Table 2 summarizes the details of fracture geometry obtained after simulation. All reported values refer to the entire fracture system at a model time of 720.00 min (end of stage 1). The values are reported for the end of the last pumping stage.

Table 2

Fracture Half-Length (m)	280	Propped Half-Length (m)	0
Total Fracture Height (m)	127	Total Propped Height (m)	0
Depth to Fracture Top (m)	2 094	Depth to Propped Fracture Top (m)	2 178
Depth to Fracture Bottom (m)	2 221	Depth to Propped Fracture Bottom (m)	2 178
Equivalent Number of Multiple Fracs	1,0	Max. Fracture Width (cm)	3,32
Fracture Slurry Efficiency**	0,00	Avg. Fracture Width (cm)	1,78

The fracture created in the well ‘231’ is considered optimal, since the fracture height covered a sufficient part of the pay zone and grows deeply into the zone, therefore, after the main treatment of hydraulic fracturing, an increase in the hydrocarbon access is assured hence increase in productivity.

It is obvious that the crack propagates in the area of minimal stress. The shape of the width profile shown is also stress dependent. Fractures tend to remain in vertical low stress regions that effectively “seal in” or “catch” the fracture and keep it from breaking into higher stress rock.

Staying in the formation is highly desirable, as staying in the zone of interest maximizes oil production and minimizes the waste of hydraulic fracturing energy on unproductive rocks.

The profile also shows that the proppant is concentrated in most of the fracture, which indicates the significant increase in permeability in the fracture zone, hence its conductivity, therefore, increases the flow of hydrocarbons into the wellbore and subsequently increases the efficiency of reservoir modeling and oil production.

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SOURCES OF CARBON DIOXIDE FOR MISCIBLE DISPLACEMENT ENHANCED OIL RECOVERY IN THE SIBERIAN REGION OF THE RUSSIAN FEDERATION

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Industrial applications of CO_2 have recently been considered as an environmentally attractive and economically viable alternative to enhancing oil recovery as well as reducing greenhouse gas emissions. Unlike other gases, CO_2 as a displacement agent produces a significant increase in the oil recovery coefficient. Under laboratory conditions, with unlimited miscibility, the oil displacement coefficient can reach 97%.

Carbon dioxide is a non-flammable greenhouse gas, chemically consisting of a carbon atom and two oxygen atoms with a molar mass of 44.01 g /mol and a concentration of 0.03-0.04% in air. Its density under normal conditions is 1.98 kg / m^3 (1.5 times heavier than air). Carbon dioxide dissolves in oil 4 -10 times better than in water. In 1m^3 of oil at a pressure of 10 MPa and a temperature of 27ºC, 250-300 m^3 of CO_2 is dissolved.

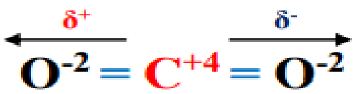

Fig.1 Molecular structure of carbon dioxide

Today, projects to increase oil recovery using CO_2 in Russia seem to be the most economically promising option for carbon capture and storage. Therefore, the assessment of the CO_2 sources that enable these projects to be implemented is of paramount importance. Sources of carbon dioxide can be divided into natural and man-made.

The Russian Federation as of 2017 had confirmed a total of four natural deposits of CO_2, namely; Astrakhan, West Astrakhan, Pomorskiy and North Gulyaev, with a total carbon dioxide reserve of 601.6 billion tons/m^3 and an average of 13.9 % concentration of CO_2.

In Western Siberia, as a rule, the concentration of carbon dioxide in oil associated gases does not exceed 1 %, but in some cases, there are accumulations with a significant content of carbon dioxide. Thus, the CO2 content at the Veselovskiy field reaches 85 %, at the Mezhovskiy field - 97 %, and at the Samutnel field-76.7%.

Anthropogenic CO_2 in Russia are mostly from the power plants (thermal power plants); cement plants; oil and gas processing plants; metallurgy enterprises; ammonia production factories, etc.

A study by concerned scientists USA in 2018, Russia as a country emitted 5% of the world's carbon dioxide emissions. Many industries have contributed to Russia's carbon dioxide emissions including but not limited to thermal power plants. It is estimated that the 71 coal-fired and 185 gas-fired power plants in Russia annually produce 297.1 and 309.6 million tons of CO2, which is enough for enhanced oil recovery in the 322 Russian oil fields.

Table 1

The largest thermal power plants in Russia with a capacity of more than 3000 MW

Thermal Power Plants	Capacity (MW)	Region	Fuel Used
Surgutskaya GRES-2	5650	Khanty-Mansiysk	Gas
Reftinskaya GRES	3800	Sverdlovsk region	Coal
Kostroma Power Plant	3600	Kostroma region	Natural gas
Permskaya GRES	3360	Perm Krai	Gas
Surgutskaya GRES-1	3333	Khanty-Mansiysk	Gaz
Ryazan GRES	3130	Ryazan region	Gas, coal

Surgutskaya GRES-2 is considered the most powerful thermal power plant in Russia and the fourth in the world in terms of installed capacity and annual generation. The reaction of natural gas with oxygen during oxidation, as shown in formula (1), forms carbon dioxide and water(steam).

The by-heat produced at the plant is used to provide heating for the cities of Tyumen and Surgut, and the resulting carbon dioxide is released into the atmosphere.

However, the huge amount of this greenhouse gas can be useful for numerous oil fields located in the close vicinity to increase oil recovery.

The natural gas used to fuel Surgut consists mainly of methane- 95%, ethane, propane, hydrogen, carbon dioxide and oxygen and other impurities by about 5%. The formula below shows the reaction between methane and oxygen

$$CH_4 + 2O_2 = CO_2 + 2H_2O \quad (1)$$

Calculation of the amount of CO_2 emitted daily by Surgut GRES-2 with a capacity of 5650 MW;

To obtain a capacity of 5650 MW = 536218 m^3/h of natural gas is burned.

If the natural gas with impurities is 100%, then the amount of pure CH_4 can be considered as:

If 100% of CH_4 = 536218 m^3/h;

$$95 = ? \Rightarrow \frac{95}{100} * 536218 = \mathbf{509407{,}1\ m^3/h}$$

The amount of pure CH_4 = **509407,1 m^3/h.**

$$\rho_{CH_4} = \frac{m_{CH_4}}{V_{CH_4}} \quad (2)$$

Where ρ – density of CH_4= 0,657 kg/m³, V – volume of gas= 509407,1 m³

Calculation of mass of CO_2 from the reaction equation (2), where one mole of methane is equal to one mole of carbon dioxide:

$$m_{CO_2} = \frac{m_{CH_4} * 44}{16} \Rightarrow m_{CO_2} = 920371{,}4 \text{ кг} = \mathbf{920{,}4\ т}$$

Surgut GRES-2 will emit **22.089 tons/day** of CO_2 for the intended EOR. Both Surgut GRES-1 and 2 together will emit **35104,2 tons /day.**

Simulation of CO2 injection in a reservoir X using Eclipse program

A three-dimensional (3D) model was constructed to analyze the behavior of CO_2 in Field X, as shown in Fig. 2. to predict and monitor the impact of CO_2 injection using a five-point model, where four injection (A, B, C, D) wells and one production (Well P) well.

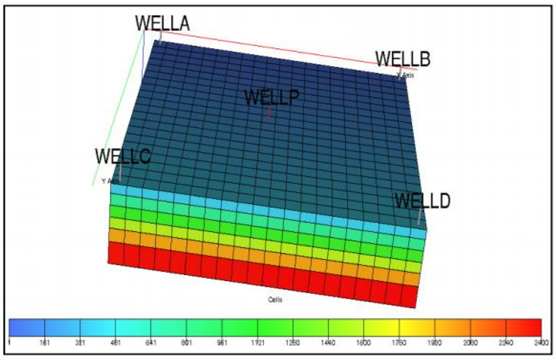

Fig.2 Five-point model with the location of wells

In this project, three connected parts were considered, without fluid injection ("Do Nothing"), with only CO_2 injection, and in the last section, CO_2 injection with subsequent water (CO_2-WAG). After modeling in the Eclipse 300, a comparison was made of their reservoir pressure, oil production rates in the fields, and water cut as shown in the following figures. Note that:

Figure A - Oil displacement efficiency (FOE) in the field with no EOR (DO-NOTHING), when injecting only CO_2 (CCO_2) and injection of CO_2 with water gas, (CO_2-WAG)

Figure B – Oil flow rate in the field with no EOR (DO-NOTHING), when injecting only CO_2 (CCO_2) and injection of CO_2 with water gas, (CO_2-WAG)

Figure C – Water Cut in the field with no EOR (DO-NOTHING), when injecting only CO_2 (CCO_2) and injection of CO_2 with water gas, (CO_2-WAG).

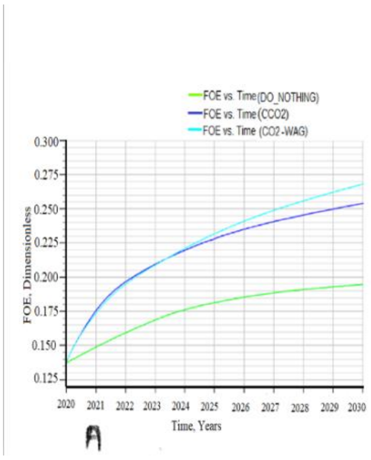

Fig. A

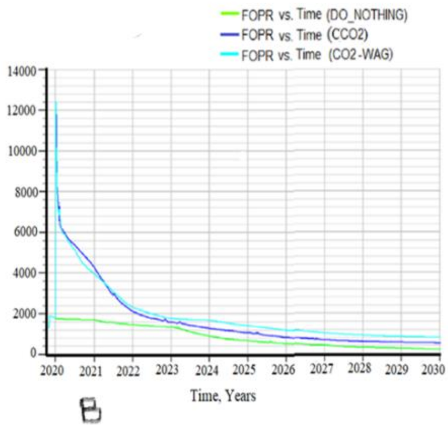

Fig. B

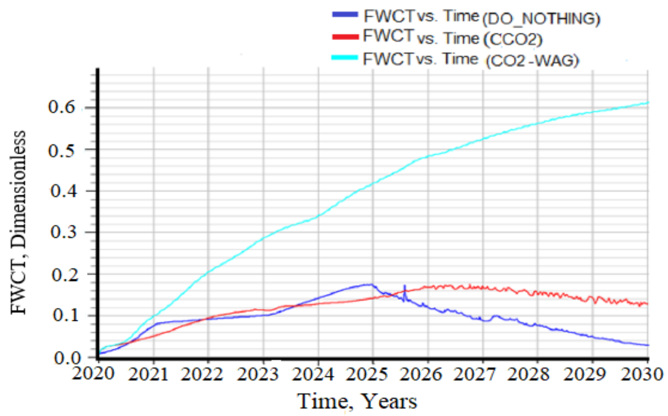

Fig. C

1. Figure A at the end of development shows that the efficiency of oil displacement (FOE) in the field for both CO_2 and CO_2 alternating water is significantly higher than primary production (without enhanced oil recovery). The oil displacement efficiency (FOE) for case 1 "(Do nothing) " reached 0.195, while CO_2, and CO_2 by subsequent water reached 0.255 and 0.270, respectively.
2. The oil production rate at the field as a function of time is shown in Figure B. It is observed that CO_2-WAG is more profitable than in all other cases with oil production of about 12400 STB/day in the first year of its use. CO_2 closely followed with 11800 STB/D. However, the case of (Do-nothing) was the least recorded with production of less than 2,000 barrels per day. A sharp decline in oil production was observed in both methods of enhanced oil recovery, with minor differences between them. This sharp decline can be the result of a variety of problems, such as an early breakout, a high skin factor, etc.
3. From figure C, the FWCT trend with only CO_2 was similar to the Do_Nothing case, but the rate of decline was much slower, reaching 0.13 at the end of the simulation. FWCT in the case of CO_2 - WAG increased at a higher rate than in the other two cases. However, it gave a manageable level of FWCT during the forecast period, thus not affecting the efficiency of the displacement process.

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