



## PROSPECTIVES FOR CO<sub>2</sub> ENHANCED AND INTENSIFIED OIL RECOVERY PROJECTS IN RUSSIAN FEDERATION

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### ABSTRACT

Worldwide practice, for rational CO<sub>2</sub> use, focuses on injection of this greenhouse gas for enhanced oil recovery (EOR) and intensified oil recovery (IOR). In total, as per year 2024, over 150 active CO<sub>2</sub> EOR &IOR projects are under run in various oil/gas producing countries, with USA leadership. These CO<sub>2</sub> technologies are at 9th maturity, technology stage readiness level, As for Russian territory, CO<sub>2</sub> technologies are at about 6-7 level. Despite positive Soviet Union CO<sub>2</sub> project design experience, recently, it is difficult to talk about design-to – project transformation. Because of different limitations, experience, sensitive consequences for carbon dioxide transportation and well injection into oil-bearing reservoirs, the oil recovery technologies with in- situ CO<sub>2</sub> generation, with no such limitations, and with proved positive field experience, seem as rather prospective ones, for their further optimization and scaling. Taking into account negative experience of large-volume areal CO<sub>2</sub> injection into oil-bearing reservoirs, with unplanned early CO<sub>2</sub> breakthroughs into production wells, unproductive losses of carbon dioxide, over corrosion of oil equipment and CO<sub>2</sub> environmental emission & pollution, it is reasonable to develop methods and technologies for maximal saturation of “oil-water-rock” system with carbon dioxide, with its minimal consumption, prevention of breakthrough to production well and all further negative consequences. To optimize numerous and multi-directional efforts, time, money expenses, it is proposed, to organize CO<sub>2</sub> EOR &IOR technologies single and united center, work program, structure and financing. The proposed article discloses numerous prospective ways for implementing CO<sub>2</sub> EOR &IOR projects in Russian oil fields.

**Keywords:** intensification of oil recovery; gaseous carbon dioxide; enhanced oil recovery; carbon footprint; carbon dioxide in-situ generation; tax incentives.

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### Introduction

Global ecological and especially climatic problems, being tied, through this or that way, with production and use of liquid and gaseous hydrocarbons, are in schedule of oil and gas industry. There is no doubt that modern climate change is mainly caused by emissions of greenhouse gases, including CO<sub>2</sub>, into the atmosphere. With signing UN frame convention Paris Agreement, Russian Federation took the obligation to reach, by year 2030, greenhouse emission not more, than 70% of its level in year of 1990. After approval of the “Russia Strategy for social and economic development, with low greenhouse gases emission by year of 2050”, the emission has to decrease with 60% against year 2019 and with 80% against year 1990. At already finished UN Baku climate COP-29 Conference, Russian delegation confirmed its participation at international climate initiatives and sounded Russia plans to reach carbon neutrality by year 2060.

It is known that worldwide practice, for rational CO<sub>2</sub> application, focuses on its use for enhanced oil recovery

(EOR), like other EOR methods [1-3] and for intensified oil recovery (IOR). These CO<sub>2</sub> technologies are at 9th maturity level, technology stage readiness, as shown in the table 1. It means, that the technologies have passed concept, hypothesis, laboratory test & verification stages. Also, pilot field application, technical basement and required equipment is available. So, CO<sub>2</sub> technologies are used in large scale and for big projects [4-55].

### Experience of CO<sub>2</sub> use for oil production

In total, as per year 2024, over 150 active CO<sub>2</sub> EOR &IOR projects are under run in various oil/ gas producing countries. USA is the leader here, with recovery of 94% of oil by use of CO<sub>2</sub> EOR &IOR technologies [30] (fig. 1).

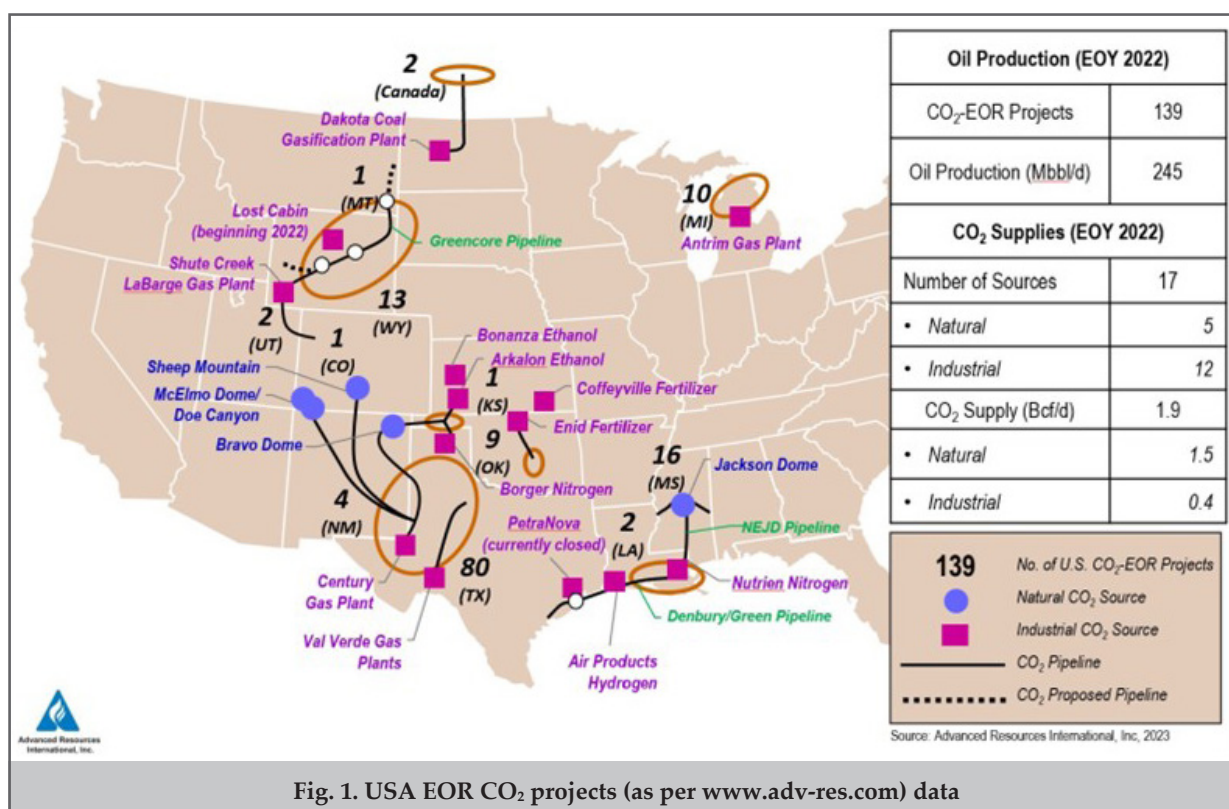
As per year 2022, there are 139 ongoing projects, with average 33.4 thous.tons oil production, at US territory. For this, 5 CO<sub>2</sub> natural sources of 42.7 mil.cu.m per day rate, and 12 industrial sources of 11.3 bil cu.m per day, are involved. Length of related CO<sub>2</sub> transportation pipelines is over 8000 km. US ministry of energy study [33], of year of 2022, indicated that CO<sub>2</sub> EOR technologies can provide up to 30-40% of all crude oil in USA within next dozens of

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Table 1

| Technology readiness levels (TRL) ( <a href="https://docs.cntd.ru/document/1200158331">https://docs.cntd.ru/document/1200158331</a> ) |                                                                                               |
|---------------------------------------------------------------------------------------------------------------------------------------|-----------------------------------------------------------------------------------------------|
| TRL 1                                                                                                                                 | Main technology principles are studied and published                                          |
| TRL 2                                                                                                                                 | Concept, for technology and/ or its use, are formulated                                       |
| TRL 3                                                                                                                                 | Critical functions and/or characteristics are verified with analytical and experimental ways  |
| TRL 4                                                                                                                                 | Components and /or model are tested in laboratory conditions                                  |
| TRL 5                                                                                                                                 | Components and /or model are tested in conditions, close to real ones                         |
| TRL 6                                                                                                                                 | Technology system/ subsystem or prototype are demonstrated in conditions, close to real ones. |
| TRL 7                                                                                                                                 | Technology prototype is demonstrated in working conditions                                    |
| TRL 8                                                                                                                                 | Real technology system is finalized and qualified during its tests and demonstration          |
| TRL 9                                                                                                                                 | Real technology system is proved with successful use (achievement the goal)                   |

Fig. 1. USA EOR CO<sub>2</sub> projects (as per [www.adv-res.com](http://www.adv-res.com)) data

years. Most of highly efficient projects are ones with miscible CO<sub>2</sub> displacement. Mostly sounding CO<sub>2</sub>-EOR projects are: SACROC (since 1972) with additional oil production of 28.3 thous.bbl per day [48], Wasson-Denver (1983) with additional oil production of 24.4 thous.bbl per day and Yates (2004) with additional oil production of 15 thous.bbl per day.

Starting from years 2011-2012, US oil industry and Ministry for Energy, began renaming and transforming CO<sub>2</sub>-EOR projects into CCUS (carbon capture, use, and storage) ones [56-64], so to recover more oil through reinjection of CO<sub>2</sub> from oil production wells.

Main drivers, for development of CO<sub>2</sub>-EOR и CCUS projects in USA, are:

- availability of CO<sub>2</sub> natural sources
- accumulated, since 1970s, experience of implementing large CO<sub>2</sub>-EOR projects construction since the 1970s of a special network of long pipelines for the transportation of CO<sub>2</sub>;
- use of special corrosion-resistant field equipment and materials for working with CO<sub>2</sub>;
- reduction in costs and increased efficiency of oil

extraction due to technological progress;

- use of the mechanism of climate projects that reduce the carbon footprint;
- government support for CCUS programs and projects for the use of CO<sub>2</sub> to enhance oil recovery;
- a number of financial incentives that have led to increased investment in projects with CO<sub>2</sub> technologies.

In Russia, technologies, for enhanced oil recovery with CO<sub>2</sub>, are at approximately level 6-7 of technological maturity, despite the positive experience that has existed since the Soviet era and the prepared projects for pilot industrial work on area injection of CO<sub>2</sub> at the Sergeyevskoye, Radayevskoye, Kozlovskoye and other fields [7-9]. The main reasons, for the technologies not being at higher levels, were the lack of natural sources of CO<sub>2</sub> and the permanent change in the economic situation in Russia since the end of the 1980s. An important indicator of the technological success of CO<sub>2</sub> – technologies for enhancing oil recovery is the additional oil production per 1 ton of injected CO<sub>2</sub>. Table 2 shows the statistics of the specific efficiency of area injection of CO<sub>2</sub>

**Table 2**

**Specific efficiency of area injection of CO<sub>2</sub> into injection wells, with oil recovery through production wells**

| Source                                                                   | Object, field      | Quantity of CO <sub>2</sub> used, tones | Additional oil recovery (AOR), tones | AOR per one ton of CO <sub>2</sub> |
|--------------------------------------------------------------------------|--------------------|-----------------------------------------|--------------------------------------|------------------------------------|
| Kalinin S.A., Morozyuk O.A. [7]                                          | Nagylengel         | 191466000                               | 34340000                             | 0.18                               |
|                                                                          | Bati Kozluca       | 1980                                    | 850                                  | 0.43                               |
| Afanasyev S.V., Volkov V.A. [8]                                          | Radaevskoye        | 787200                                  | 218000                               | 0.28                               |
|                                                                          | Kozlovskoye        | 110100                                  | 12600                                | 0.11                               |
|                                                                          | Sergeevskoye       | 73800                                   | 17700                                | 0.24                               |
| Ibatullin R.R. [9]                                                       | Permian Basin, USA |                                         |                                      | 0.48                               |
|                                                                          | Elabuzhskoye       |                                         |                                      | 0.33                               |
| The survey of U.S. CO <sub>2</sub> enhanced oil recovery (EOY 2022) [33] | US average         |                                         |                                      | 0.417                              |
| A.T. Zaripov and others [10]                                             | Biklyanskoye       | 5020000                                 | 247000                               | 0.05                               |
|                                                                          |                    | 777000                                  | 51000                                | 0.066                              |
|                                                                          |                    | 2201000                                 | 141000                               | 0.064                              |

published in open sources.

Unfortunately, there are no details in the open press about the successful implementation of pilot industrial projects using CO<sub>2</sub> in Russia and a detailed analysis of the results.

The current climate agenda, the need to capture CO<sub>2</sub> generated during fuel combustion or in industrial technological processes (exhaust gases – EG), have led to increased attention from the interested expert community to the injection of CO<sub>2</sub> into depleted oil reservoirs as one of the main possible solutions to the problem of reducing the carbon footprint. However, for the successful implementation of these projects at oil fields, Russian oil and gas producing and scientific and technological companies need to solve a number of technological, economic and regulatory issues.

As an example, we can cite preliminary project estimates for the area injection of a large quantity (500,000 t/year) of a mixture of exhaust gases with 80% CO<sub>2</sub> content into oil production facilities in the Perm region, the analysis of which revealed the main list of difficulties standing in the way of the successful implementation of these projects today.

EG component composition (table 3) influences the decisions on technological schemes for EG transportation and use for of EOR and IOR projects.

EG contains hydrogen and other components, with 1.71 mass % of hydrogen in mole fractions being 24.4%. Research, by many authors, shows that the presence of hydrogen in a mixture of gases with CO<sub>2</sub> significantly changes the properties of this mixture. All this can affect both the results of laboratory studies on miscibility and filtration, and the conclusions on technical and economic solutions for the transportation, compression and injection of EG into operational facilities intended for this purpose.

The gaseous phase of transportation and injection of the EG mixture, without its preliminary preparation chosen by the designers, predetermines high investment costs – about 90% for gas compressor stations and a pipeline for CO<sub>2</sub>. Gas compressor stations require an increase in electrical capacity, expensive annual service and spare parts.

Options, for the possible implementation of CO<sub>2</sub> injection, were calculated by specialists from the design organization. Integrated geological and hydrodynamic model ensured preliminary technical and economic assessments.

The main results of the preliminary estimates of the designers:

- significant increases in the flow rates of liquid from producing wells and large values of additional oil production are shown;
- additional oil production per 1 ton of injected EG is 0.05-0.098 tons, which is an order of magnitude less than the values obtained from the analysis of world experience typical for area injection (0.28-0.48 tons/ton);
- the majority of 70-80% of the injected EG breaks through to the producing wells and is collected in a mixture with associated hydrocarbon gas;
- more than 80% of the EG subject to disposal is ultimately buried in the depleted gas reservoir.

In addition, accelerated corrosion of oilfield equipment unpreparedness of the existing infrastructure and well equipment, for working with CO<sub>2</sub>, are noted.

All project options with CO<sub>2</sub> injection yielded negative values of net present value (NPV). Risks of project deterioration are expected, with volatility and changes in the energy and currency markets.

As can be seen from table 4, the assessment of the base

**Table 3**

**Example of the component composition of the exhaust gas mixture (EG)**

| Component       | %mas. | %mol.   |
|-----------------|-------|---------|
| Hydrogen        | 1.71  | 24.3974 |
| Methane         | 7.43  | 13.3211 |
| Ethane          | 0.26  | 0.2487  |
| Propane         | 0.75  | 0.4892  |
| Iso-butane      | 0.32  | 0.1584  |
| N-butane        | 0.74  | 0.3662  |
| Butenes         | 0.02  | 0.0103  |
| Iso-pentane     | 0.26  | 0.1036  |
| N-pentane       | 0.05  | 0.0199  |
| CO              | 8.53  | 8.7591  |
| CO <sub>2</sub> | 79.58 | 52.0093 |
| C6+             | 0.35  | 0.1168  |

case, with water injection without using CO<sub>2</sub> injection, is characterized by a positive NPV = 495 million rubles and a fairly high recovery factor = 44.5%. The project, with area injection of CO<sub>2</sub>, is characterized by large initial capital costs (about 14 billion rubles) for compressor equipment, construction of CO<sub>2</sub> pipelines, modernization of existing equipment and wells for working with CO<sub>2</sub>. The calculation, from the feasibility study for area injection of CO<sub>2</sub> at the selected pilot site, showed the unprofitability of such a project, with a negative NPV = minus 8369 million rubles.

The implementation of such project is possible only with the inclusion of government regulation measures, in the form of tax preferences – a temporary reduction in the mineral extraction tax rate (MET), which will allow the project to be transferred to a profitable category. As a result, the budget

and enterprise revenues will grow, and the final oil recovery factor will increase.

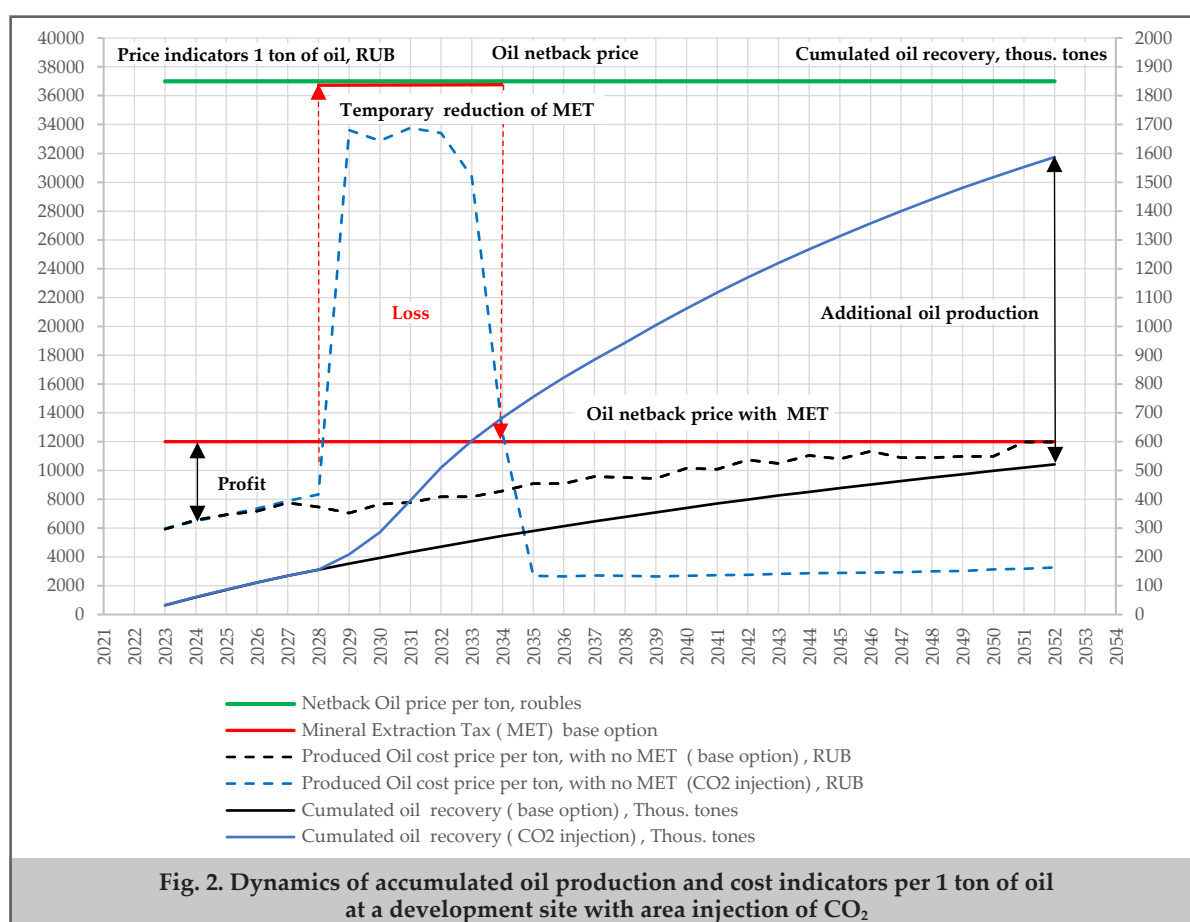
This project can be transferred to the category of profitable ones by using a tax maneuver - temporarily zero the mineral extraction tax rate for the first seven years of implementation to compensate for high initial capital costs, while the cost of producing 1 ton of oil is expected to increase several times over 6 years to 33,000 rubles, but then decrease below the initial level to 2,500 rubles, as shown in figure 2. As a result, the implementation of the project will allow for additional budget revenue of 11.669 million rubles, the enterprise's net profit will be 1.939 million rubles and the recovery factor will increase to 50.4%.

As can be seen from the graph in figure 2, the cost of producing one ton of oil, without the mineral extraction

Table 4

Evaluation of the indicators of the CO<sub>2</sub> injection project options

| Indicator                                 | Basic option (water injection) | Option to maintain the mineral extraction tax rate | Option to reduce the mineral extraction tax rate (MET) during the first 7 years |
|-------------------------------------------|--------------------------------|----------------------------------------------------|---------------------------------------------------------------------------------|
| Years of implementation                   | 2029-2052                      | 2029-2052                                          | 2029-2052                                                                       |
| Netback oil price, RUB                    | 37000                          | 37000                                              | 37000                                                                           |
| MET rate, RUB                             | 25000                          | 25000                                              | 25000                                                                           |
| Number of injection wells                 | 7                              | 9                                                  | 9                                                                               |
| Number of production wells                | 39                             | 39                                                 | 39                                                                              |
| Incremental oil production, thousand tons | 521                            | -                                                  | 1587                                                                            |
| ORI, %                                    | 44.5                           | -                                                  | 50.4                                                                            |
| MET, million RUB                          | 13025                          | -                                                  | 24694                                                                           |
| Net profit (10%), million RUB             | 495                            | -8369                                              | 1939                                                                            |



tax, is a unified standardized indicator for monitoring the profitability of developing an operational facility. The indicator can be used for tax benefits justification.

A temporary reduction in the mineral extraction tax rate can be an effective tool for transforming unprofitable projects into profitable ones. It will ultimately stimulate the introduction of innovative EOR and IOR technologies, and will allow for additional oil production, additional budget revenues, and an increase of profitable development period and the final oil recovery factor.

To monitor the project's exit from the profitability zone, it is recommended to use the scheme presented in figure 2 using actual data: netback oil prices, oil production costs, mineral extraction tax for the billing period – month, quarter, year.

### Cyclic CO<sub>2</sub> injection

Separately, it is necessary to mention about processing producing wells, based on cyclic CO<sub>2</sub> injection (HUFF&PUFF) technologies [6,8,9,41]. The technologies are tested, for a wide range of geological, field conditions and industrially implemented at the world level technologies of intensification of oil recovery. As a rule, to increase the efficiency of the technology, the amount of CO<sub>2</sub> per well operation, its aggregate state, the number of injection cycles, the pause time, after injection and before for flow back, should vary. A mandatory condition, for the implementation of the technologies, is the availability of liquid carbon dioxide delivered by tank trucks to the well pad and a high-pressure pump.

Pilot industrial tests of the technology, conducted by RITEK LLC, allowed to increase the flow rate of wells, with high-viscosity oil, as well as to put previously idle wells into operation. According to the data published in [6], when injecting 160-300 tons of CO<sub>2</sub> per well, high values of additional oil of 657-2070 tons were obtained, with additional oil per one ton of injected CO<sub>2</sub> are 3.3-11.3 tons/

t. This significantly exceeds the values of world indicators, including ones for area injection of CO<sub>2</sub>. Unfortunately, the article does not provide data on the amount of CO<sub>2</sub>, released from the wells after startup, the presence of ASPD deposits on pumping equipment. As well, as estimates on well production and corrosion acceleration, not only just after technology use. This technology does not belong to the class of enhanced oil recovery technologies, is not suitable for the utilization of large quantities of CO<sub>2</sub>. Its use is reasonable for the restoration or increase in the productivity of production wells in certain geological and physical conditions.

### Carbon capture, use, and storage (CCS/CCUS) projects

As an advanced project for carbon capture, use, and storage (CCS/CCUS), we would like to cite the project, implemented by Tatneft near the Nizhnekamsk industrial zone [12]. The flue gases, emitted by the Nizhnekamsk CHPP-2 and the TANECO oil refinery, are planned to be captured and separated, and the CO<sub>2</sub> is planned to be liquefied and injected into underground formations. The main volume of captured greenhouse gases is planned to be placed in underground reservoirs. The company received permission from the State Commission of the Federal Agency for Subsoil Use (Rosnedra) to conduct pilot projects on injecting CO<sub>2</sub> into a deep aquifer at a subsoil site in the Nizhnekamsk industrial zone (part of the Volga-Ural oil and gas province). Based on the results of geological and hydrodynamic modeling at the stage of geological study and assessment of the suitability of this subsoil area for the construction of underground structures for the purpose of placing carbon dioxide, it was established that the area is capable of accommodating over 300 million tons of greenhouse gases.

Part of the CO<sub>2</sub> is planned to be used to enhance oil recovery and increase well flow rates. To date, as part of pilot

Specific efficiency of cyclic injection into production wells (HUFF&PUFF)

Table 5

| Technology                                                                        | Object and oil viscosity              | Quantity of CO <sub>2</sub> used, tones | Additional oil recovery (AOR), tones | AOR per one ton of CO <sub>2</sub> |
|-----------------------------------------------------------------------------------|---------------------------------------|-----------------------------------------|--------------------------------------|------------------------------------|
| Darishchev V.I., Kharlanov S.A., Babinets Yu.I., Zinoviev A.V., Antonova D.O. [6] | Maryinskoye field e, 795 mPa·s        | 300                                     | 1000                                 | 3.3                                |
|                                                                                   | Strelkovskoye field, 595 mPa·s        | 160                                     | 1800                                 | 11.3                               |
|                                                                                   | Strelkovskoye field, 595 mPa·s        | 200                                     | 657                                  | 3.3                                |
|                                                                                   | Aksyenovskoye field, 209-403 mPa·s    | 202                                     | 2070                                 | 10.2                               |
|                                                                                   | Vozdvizhenskoye field 209-403 mPa·s   | 207                                     | 1490                                 | 7.2                                |
|                                                                                   | Aksyenovskoye field, 209-403 mPa·s    | 200                                     | 1260                                 | 6.3                                |
|                                                                                   | Vozdvizhenskoye field 209-403 mPa·s   | 200                                     | 1066                                 | 5.3                                |
|                                                                                   | Kutuzovskoye & Maiorovskoye fields    | 379                                     |                                      |                                    |
| Kalinin S.A., Morozyuk O.A. [7]                                                   | Halfmoon field 118 mPa·s              | 520                                     | 203                                  | 0.39                               |
|                                                                                   | Cumurlu field, well. 11 415–705 mPa·s | 1504.8                                  | 1223.9                               | 0.81                               |
|                                                                                   | Cumurlu field, well. 22 415–705 mPa·s | 1064.25                                 | 1958.4                               | 1.84                               |
| Ziganshin R.Sh. [11]                                                              | For Russia                            |                                         |                                      | 5.26                               |
|                                                                                   | For USA                               |                                         |                                      | 0.81                               |
|                                                                                   | For China                             |                                         |                                      | 1.45                               |
|                                                                                   | Trinidad and Tabago                   |                                         |                                      | 0.12                               |

projects, Tatneft has become the first in the country to use the technology of injecting a large volume of carbon dioxide into a highly watered well. The technology has been tested on the Bobrikov horizon of the Biklyanskoye field. 940 tons of CO<sub>2</sub> were injected into the well in test mode. According to the monitoring results, the current oil recovery factor has increased by 15%.

Hydrodynamic modeling has shown, that replicating the technology at this field will allow using up to 100 thousand tons of carbon dioxide annually.

The total cost of selecting and developing technologies, for enhancing oil recovery using CO<sub>2</sub>, will be determined by both data on the specific efficiency of the technologies and the costs of preparing, conducting laboratory studies, pilot and industrial work.

### In-situ CO<sub>2</sub> generation for EOR and IOR projects

In the absence of accessible sources of CO<sub>2</sub> and the possibility of its injection from surface communications, different technology for carbon dioxide in-situ generation, including ones with chemical reactions when contacts of certain chemicals water solutions [4, 14,17, 19-26]. From aqueous solutions of chemical reagents, injected into the reservoir, and due to their stoichiometric reaction, CO<sub>2</sub> is generated, like a pseudo-boiling gas-liquid mixture.

The emergence and development of such technologies is associated with the known technological difficulties and disadvantages of CO<sub>2</sub> injection: from surface communications, associated with the need for special pipelines, mobile tanks for transport, downhole equipment for CO<sub>2</sub> injection under pressure, in conditions of rapid corrosion wear, metal destruction and the risk of explosions in the workplace.

The use of in-situ carbon dioxide generation technologies is not accompanied by the listed difficulties and disadvantages [19-27].

Technologies for in-situ generation of CO<sub>2</sub> using gas-

forming and gas-generating agents have passed the stages of laboratory research (fig. 3), pilot-industrial (table 6), industrial testing and are at the 9th level of technological readiness (TRL 9).

In general, when carbon dioxide contacts displaced oils in reservoirs, such processes take place, as forced displacement of oils by CO<sub>2</sub>, early breakthroughs of carbon dioxide to production wells and a sharp decrease of the efficiency of displacement, extraction of part of the oil by CO<sub>2</sub>, saturation of oil, formation water and reservoir rock with CO<sub>2</sub>, independent filtration of additional volumes of film and mobile oils with dissolved CO<sub>2</sub>, due to the acquisition and increase in mobility, recovery of carbon dioxide from production wells, with the need for its further disposal. Comparing the technologies of enhanced oil recovery, by large-volume injection of CO<sub>2</sub> into injection wells, cyclic injection into production wells (HUFF&PUFF), as well as in-situ generation of carbon dioxide, it should be noted that in the third case, early breakthroughs of large volumes of carbon dioxide to production wells and the need for its further utilization are not observed.

A preliminary comparison of the specific efficiency of technologies with CO<sub>2</sub> (the amount of additional oil per unit mass of injected or generated carbon dioxide) shows sufficient competitiveness of technologies of both cyclic injection and in-situ generation of CO<sub>2</sub>.

In this regard, it is advisable to continue work on clarifying the technological efficiency of technologies of cyclic injection and in-situ generation of CO<sub>2</sub> for various geological and industrial conditions.

Methodological recommendations [65] for substantiating the suitability of subsoil areas for the construction and operation of underground structures not associated with the extraction of minerals, for the purpose of placing carbon dioxide regulate the conditions in which one or another technology can be applied.

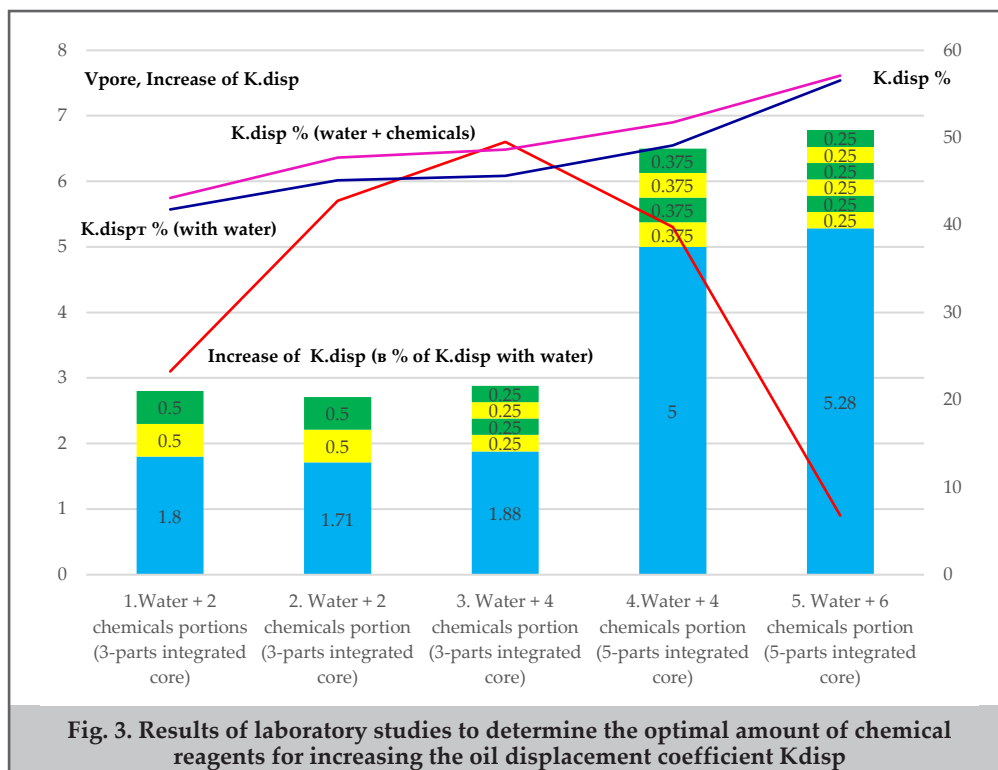


Table 6

Results of pilot and industrial tests of in-situ CO<sub>2</sub> generation technology

| Object for pilot industrial operations          | Year      | Number of treated wells | Volume of aqueous solutions of chemical reagents per one injection well, m <sup>3</sup> | Additional oil production, thousand tons | Time of effect evaluation, months | Oil production growth, % | Number of covered production wells |
|-------------------------------------------------|-----------|-------------------------|-----------------------------------------------------------------------------------------|------------------------------------------|-----------------------------------|--------------------------|------------------------------------|
| AV1-3 of Samotlorskoye oil field, Russia        | 1999      | 13                      | 180                                                                                     | 18                                       | 9                                 | 22                       | 62                                 |
| YuV1(2) of Novopokurskoye oil field, Russia     | 2001      | 3                       | 160                                                                                     | 3                                        | 9                                 | 19                       | 10                                 |
| Chzhunyuan oil field China                      | 2002      | 18                      | 190-330                                                                                 | 9                                        | 6                                 | 16                       | 43                                 |
| Muskogee oil field, USA                         | 2009      | 3                       | 98                                                                                      | 0.42                                     | 1                                 | 45                       | 14                                 |
| Vatiganskoye oil field, Russia                  | 2010      | 5                       | 495                                                                                     | 5.6                                      | 6                                 | 12.6                     | 21                                 |
| Bokhai Bey oil field, China                     | 2009-2010 | 2                       | 345                                                                                     | 5.9                                      | 4                                 | 22                       | 8                                  |
| BS10 of Tevlinsko-Russkinskoye oilfield, Russia | 2022-2023 | 3                       | 327-660                                                                                 | 3                                        | 8                                 | 13                       | 17                                 |

### Conclusions

1. Because of available technological, economic limitations, for carbon dioxide transportation and well injection into oil-bearing reservoirs, then limited native experience of large scaled projects for areal CO<sub>2</sub> injection, the oil recovery technologies with in-situ CO<sub>2</sub> generation, which do not have such limitations, and with positive proved field experience, seem to be as most prospective ones, for their further optimization and scaling.

2. Taking into account negative experience of large-volume areal CO<sub>2</sub> injection into oil-bearing reservoirs, with unplanned early CO<sub>2</sub> breakthroughs into production wells, unproductive losses of carbon dioxide, over corrosion of oil equipment and CO<sub>2</sub> environmental emission & pollution, it is reasonable to develop methods and technologies for maximal saturation of "oil-water-rock" system with carbon dioxide, with its minimal consumption, prevention of breakthrough to production well and all further negative consequences.

3. Because of numerous, multi-directional, separate, time and money consuming efforts for research, development, tests, implementation, optimization of native CO<sub>2</sub> oil recovery technologies, it is proposed, for such purposes, to organize single and united center, work program, structure and financing. With additional state support, all interested commercial, industry, science, educational, other organization could participate at such program. To initiate, start and coordinate the program, it is necessary to arrange a working group of respectable experts and other representatives from all listed organizations.

4. It is necessary to wider use of CO<sub>2</sub> slugs area injection and oil reservoir "saturating" strategy, which will prevent a large scaled CO<sub>2</sub> breakthrough, where water and slugs injection will allow to increase reservoir pressure and achieve more miscibility of CO<sub>2</sub> with displaced oil.

5. So, reliable, effective implementation of CO<sub>2</sub> related projects and technologies, to increase oil recovery in Russian Federation, is possible, when following conditions are met:

- further pilot industrial tests, for area injection of carbon dioxide, which will increase the level of technological maturity and significantly reduce the risks of large-scale industrial implementation of the technology;

- wider use the mechanism for implementing climate projects in accordance with the Federal Law of 02.07.2021 No. 296-FZ "On Limiting Greenhouse Gas Emissions" with the implementation of carbon units.

- in the absence of CO<sub>2</sub> natural sources, it is necessary to use CO<sub>2</sub> containing smoke and exhaust gas mixtures, from fuel combustion and industrial processes;

- use the CCUS technology process: capturing a gas mixture, with its further separating and using CO<sub>2</sub> for EOR, and then burying the remaining gas mixture. It is necessary to separate the exhaust gas flows using cryogenic technologies into two flows: the first one -for obtaining liquefied CO<sub>2</sub> for EOR technologies, and the second one-containing a gaseous mixture of the remaining gases - for disposal in underground structures, in order to place carbon dioxide in the immediate vicinity of the emission source. This solution must be flexible with the ability to redistribute flows, if necessary;

- it is reasonable to use liquefied CO<sub>2</sub> for transportation via pipelines and injection into oil reservoirs;
- it is reasonable to define in-situ and infrastructural objects, taking into account the conformity of the reservoir pressure with the minimum miscibility pressure of CO<sub>2</sub> and oil, as well as the readiness of the infrastructure and equipment to work with carbon dioxide;
- for transforming unprofitable projects into profitable ones, to use- as an effective tool- a temporary reduction of the mineral extraction tax rate. This ultimately will stimulate the implementation of innovative EOR and IOR technologies, and will allow additional oil production, budget revenues, increase of the profitability period and the final oil recovery factor;
- the solution to the problem, of utilizing large amounts of CO<sub>2</sub> to reduce the carbon footprint, is primary seen with measures in the Methodological Recommendations for Justifying the Suitability of Subsoil Areas for the Construction and Operation of Underground Structures Not Related to Mineral Extraction, for the Purpose of Placing Carbon Dioxide (PSRUG) [62]. The injection of large volumes of CO<sub>2</sub> into oil-bearing objects, is behind the scenes, for now, and awaits its decision.

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