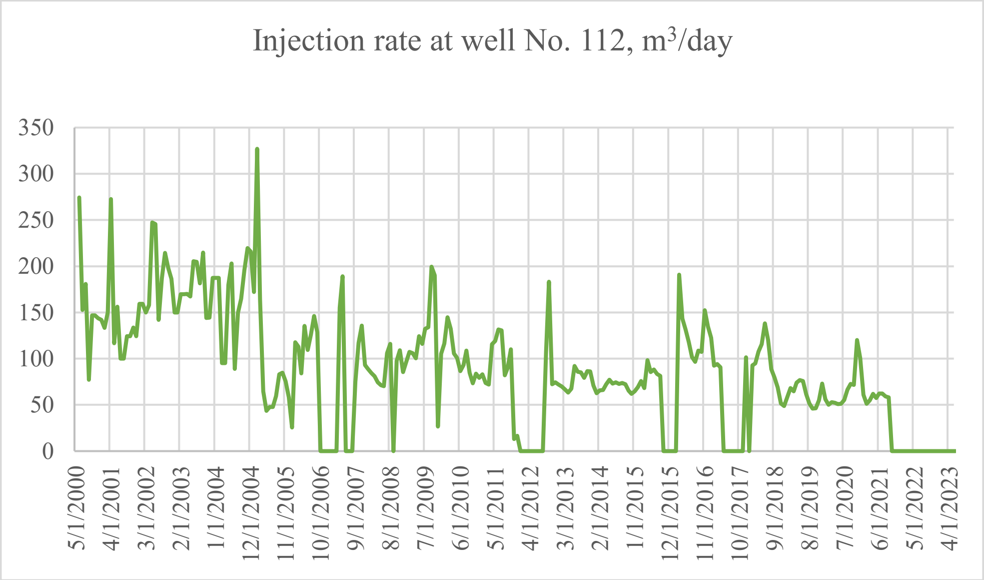

Fig. 7. Dynamics of injectivity at well No. 112 of the Kolik-Yeganskoye field.

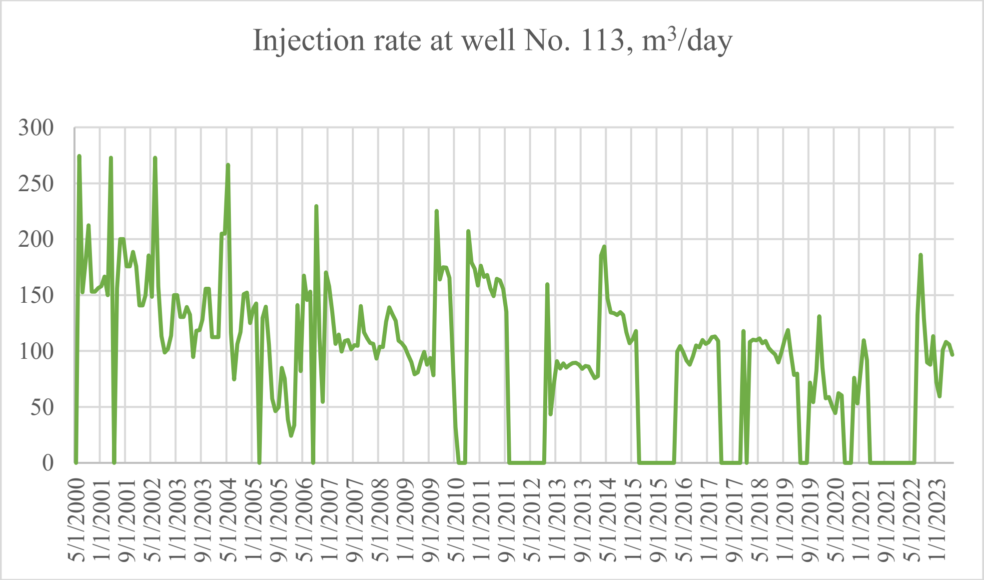

Fig. 8. Dynamics of injectivity at well No. 113 of the Kolik-Yeganskoye field.

4 Conclusions

Thus, based on the results analysis of field development, well operation mode and results of laboratory core research it was established that when selecting the injection agent, it is necessary to conduct core research to establish clay swelling and compare the data with similar formations in other fields, because fresh water injection can significantly complicate the process of oil recovery and lead to hydrocarbon losses.

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