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Hydrodynamic Modeling and Evaluation of Partial Substitution of Cushion Gas During Creation of Temporary Underground Gas Storage in an Aquifer

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A B S T R A C T

The flaring of associated gas remains a problem for oil and gas fields that are difficult to access and remote from the infrastructure. Active development of oil and gas production in Eastern Siberia has led to the fact that transportation capacities cannot keep up with field development. Increased flaring of associated gas leads to a significant increase in greenhouse gases such as carbon dioxide and methane. A possible solution to this problem is to store gas in the aquifer of the field for its future sale and monetization through the main gas pipeline. This paper analyzes the main technologies of associated gas utilization and reveals the problem of remoteness from gas transportation infrastructure of hard-to-reach fields. An effective technology to solve this problem is the creation of temporary underground storage of associated gas in the aquifer of the field. The results of hydrodynamic modeling of realization of this technology with partial replacement of cushion gas showed that joint injection of carbon dioxide and nitrogen before hydrocarbon gas allows to increase the ratio between produced and injected gas, which indicates its greater efficiency. It is recommended that in order to implement the technology, when selecting a geological injection site, to focus on aquifers with a temperature above 31.2°C, which will allow carbon dioxide to remain in a supercritical state in reservoir conditions.

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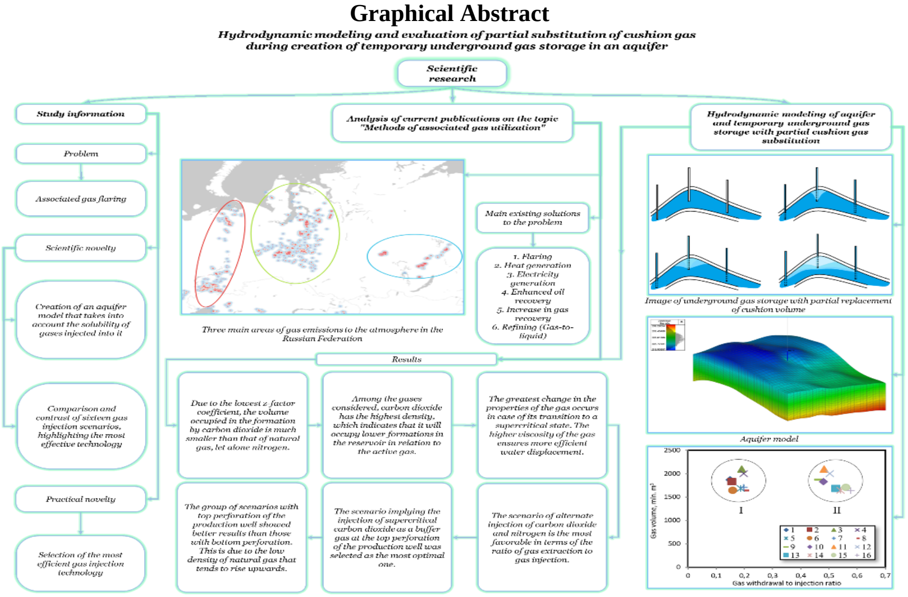
Graphical Abstract



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1. INTRODUCTION

Energy, raw materials-related. and environmental issues are currently acquiring a global scale, which determines the relevance of the search for technical, organizational, and economic solutions for the rational use of all kinds of natural energy resources, including associated gas (1).

Associated gas (AG) is a gaseous mixture consisting of methane, ethane, propane, butane, and other hydrocarbon compounds. Associated gas flaring and emissions into the atmosphere result in a marked increase in greenhouse gases (2). According to the International Energy Agency (IEA), emissions from the world's energy sector are steadily high. In 2022, 37 Gt of carbon dioxide was recorded, which is 1% above the 2019 level (3). It is also worth noting that a fast and sustained reduction in methane emissions is key to combating global warming (4). Gas flaring generates more than 500 million tons of CO_2-equivalent greenhouse gases per year, including both CO_2 and methane emissions.

Over the past nine years, the top seven gas-flaring countries have been Russia, Iraq, Iran, the United States, Algeria, Venezuela, and Nigeria (5). These countries produce 40% of the world's oil annually but account for about two-thirds of the world's associated gas flaring (5).

Russia topped the world ranking of associated gas flaring countries in 2020. At the same time, different trends were observed in different regions of the country: a significant increase in associated gas flaring utilization in Eastern Siberia along with a significant flaring reduction in the Khanty-Mansy and Yamalo-Nenets Autonomous Areas in Western Siberia. The Global Methane Tracker study used satellites to record active outbreaks of gas emissions worldwide from January through August 2022. By superimposing the obtained maps on each other, one can identify three main gas emission zones in the Russian Federation: the coal industry zone and oil and gas zones in Western and Eastern Siberia (Figure 1). Although satellite coverage of Russia is low, it is enough to give an estimate of major emission sources.

Although over 54% of all flared associated gas is located within a radius of 20 km from the nearest pipeline, at least 46% remains, which includes most of the remote and hard-to-reach fields. Active development of oil and gas production in remote regions contributes to an increase in the amount of gas flared (6).

Currently, when natural gas prices are near their all-time highs (7), gas flaring not only exerts a negative impact on climate change and human health but also is an enormous waste of money (8). Sun et al. (9) highlighted two main directions for reducing methane emissions: controlling natural gas demand for future emissions and introducing cost-effective reduction technologies for current emissions.

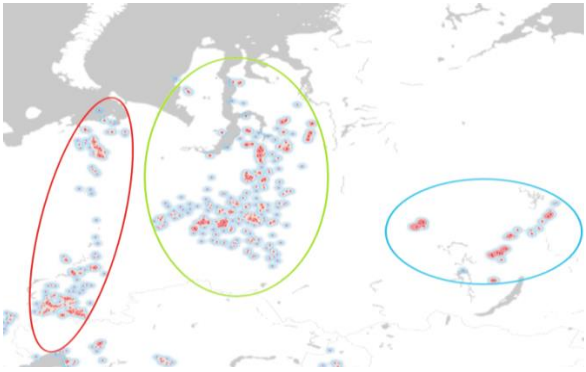

Figure 1. Red zone - coal industry in the Urals, green zone - Western Siberia, blue zone - Eastern Siberia

The main solutions currently implemented at gas fields include:

1. Gas flaring: large energy losses with significant environmental impacts. This practice is still common due to the large volumes of natural gas in the subsoil and its relatively low price (10). According to Federal Law No. 296 "On limiting Greenhouse Gas Emissions" of December 30, 2021, conditions must be created to promote sustainable and balanced development of the country's economy in the context of reducing greenhouse gas emissions.

2. Heat generation: providing heat supply to production buildings and structures of the field, heating of auxiliary and social facilities. Heat-generating units can also be used for heating oil emulsions and formation water.

3. Electricity generation: using gas-turbine or gas-piston power plants, associated gas can be used to cover the field's own needs for electricity. However, any failures in the operation of the gas turbine power plant may result in associated gas flaring (11). Besides, electricity consumption is limited by the needs of the field. If there are no consumers other than the subsoil user company itself, there may be a situation of energy oversupply (12). The payback of this technology is most often achieved by selling electricity to a third-party consumer (13).

4. Increasing oil recovery: application of waterflooding technology often becomes impossible within oil and gas condensate fields due to possible entrapment of gas by water; therefore, it becomes relevant to apply gas methods, more specifically, to enhance oil recovery by injecting carbon dioxide or its mixtures with other gases (for example, as part of associated gas). Water-gas stimulation technologies are also becoming more and more widespread. Nevertheless, it should be noted that in the process of enhancing oil recovery, carbon dioxide accumulation occurs, which requires the introduction of a monitoring and accounting system (14).

5. Increasing gas recovery: hydrodynamic modeling of injection of a mixture of carbon dioxide and hydrogen sulfide, as one of the most harmful associated gas components, in the work (15) showed the realizability of increasing gas production. Gas, due to its high viscosity, density, and solubility, re-pressurizes the formation when injected into the lower part of the formation to displace gas. At the same time, the mixing process is minimized.

6. Gas-to-liquid conversion: converting associated gas into liquid is a complicated and expensive technology, highly susceptible to changes not only in oil prices but also in gas prices. The implementation of this technology is cost-effective not under all market conditions (16). GTL technology makes it possible to convert natural gas into various products such as motor fuel, liquefied gas, lubricating oils, and other chemical products. It is potentially possible to implement GTL technology in the Russian Federation, since the country has significant natural gas reserves. However, specific projects have not been implemented yet. The main reasons for the delay are the high cost and complexity of the technology. Nevertheless, in light of the growing interest in environmentally friendly and energy-efficient fuel production, future development of GTL projects in Russia is possible.

7. Storage: in case of large associated gas volumes and the absence of field connection to the Unified Gas Supply System, the method of temporary underground gas storage is used. This method is based on the theory of creating underground gas storage facilities. Geological objects can be hydrocarbon deposits or aquifers (17). Using this technology within a field has a number of essential advantages: the availability of development history, the state of geological and geophysical exploration, and the confirmed containment capacity of already developed reservoirs.

The choice of one or another technology is based on the reserves of the field, its remoteness from the gas transportation system, the composition of the formation fluid, the stage of field development, already applied associated gas utilization technologies, and many other factors (18).

Currently, a rather new and promising direction is the temporary underground storage of associated gas. As in the case of creating underground gas storages, the objects for future injection can be oil and gas deposits and aquifers. To date, temporary underground gas storage facilities in the gas cap of the developed deposit have been created at the Yurubcheno-Tokhomskoye (19) and Novoportovskoye (18) fields. They also were created in the gas reservoir of the neighboring Vostochno-Messoyakhskoye field, which has not yet been put into development (19), and in the undeveloped gas horizon at the Verkhnechonskoye oil and gas condensate field. Figure 2 shows the classification of temporary underground gas storage facilities created on the basis of the classification of underground gas storage facilities.

The oil and gas industry of Eastern Siberia has been developing rapidly over the last decade. Owing to the remoteness of the main production centers from the existing infrastructure of the region, a significant increase in the volume of gas flared has become noticeable. The existing gas transportation capacities do not yet cover all fields under development or planned for development.

On the example of oil and gas fields in Eastern Siberia we can realize a preliminary algorithm of object selection, which will allow us to distinguish groups of fields, where it is possible to implement the technology of temporary underground gas storage (Figure 3). The fields that already have a connection to the Power of Siberia gas trunkline (Chayanda field) and that will receive it in the near future (Kovykta field) are not included in this algorithm.

The creation of temporary underground gas storage facilities at Eastern Siberian fields will not only help avoid penalties, but also make it possible to generate future profits from gas sales through the Power of Siberia gas pipeline. The experience of realization of such type of facilities at Verkhnechonskoye, Yurubcheno-Tokhomskoye and other fields will help to find the most suitable solutions for such fields as Alinskoye, Tas-Yuryakhskoye and Srednebotuobinskoye.

In this paper aimed to solve the problem of utilization of huge volumes of associated gas from developed oil and gas condensate fields in Eastern Siberia. The technology of temporary underground storage of gas in the aquifer will be considered. Although the topic of this research is relevant to Eastern Siberia, the analysis and conclusions may find application in future research on natural gas storage in aquifers.

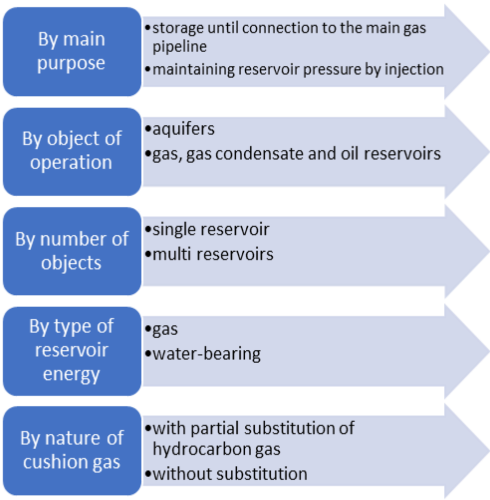

Figure 2. Classification of temporary underground gas storage facilities

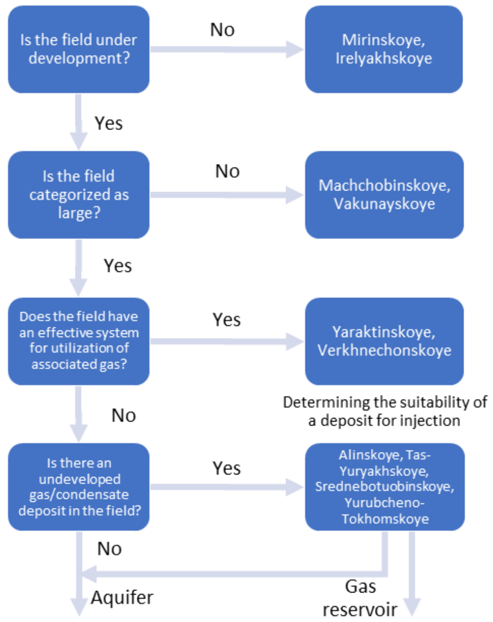

Figure 3. Algorithm for selecting a facility for temporary underground gas storage

2. MATHERIALS AND METHOD

Unlike underground gas storage facilities created in depleted oil and gas reservoirs, aquifers do not have a sufficient amount of wells, and there is not enough data to evaluate the reservoir and fluid seal characteristics. The key indicators for evaluating the pressure integrity of the future storage include permeability, breakthrough pressure, mineral and mechanical brittleness, and the thickness and area of caverns (20).

One of the largest capital expenditure items when creating an underground gas storage facility is the cost of cushion gas, which accounts for about 25–30% of the overall storage facility cost (21). It is also worth noting that cushion gas can account for 15–75% of the total gas volume of the storage facility. Therefore, minimizing its volume makes it possible to significantly reduce capital expenditures.

To replace part of the cushion gas in underground storage facilities, it is possible to use inert gases such as nitrogen and helium or carbon dioxide, as well as various mixtures of these gases. However, then a new problem arises: high miscibility of non-hydrocarbon gases with hydrocarbon gases, resulting in a significant deterioration of the quality and calorific value of the gas extracted from the storage facility. It is also necessary to work out the possibility of using part of hydrocarbon components for the own needs of the field: boiler houses at the facilities, heating of well products, operation of compressor drives, and many other things making up the energy complex and technological needs. In particular, when injecting CO_2, one should take into account the corrosion hazard for equipment due to such factors as the high salinity of formation water and pressure.

Figure 4 presents a typical scheme for an underground gas storage facility in an aquifer combined with partial replacement of cushion gas. The effectiveness of this storage scheme is ensured by various factors. The aquifer should possess both the ability to accumulate gas, i.e. sufficient permeability and porosity, and a reliable fluid seal to prevent gas migration and crossflows. Other mechanisms that determine the efficiency of underground gas storage include rock heterogeneity, relative permeability hysteresis, gas dissolution, and gas miscibility (22).

Two main research methods were chosen for the study:

- Analysis of actual publications on the topic "Methods of associated gas utilization";
- hydrodynamic modeling of aquifer and temporary underground gas storage with partial replacement of cushion gas.

A detailed analysis of existing scientific research in the chosen direction was carried out using the allocation of key topics, taking into account the specific features of the found problem. To achieve the most accurate result, hydrodynamic modeling was carried out in a specialized program using modern computational algorithms that increase the accuracy and speed of calculations.

The results of the study were analyzed using the method of comparing gas and methane withdrawal-to-injection ratios.

2. 1. Associated Gas

In hard-to-reach fields, there is no possibility to deliver gas from the outside; therefore, when choosing cushion gas, it is necessary to take into account the composition of associated gas produced at the field, since the source will be flue gases obtained by combustion. Table 1 presents associated gas composition used in this research.

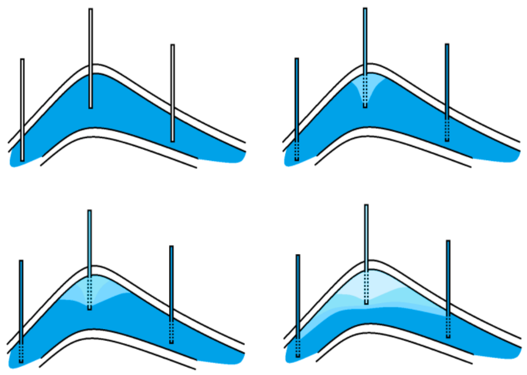

Figure 4. Schematic representation of underground gas storage with partial replacement of cushion volume

TABLE 1. Associated gas composition

N_2	CO_2	H_2S	CH_4	C_2H_6	C_3H_8	iC_4H_{10}	nC_4H_{10}	C_{5+}
0,002	0,035	0,003	0,693	0,132	0,065	0,010	0,028	0,032
0,008	0,025	0,000	0,700	0,124	0,076	0,014	0,035	0,018
0,006	0,025	0,002	0,709	0,163	0,054	0,008	0,016	0,016

2. 2. Aquifer The thermobaric conditions of the selected geological object and the component composition determine such characteristics of the injected gas as the supercompressibility coefficient, density, and viscosity. They also exert a significant impact on the completeness of displacement, the degree of gas mixing, and the volume of cushion gas (23). Calculation was performed for reservoir temperature 298,15 K.

For Eastern Siberia, and in particular, for the Yurubcheno-Tokhomskaya oil and gas accumulation area, three water-bearing complexes are typical: suprasalt, saline, and subsalt. Since for gas storage, a good fluid seal is required, this paper will consider the Osinsky horizon, which is located at the junction of the saline and subsalt formations and overlain by a regional cover – the Usolye suite. Waters of this complex are of the calcium chloride type (24). Table 2 presents the component composition of waters (in mg-eq/dm^3) with a mineralization of 299 g/dm^3 (depths 2090–2100).

Temperatures in the Osinsky horizon vary within 20–30 °C; the pressure is within 21–23 MPa (25). When gas is injected into the horizon, a significant increase in pressure occurs, resulting in changes in the properties of both gas and formation water. To calculate the supercompressibility coefficient, density, and viscosity, it is necessary to assume that the formation temperature is constant.

2. 3. Cushion Gas Properties In this work, the pseudocritical properties of the gas mixture are calculated by the Sutton method for associated gas (26). To correct the dependencies on the content of carbon dioxide and hydrogen sulfide in associated gas, corrections for pseudocritical pressure and temperature obtained by Sutton (26) can be used. In the considered case, the presence of nitrogen should also be taken into account (27). As early as 1942, Standing and Katz (28) developed a diagram of the dependence of the z-factor on pseudo-reduced pressures and temperatures. After that, various researchers proposed mathematical correlation dependencies most closely reproducing the original diagram (27). Standing and Katz (28) evaluated the convergence of most of the above-presented models. The best results were shown by the Hall and Yarborough model. The best results were demonstrated by Hemmati-Sarapardeh et al. (29). Taking this into consideration, the results of the calculation of the supercompressibility coefficient based on these dependences for associated gas and temperature and pressure of the Osinsky horizon are presented in Figure 5.

TABLE 2. Component composition of the Osinsk aquifer

Cl^-	Br^-	SO_4^{2-}	HCO_3^-	Ca^{2+}	Na^+	Mg^{2+}	Fe^{2+}
99,1	0,6	0,2	0,1	45,3	40,6	13,8	0,3

Density and viscosity are found according to Lee's dependencies. The dependency graphs are shown in Figures 6 and 7.

In aquifer conditions, CO_2 has the lowest supercompressibility coefficient, which implies that the volume it will occupy in the formation will be significantly less than that of natural gas, let alone nitrogen. Besides, since the density of CO_2 is significantly higher than that of hydrocarbon gas and nitrogen, carbon dioxide, when injected into the formation, under the influence of the gravity gradient will accumulate in the lower part of the formation. This will

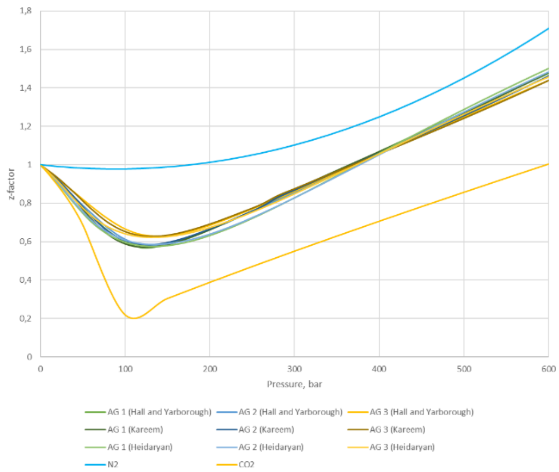

Figure 5. Z-factor dependence on pressure

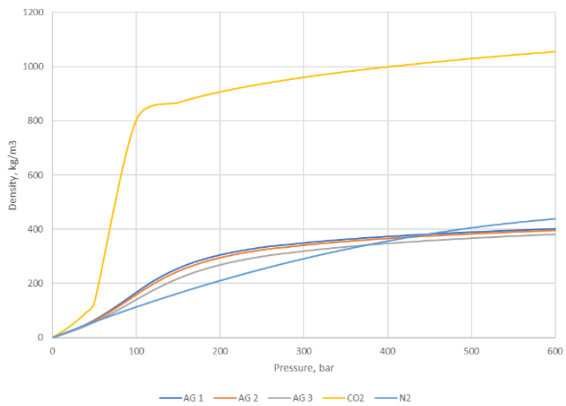

Figure 6. Dependence of density to pressure

make it possible to reduce the degree of mixing of hydrocarbon and non-hydrocarbon gases. When injecting CO_2, it is expedient to perforate the bottom of the production string closer to the formation bottom.

The higher the viscosity of the injected fluid, the better its displacement properties due to the higher ratio of gas viscosity to formation water viscosity.

One can conclude that carbon dioxide has the best displacement ability among gases proposed for use as cushion gases. Nitrogen, in turn, has the worst displacement ability, but due to its significant expansion in the formation, it can provide an effective cushion between CO_2 and associated gas.

Kareem et al. (30) considered the possibility of sequential injection of N_2 and CO_2. The results of the sequential injection experiment showed that this technology made it possible not only to increase the CO_2 storage capacity but also to improve CH_4 recovery. Nuhu et al. (31) studied the displacement of stored CH_4 using a CO_2-N_2 mixture. The results showed that this technology reduced pore swelling and provided high hydrocarbon gas recovery and CO_2 storage. Nitrogen acts as a kind of cushion preventing the mixing of carbon dioxide and methane. It can be concluded that the combined use of nitrogen and carbon dioxide provides better results in terms of both reducing miscibility and displacement of hydrocarbon gas. Zhang et al. (32) investigated adsorption at the gas-rock interface. The highest convergence was achieved using the Cuckoo algorithm.

2. 4. Case Study The present work studies the possibility of minimizing cushion gas by partially replacing it with CO_2, N_2, or their mixture. Using the aquifer model (parameters are presented in Table 3) built in the RFD tNavigator software, an experimental study of 24 storage scenarios was conducted (Figure 8).

Although the presence of water and low temperature catalyze hydrate formation, they were not considered in this model (33, 34). Any deposits in both the borehole and bottomhole area of production and injection wells reduce the productivity and throughput of the well (35, 36). This aspect will also be considered in future studies.

TABLE 3. Aquifer model

Property	Value
Depth, m	2000
Temperature, K	298,15 308,15
Formation pressure, bar	220
Salinity, g/l	290
Porosity, %	20
Permeability, mD	300
Capacity, m	100

The base option was associated gas injection without partial replacement.

The calculation time was taken based on the assumption that in 10 years, the field will be connected to the main gas pipeline, and reverse gas production will start. The model took into account the solubility of injected gas components in the reservoir water.

The relative phase permeabilities in the gas-water system were adjusted based on laboratory studies by Zhu et al. (37). The results are shown in Figure 9.

In models 1–8, both production and injection wells are perforated in the lower part of the formation, and in models 9–16, the upper part of the production well is perforated. The aggregate state of carbon dioxide changed depending on the formation temperature. When the temperature reaches 31.2 °C, it passes to a supercritical state at formation pressure.

The model did not take into account the hysteresis of relative permeabilities. With successive changes in filtration directions, the relative permeability to water is reduced with each cycle (37). The cyclic process results not only in the expansion of the filtration area and enhanced rock hydrophilicity but also in enhanced gas saturation (38).

3. RESULT AND DISCUSSION

Figure 10 shows a dot plot of the dependence of the injected gas volume on the CH_4 extraction-to-injection

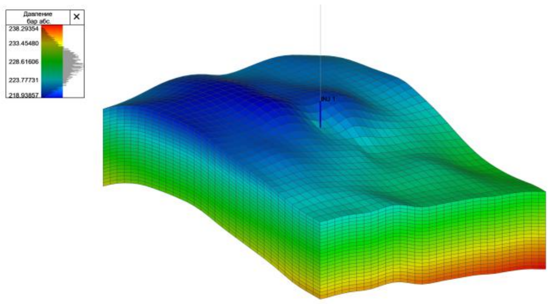

Figure 8. Aquifer model

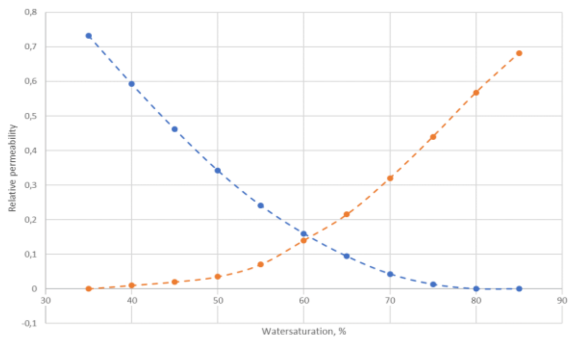

Figure 9. Gas-water relative phase permeabilities

ratio. It can be seen from the figure that the models located 1-6, included in Zone I include a production well and an injection well with perforations from 2050 to 2100 meters, and in Zone II (models 7 -16) a production well with perforations from 2000 to 2050 meters and an injection well with perforations from 2050 to 2100 meters. This implies that it is more efficient to inject cushion gas into the lower part of the aquifer and extract active gas from the upper part. Taking into account that the temporary underground gas storage facility should be able to contain as much associated gas as possible for utilization, the optimal solution is Model 12, where the cushion gas is carbon dioxide in a supercritical state.
Table 4 presents the calculation results for the simulation of partial cushion gas substitution scenarios. When evaluating the results obtained by the ratio of the injected hydrocarbon gas volume to the pumped-out volume, the best results were shown by scenario 16, in which carbon dioxide in a supercritical state is injected first, followed after some time by the injection of nitrogen and then storage gas.

The efficiency of gas extraction from the storage facility is achieved if the injection well is perforated at the bottom and the production well at the top. When calculating options with alternate injection of carbon dioxide and nitrogen, it was considered that the gases were injected for half a year before the injection of hydrocarbon gas started. To further investigate the technology of temporary underground gas storage with

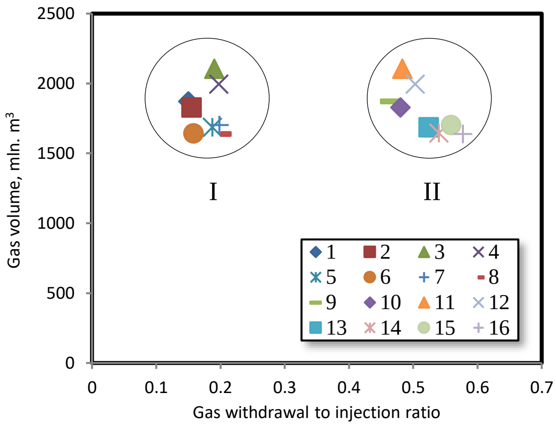

Figure 10. Graph of injected gas volume versus CH_4 withdrawal/injection ratio

partial replacement of cushion gas, it is recommended to study the ratio of carbon dioxide and nitrogen.

Modeling confirmed the effectiveness of injecting dioxide into the lower part of the reservoir: due to its higher density, it is located in the formation below nitrogen and hydrocarbon gases, which reduces its final content in the well products. Water produced together with gas from a production well can be reinjected into the lower part of the formation to increase pressure and increase gas displacement by water when pumping gas out from storage.

TABLE 4. Modeling results

Scenario	Temperature		Gas composition			Production		Gas withdrawal to injection ratio/CH4	
	25°C	35°C	CH_4, mln. m^3	CO_2, mln. m^3	N_2, mln. m^3	Gas, mln. m^3	Water, ths. m^3		
1	+	—	1872	—	—	281	2986	0,150	0,150
2	—	+	1828	—	—	283	3013	0,155	0,155
3	+	—	2105	307	—	401	2928	0,166	0,190
4	—	+	1996	322	—	393	2946	0,169	0,197
5	+	—	1687	—	150	337	3010	0,183	0,187
6	—	+	1644	—	144	288	3023	0,161	0,158
7	+	—	1702	133	216	337	2986	0,164	0,198
8	—	+	1638	136	202	330	3003	0,167	0,201
9	+	—	1872	—	—	870	1789	0,464	0,464
10	—	+	1828	—	—	877	1767	0,480	0,480
11	+	—	2105	307	—	1016	1717	0,421	0,483
12	—	+	1996	322	—	1005	1700	0,433	0,503
13	+	—	1687	—	150	885	1783	0,482	0,524
14	—	+	1645	—	144	890	1759	0,497	0,540
15	+	—	1702	134	216	953	1748	0,464	0,559
16	—	+	1638	136	202	945	1728	0,478	0,577

4. CONCLUSION

This study considered the issue of associated gas flaring at remote hard-to-reach oil and gas condensate fields, which are planned to be connected to the main gas pipelines only in the long run. For this type of facilities, most often the applied methods of associated gas utilization turn out to be unsuitable, which leads to the search for technologies of gas reserves conservation. Underground gas storage is an effective method of solving this problem, but it is also capital intensive. In this regard, it becomes urgent to search for and create a technology that allows to reduce the cost of creating a storage facility and increase its efficiency. This research consists in studying the possibility of partial substitution of hydrocarbon cushion gas by carbon dioxide and/or nitrogen. Using hydrodynamic modeling of the aquifer corresponding to the geological conditions of Eastern Siberia, sixteen scenarios of storage creation with different composition of cushion gas were investigated. As a result of analysis and comparison, the most effective gas mixture composition and injection and withdrawal method were determined.

As one of the most effective methods for solving this problem, the technology of temporary underground gas storage with partial replacement of cushion gas with carbon dioxide, nitrogen, or their combination was chosen. Based on the analysis of the dependencies of the supercompressibility coefficient, density, and viscosity on pressure at a constant temperature and modeling of the aquifer, the following conclusions can be drawn:

1. Due to the lowest z-factor coefficient, the volume occupied in the formation by carbon dioxide is much smaller than that of natural gas, let alone nitrogen.
2. Among the gases considered, carbon dioxide has the highest density in reservoir conditions ($\rho_{CO_2} = 906\frac{kg}{m^3}$), which indicates that it will occupy lower formations in the reservoir in relation to the active gas.
3. The greatest change in the properties of the gas occurs in case of its transition to a supercritical state. The higher viscosity of the gas ensures more efficient water displacement.
4. The scenario of alternate injection of carbon dioxide and nitrogen is the most favorable in terms of the ratio of gas extraction to gas injection (0,577 $\frac{m^3}{m^3}$).
5. The scenario implying the injection of supercritical carbon dioxide as a cushion gas at the top perforation of the production well was selected as the most optimal one.
6. The group of scenarios with top perforation of the production well showed better results than those with bottom perforation. This is due to the low density of natural gas that tends to rise upwards.
7. The main limitation of the selected technology is the supercritical state of carbon dioxide, to which it passes when it reaches a temperature of 31.2 ºC. It is desirable to select aquifers with temperatures above the critical temperature.

The academic contribution of this work is the creation of a new aquifer model that takes into account the solubility of the gases injected into it, as well as the allocation of the most effective gas injection technology by comparing and contrasting sixteen major existing scenarios.

Practical application of the research results is possible both in remote and hard-to-reach oil and gas condensate fields and in the creation of underground storage facilities in aquifers.

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Persian Abstract

چکیده

شعله ور شدن گاز همراه همچنان یک مشکل برای میادین نفت و گازی است که دسترسی به آنها دشوار است و از زیرساخت ها دور هستند. توسعه فعال تولید نفت و گاز در سیبری شرقی به این واقعیت منجر شده است که ظرفیت های حمل و نقل نمی تواند با توسعه میدان همگام شود. افزایش شعله ور شدن گازهای همراه منجر به افزایش قابل توجه گازهای گلخانه ای مانند دی اکسید کربن و متان می شود. راه حل احتمالی این مشکل، ذخیره گاز در سفره آب این میدان برای فروش آتی و کسب درآمد از طریق خط لوله اصلی گاز است. این مقاله فن‌آوری‌های اصلی استفاده از گاز مرتبط را تحلیل می‌کند و مشکل دور بودن از زیرساخت‌های حمل و نقل گاز میادین صعب العبور را نشان می‌دهد. یک فناوری موثر برای حل این مشکل، ایجاد ذخیره‌سازی موقت زیرزمینی گاز همراه در آبخوان میدان است. نتایج مدلسازی هیدرودینامیکی تحقق این فناوری با جایگزینی جزئی گاز بالشتک نشان داد که تزریق مشترک دی اکسید کربن و نیتروژن قبل از گاز هیدروکربن امکان افزایش نسبت بین گاز تولیدی و تزریقی را فراهم می کند که نشان دهنده کارایی بیشتر آن است. توصیه می‌شود برای پیاده‌سازی این فناوری، هنگام انتخاب محل تزریق زمین‌شناسی، روی سفره‌های زیرزمینی با دمای بالاتر از ۳۱.۲ درجه سانتی‌گراد تمرکز شود که باعث می‌شود دی اکسید کربن در شرایط مخزن در حالت فوق بحرانی باقی بماند.