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THE ANALYSIS OF CO_2 INJECTION IN DEPLETED GAS RESERVOIRS DURING THE SEQUESTRATION PROCESS**

1. INTRODUCTION

The technology is constantly being developed, therefore the demand for energy is intensively increasing. The main source of energy are fossil fuels, which currently provide for 85% of the world's energy requirements. Although the increasing number of used fuels are environmentally friendly, the atmosphere is still being polluted by the excess greenhouse gases, which consist mainly of: carbon dioxide, methane and ozone. However, CO_2 makes the biggest contribution to the environmental pollution – its current concentration in the atmosphere has been highest in the history. Experts dealing with climate changes estimate that without new technologies in the area of reducing carbon dioxide emission, its concentration will be systematically increasing [3].

The most perspective methods of limiting the CO_2 emission are: decreasing energy consumption through efficiency improvement, enhancing the use of the renewable energy sources (wind, sun, geothermal energy) and CCS (Carbon Capture and Storage) technology to provide the long-term CO_2 storage in the Earth's lithosphere, biosphere and hydrosphere and thus reduce or slow down its emission to the atmosphere [5].

The first stage of CCS technology is the capture of CO_2 from flue gases and then, compression to the liquid or supercritical state. It is essential for technological and economic effectiveness of transport. The next step is to transport captured carbon dioxide to a place of storage. It could be achieved by using pipelines, road/rail tanks or ships. The last element of the sequestration technological chain, after capturing and transporting, is CO_2 storing.

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The most suitable geological structures are: aquifers, deep coal seams and depleted hydrocarbon reservoirs, of which depleted gas reservoirs have high sequestrating potential mainly by virtue of proven record of geological recognition and high recovery factor, hence, considerable storage capacity. Furthermore, CO_2 storage in hydrocarbon reservoirs could be coupled with the increase of gas (EGR) or oil (EOR) recovery factor [7]. The efficiency of these methods is higher in the case of oil reservoirs due to relatively low recovery factors and higher effectiveness of miscible flooding. The financial profits from oil (or gas) extracted in this way could partly compensate for the cost of capture and transport of carbon dioxide. From the other point of view the high values of storage capacities as well as recovery factors plead in favor of using gas reservoirs for sequestration purposes.

A depleted gas reservoir could store substantially more gas than a depleted oil reservoir while both have the same pore volume. This fact results mainly from two reasons [2]:

- Average recovery factor is about 65% in the case of depleted gas reservoirs versus 35% when it comes to oil reservoirs. This indicates that the more hydrocarbons are extracted, the bigger is the storage capacity for carbon dioxide.
- Gas is approximately 30 times more compressible than oil or water. At 13.8 MPa, an isothermal compressibility of natural gas is typically about $72.5 \cdot 10^{-6}\,kPa^{-1}$ and $2.2 \cdot 10^{-6}\,kPa^{-1}$ for oil. This means that in the reservoir conditions gas will significantly change its volume with the variation of pressure, which results in the increase of storage capacity.

The process of CO_2 storage in depleted reservoir is connected with considerable changes in pressure and temperature of injected gas during its flow both in the well tubing and in reservoir pore space. Thus, the variation of thermodynamic parameters is the key for the proper description of the injection process. The regime of fluid flow as well as the required wellhead injection pressure depends on numerous aspects, i.e. the injection rate, the number of used injection wells, changes in temperature and reservoir pressure. The pressure drop inside the well is in general a function of two factors: firstly, fluid density and associated pressure of gas column, and secondly, pressure loss connected with flow resistance inside the injection well. Considering the big changes of CO_2 properties, especially in the near-critical area, the contribution of mentioned factors could vary across the wide range with the depth of the well. However, it is vital to remember that during the fluid flow from the head to the bottom of the well, the pressure exerted by the column of gas will facilitate the injection process by decreasing the required wellhead injection pressure.

2. THE CHARACTERISTICS OF CO_2 AND $CO_2 - CH_4$ MIXTURES

Considering specific features of carbon dioxide, modelling its injection demands proper characteristics of PVT properties across the range of pressures which are expected to occur during the storage process.

CO_2 is colorless, odorless and a little heavier than air gas in atmospheric conditions. The critical point is 73.8 bars at 31.0°C (Fig. 1). The grey p T path shown in Figure 1 stands for a range of pressure and temperature conditions expected during CO_2 storing in depleted geological structures. Above the critical parameters gas is in the supercritical state and behaves partly like fluid and partly like gas. This situation will happen in reservoirs deposited below 800 meters with reservoir temperature min. 31°C. However, when it comes to depleted reservoirs, the bottomhole pressure could be lower than the hydrostatic pressure (CO_2 would be in subcritical conditions). For that reason it is essential to take under consideration both sub- and supercritical state during the simulation and when estimating storage capacity in this kind of deposits.

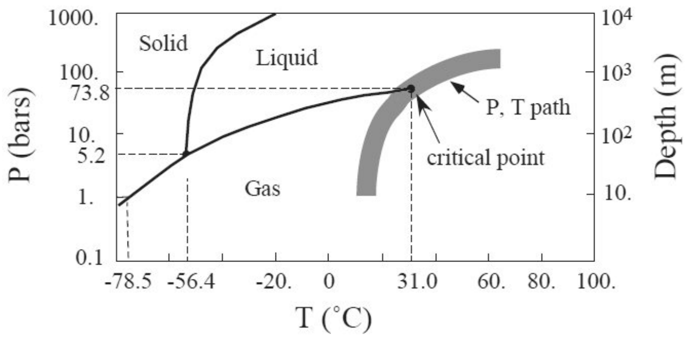

Fig. 1. CO_2 phase diagram [4]

Basic elements affecting the CO_2 injection process are viscosity and density of carbon dioxide. Estimation of these parameters for pure CO_2 in various pressures and temperatures was obtained with the use of PVTi module of the Schlumberger Eclipse Reservoir Simulator (Fig. 2 and 3). As presented, values of both viscosity and density increase with the rise of pressure and are lower in higher temperatures. The most characteristic area is near-critical region, where a substantial change of analyzed parameters could be seen. At pressures below the critical point, CO_2 would be gas-like, i.e. would have relatively low viscosities and densities. In contrast, above the critical point a significant growth of these parameters could be observed. So rapid changes of viscosity and density values result from CO_2 transition into a supercritical state.

According to CO_2 storage in depleted gas reservoirs, a miscible displacement of injected gas and *in-situ* gas takes place. Injected carbon dioxide has the highest concentration close to the injection well. Then, with the rise of distance from the well, the value of concentration gradually drops. As a consequence three specific areas could be identified in the reservoir: CO_2-high-concentration area, miscible displacement area and region saturated only with in-situ gas. Thus, it is crucial to describe PVT properties values of not only pure components (i.e. CO_2 and CH_4) but also of their mixtures. Density and viscosity of methane and carbon dioxide mixtures in 60°C at different pressures are presented in Figures 4 and 5. The X axis represents the percentage of CO_2 in $CO_2 - CH_4$ mixture.

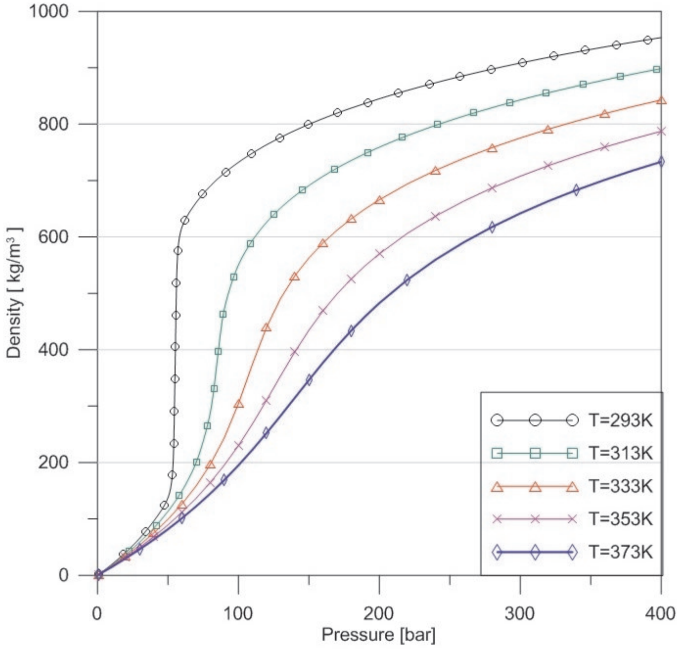

Fig. 2. Density of pure CO_2 at various conditions of pressure and temperature

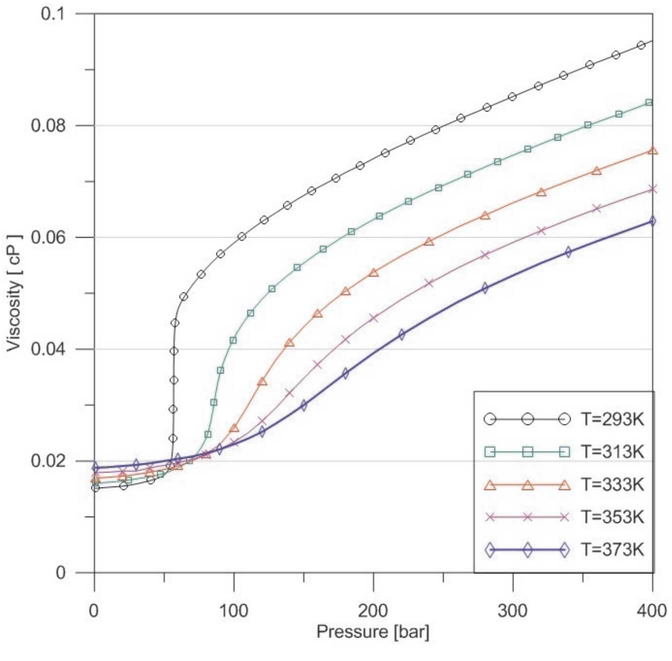

Fig. 3. Viscosity of pure CO_2 at various conditions of pressure and temperature

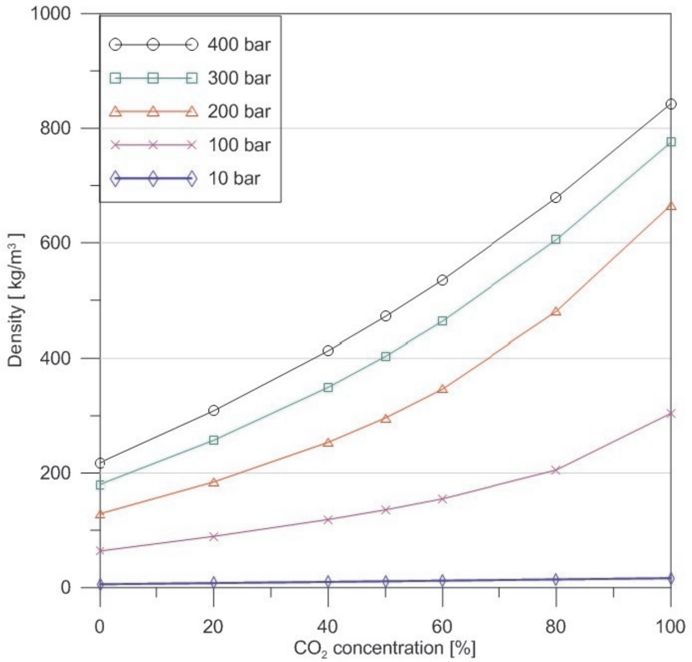

Fig. 4. Density of CO_2 – CH_4 mixtures in 60°C

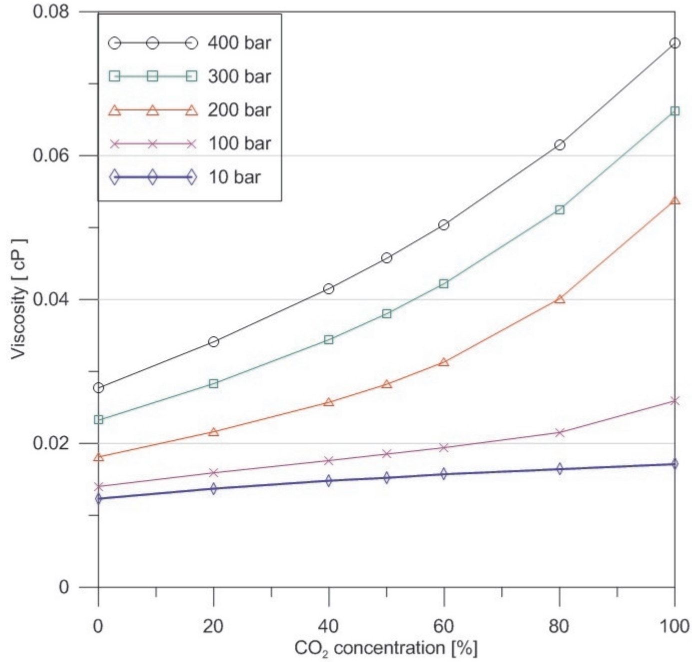

Fig. 5. Viscosity of CO_2 – CH_4 mixtures in 60°C

One of the most important conclusions which can be drawn while analyzing the properties of $CO_2 - CH_4$ mixtures is that the density gradually grows with the increase of CO_2 concentration. In the case of pure methane (x = 0%) the values of density rise with the pressure, exceeding 200 kg/m^3 at 400 bars. On the other hand, the density of pure CO_2 (x = 100%) more extensively increases, exceeding 800 kg/m^3 at 400 bars.

As with density, the viscosity values of pure CO_2 (x = 100%) largely grow with the increase of pressure, exceeding 0.07 cP at 400 bars. By contrast, values of pure methane viscosity change in a narrower range at the investigated pressures, i.e. 0.01–0.03 cP. Interpreting the changes in viscosity of $CO_2 - CH_4$ mixtures, a gradual increase of viscosity with the growth of CO_2 percentage in the mixture could be seen.

Considering the variability of PVT parameters, an important conclusion could be drawn: at higher pressures CO_2 density value is close to the density of water (liquid-like). On the other hand the viscosity of CO_2 rises 2–3 times in highly concentrated mixtures with methane, but its values still remain relatively low. Accordingly, CO_2 in supercritical state is a fluid with high mobility and significant density at the same time.

3. CARBON DIOXIDE INJECTION ANALYSIS

The analyses concentrated on the feasibility of CO_2 injection into a depleted gas reservoir. All calculations were based on data of the existing gas deposit in southeastern Carpathian Foreland. Reservoir rocks in the most part consist of Miocene sandstones and mudstones. 22 layers deposited at a depth of 550 to 3000 m were discovered in the reservoir structure. However, only the biggest layer having the best permeability properties was taken into account in the analysis. The investigated deposit has been exploited with six wells. Basic parameters of this geological structure are presented in Table 1.

Table 1

Characteristics of analyzed layer

Reservoir depth	1560–1650 m
Type of the seal	Clays
Average thickness	75 m
Average porosity	22.8%
Permeability	56.9–94.7 mD
Initial reservoir pressure	15.24 MPa
Reservoir fluid	Methane-rich natural gas (98.8% CH_4)
Number of production wells	6
Total gas production	$4.927 \cdot 10^9$ Nm^3

The analysis included the possibility of CO_2 storage in a chosen reservoir when the estimation of its storage capacity is coupled with enhancing *in situ* gas recovery. The main goal of the performed analysis was to evaluate CO_2 flow in the injection wells at different conditions depending on reservoir pressure during the injection process. In this analysis we also investigated injection with various flow rates using 2, 4 and 6 injection wells equipped with tubing of 2 3/8" and 3 1/2".

Calculations were made with the assumption of maximum possible recovery factor, i.e. 95%. The analysis focused on three scenarios for two, four and six injection wells. The investigated project assumed preparing the existing production wells to the CO_2 injection process, including both leakage checking and anti-corrosion protection of the pipes. Conducted scenario analysis was based on the following initial assumptions:

- Reservoir temperature – estimated on the basis of geothermal gradient.
- Linear function of temperature inside the well.
- 30-years period of injection process.
- Constant injection rate resulting from the chosen scenario and injection time period.
- Pure carbon dioxide as an injection fluid.

4. RESULTS AND DISCUSSION

Using historical production data, i.e. production rates and reservoir pressure, basing on material balance equation, the original gas in place was estimated to $5.6 \cdot 10^9$ Nm^3, which means that the current recovery factor was 82.4%. The analysis proved that the investigated deposit was a volumetric type of reservoir.

Taking into account initial gas in place as well as conditions of initial pressure and reservoir temperature, the volume available for hydrocarbons was evaluated to $38.8 \cdot 10^6$ Nm^3. The next step of the analysis was to predict the quantity of CO_2, which could be potentially stored in the pore space, for various recovery factors. The results are presented in Table 2. The amount of injected CO_2 changes proportionally to the value of the recovery factor. Therefore, increasing the production rate from current 82.4% to 95% gives additional $1.490 \cdot 10^9$ Nm^3 of CO_2, which could be stored. Reservoir pressure at the start of injection process will be equal to the reservoir pressure at the end of production period and its values were estimated with the use of the material balance equation [6]. The maximum injection pressure was assumed as equal to initial reservoir pressure.

From the point of view of sequestration process, the main goal is to store the biggest possible quantity of CO_2. Thus, further calculations were conducted on the assumption that the recovery factor value was about 95%, which gives the greatest pore volume available for stored carbon dioxide. In this case two possible options should be considered: continuation of hydrocarbon production with a simultaneous CO_2 injection or reservoir exploitation to the level of 95% in the first place and then CO_2 storage. Due to the risk of CO_2 breakthrough to the producing wells, the second scenario, which assumes CO_2 storing after the gas production stops, is more optimum.

Table 2

CO_2 storage capacity related to various recovery factors

Recovery factor	Storage capacity		Pressure	
			Beginning of the injection	End of the injection
[%]	$\times10^9$ [Nm^3]	[Mt]	[MPa]	[MPa]
82.4*	9.747	19.277	2.966	15.238
85	10.054	19.886	2.543	
90	10.646	21.055	1.716	
95	11.237	22.225	0.869	

* current recovery factor

Fluid flow in the reservoir was described with the use of backpressure relation. The parameters of this equation, i.e. a and b were taken from the well test results for one of the existing wells. The values of these parameters are: a = 2.35 $at^2 \cdot min/m^3$ and b = 0.00054 $at^2 \cdot min^2/m^6$. Due to large differences in the properties of the injected CO_2 and reservoir native gas, these parameters were corrected by the following relations:

$$a(p) = a_i \cdot \frac{z_i}{\mu_i} \cdot \frac{\mu(p)}{z(p)} \tag{1}$$

$$b(p) = b_i \cdot \frac{z_i}{\mu_i} \cdot \frac{\mu(p)}{z(p)} \tag{2}$$

The parameters of this equation, i.e. a and b were taken from the well test results for the existing wells. The values of these parameters are: a = 2.35 $at^2 \cdot min/m^3$ and b = 0.00054 $at^2 \cdot min^2/m^6$. Due to large differences in the properties of the injected CO_2 and reservoir native gas, these parameters were corrected by the following relations.

Calculations of the injection process were conducted including three different scenarios for a different number of wells. Therefore, the injection rate of a single well is a function of: the amount of CO_2 assumed to be stored, time of the injection process and number of used wells. Estimated injection rates are presented in Table 3.

Table 3

Injection rate of a single well in the relation with chosen scenario

Number of wells		2	4	6
Injection rate	1000 Nm^3/day	512,761	256,381	170,920
	tons/day	1014,174	507,087	338,058

Basing on the estimated injection rates and in accordance with a backpressure relation, first the wellbore injection pressures were evaluated. Then, values of required wellhead injection pressure were estimated with the use of VFPi module (Schlumberger's Eclipse). Moreover, the analysis included the distribution of pressure, velocity and density of the flowing CO_2 in a function of depth. The calculations were applied for two pipe diameters: 2 3/8" and 3 1/2" on the assumption of linear temperature distribution inside the well between: the wellhead temperature at the level of 309 K and reservoir temperature of 330 K. The value of wellhead temperature results from the conditions that are needed to transport CO_2 in the supercritical state. The analysis was conducted for various stages of injection process, that is various CO_2 stored quantities and the corresponding reservoir pressures.

The calculation results of each scenario with well tubing diameter of 2 3/8" are presented in Figures 6 to 10. Figures 6 to 8 show the distribution of pressure throughout the well at various stages of injection process, i.e. for different reservoir pressures and injection rates (indicated from using two, four or six injection wells). With the increase of the injected CO_2 quantity, the reservoir pressure gradually grows from about 1 MPa (pressure at the abandonment) to the maximum injection pressure which is equal to the initial reservoir pressure (slightly above 15 MPa).

In the first stage of CO_2 storage process, the reservoir pressure would be substantially lower than the carbon dioxide critical pressure. Therefore, both in reservoir and bottomhole conditions the injected CO_2 would be in gaseous phase despite the fact, that at the same time CO_2 could be in a supercritical state at the wellhead. This is a result of significant changes of carbon dioxide properties during the flow, especially in the conditions close to the critical region. The effect could be observed in Figures 6–8. At the beginning of injection process (low reservoir pressure) in the lower parts of the well the fluid flows in gaseous phase. Injected with a constant injection rate, CO_2 considerably lowers its density as an effect of gas expansion. This results in high flow velocities in the range of 30–60 m/s (Fig. 10) and therefore, large flow resistance and pressure drop. A considerable pressure loss in the lower intervals of the well causes an increase of injected CO_2 pressure in the middle parts of the well and thus, its transition into supercritical state. In the supercritical region, the density grows extensively as a result of phase changes (Fig. 9). Afterwards, a fundamental change of flow velocities and flow resistance could be observed (Fig. 10). At the upper parts of the well, the density of CO_2 continues to rise which is the reason for rising pressure of gas column in the well. These phenomena are especially noticeable in the scenario with two injection wells, where the highest injection rates are applied and at the same time the differences between bottomhole and wellhead injection pressures are the greatest.

As the injection of CO_2 continues, the porous space is being filled up and the reservoir pressure exceeds the CO_2 critical pressure. This, in turn, has an impact on the flow regime changes in the tubing. At this stage the injected carbon dioxide along the whole length of the well is in the supercritical state having high density and relatively low viscosity.

Because of the substantial value of CO_2 density, the pressure of the gas column plays a dominating role in the injection process. In this stage pressure loss is relatively low and drops with the decrease of injection rate. Required wellhead pressures are equal or lower than the critical pressure of CO_2 and the fluid pressure inside the tubing is a linear function of depth (Figs. 7 and 8).

At the final stage of the storing process, when the reservoir pressure is close to its initial value, the pressure of fluid column is sufficient to inject CO_2 with a minor increase of wellhead pressure.

The analysis of the investigated scenarios of injection with various flow rates reveals that injecting with high rates necessitates compressing CO_2 to high pressures, which is a result of significant flow resistance. This situation could occur especially at the beginning of the injection process, when reservoir pressure is much lower than CO_2 critical pressure. An increase in the number of the used injection wells results in the drop of the single well injection rate, and at the same time, in a decrease of the required wellhead injection pressure. Relation between required wellhead injection pressure and bottomhole injection pressure at various stages of injection process, being a function of the number of injection wells, is shown in Figure 11 and in Table 4.

From the point of view of fluid transport in the tubing, it is essential to maintain stable conditions of injection process. In the case of carbon dioxide, it means keeping flow conditions which ensure no phase changes along the whole length of the well. Considering a low value of reservoir pressure after the abandonment, CO_2 at reservoir conditions will be in gaseous phase. That fact indicates maintaining flow in the same state. As the carbon dioxide is being injected, reservoir pressure is rising and after exceeding the critical pressure value, the flow conditions should provide a supercritical state. The analysis of the investigated results shows that the 4 well scenario may be the most appropriate option. With the higher injection rates (scenario with two injection wells) at the beginning stage of storage process, CO_2 is in the supercritical state in the upper intervals of the well, and in gaseous phase in the lower parts. This in turn causes large pressure drops, connected with flow resistance due to CO_2 phase changes. When applying low injection rates (scenario with 6 injection wells), the stored carbon dioxide remains in the gas phase in the upper intervals of the well for most time of the injection process. In the lower parts, when reservoir pressure exceeds the critical pressure, CO_2 is a supercritical fluid.

Taking into consideration the economical aspects, the cost of storing process mainly depends on the number of used injection wells and costs of gas compression. With the low injection rates the number of the required injection wells grows and at the same time the power of the compressors drops. In the opposite case, when high injection rates are involved, the number of wells decreases, but the required wellhead injection pressure grows. At this point it is important to notice that the pressure drop inside the well will be much higher when carbon dioxide is in the gaseous phase.

The decrease of the pressure in the tubing could be implemented by the increasing pipe diameter. Applying the same assumptions as before, an alternative calculations were made for two, four and six injection wells equipped with pipes of diameter 3 1/2" instead of 2 3/8". The results are presented in Figure 12 and Table 4.

As shown, with the increase of pipe diameter, the values of the required wellhead injection pressures significantly drop. It is a result from the fact, that pressure loss during the fluid flow is strongly dependent on the diameter of the pipes. It is worth noticing that in the scenario with six wells and lower tubing diameter (2 3/8") the required wellhead injection pressures are quite similar to the results of scenario with bigger diameter (3 1/2") using only two injection wells. What is more, injection with higher number of wells (i.e. with lower injection rate) substantially decreases the required wellhead injection pressures, especially at the beginning stage of storage process. Once the reservoir pressure exceeds the CO_2 critical pressure, fluid transport becomes inefficient because of increasing pressure loss connected with changes of PVT properties in near-critical region. At the end of the storing process in all scenarios (two, four, six wells) the values of required wellhead injection pressures are similar to each other (75–78 bars). This means that surface apparatus requirements will be the same for each case. In these circumstances, the economic sense of using four or six injection wells becomes questionable. However, solving this issue needs precise economic analysis.

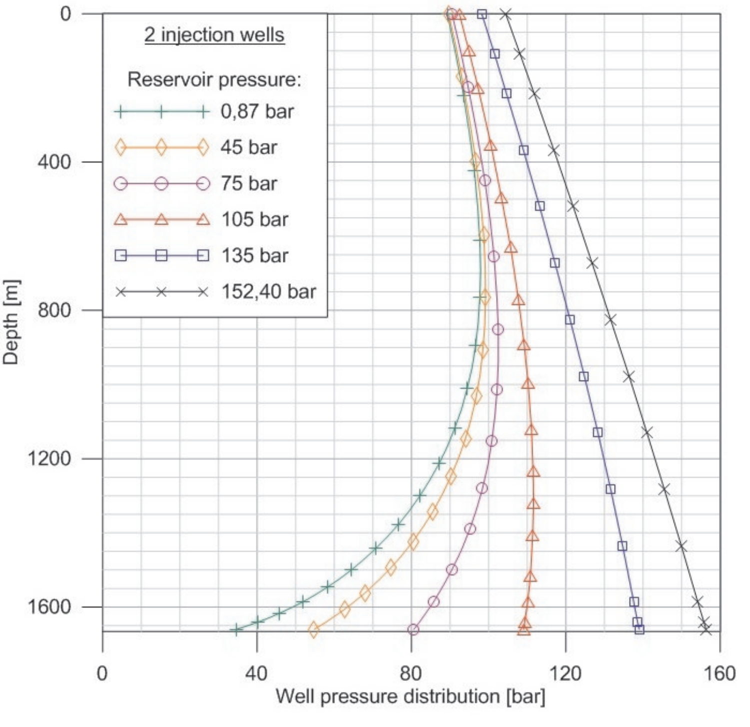

Fig. 6. Well pressure distribution – scenario with two injection wells

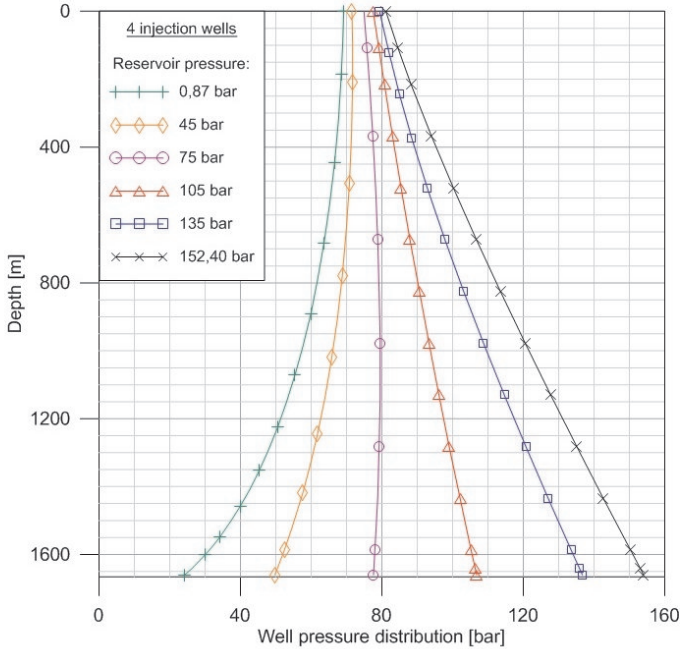

Fig. 7. Well pressure distribution – scenario with four injection wells

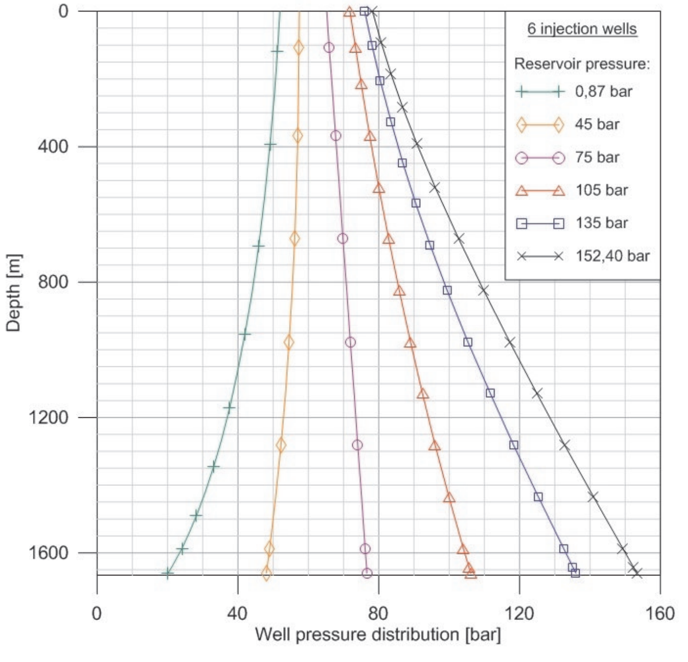

Fig. 8. Well pressure distribution – scenario with six injection wells

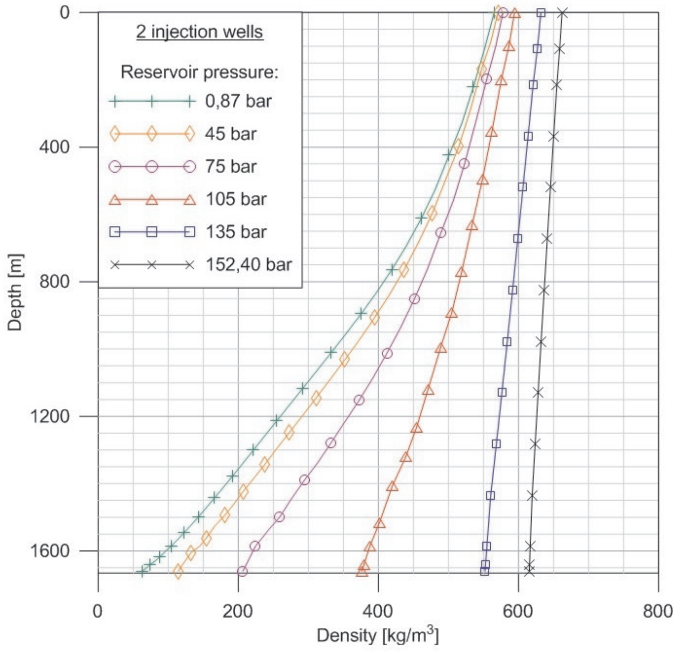

Fig. 9. Distribution of injected CO_2 density

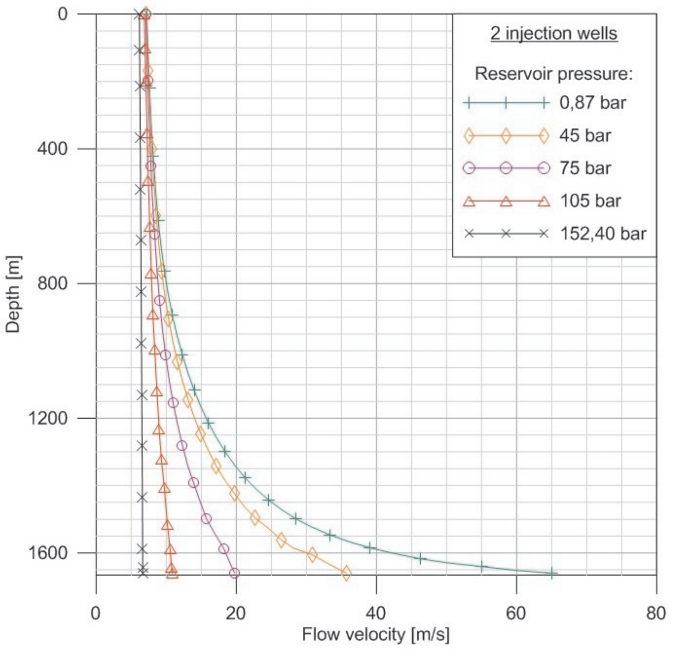

Fig. 10. Distribution of flow velocity

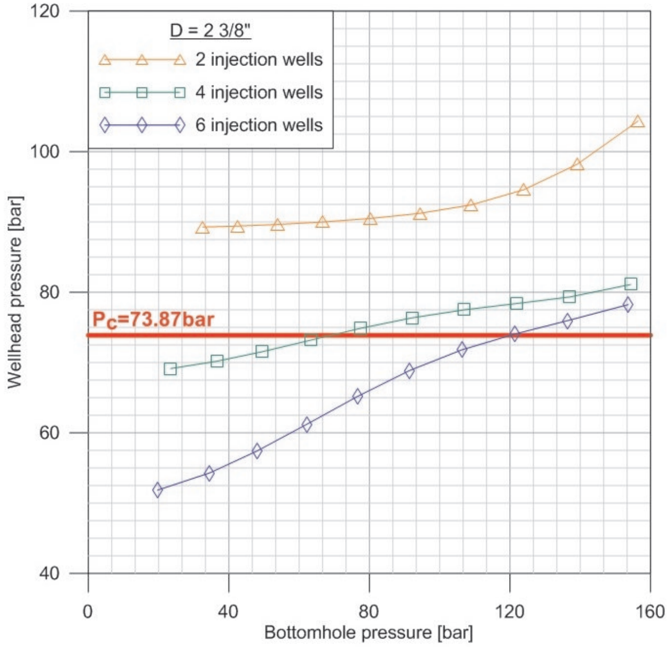

Fig. 11. Required wellhead injection pressure for all scenarios – diameter: 2 3/8"

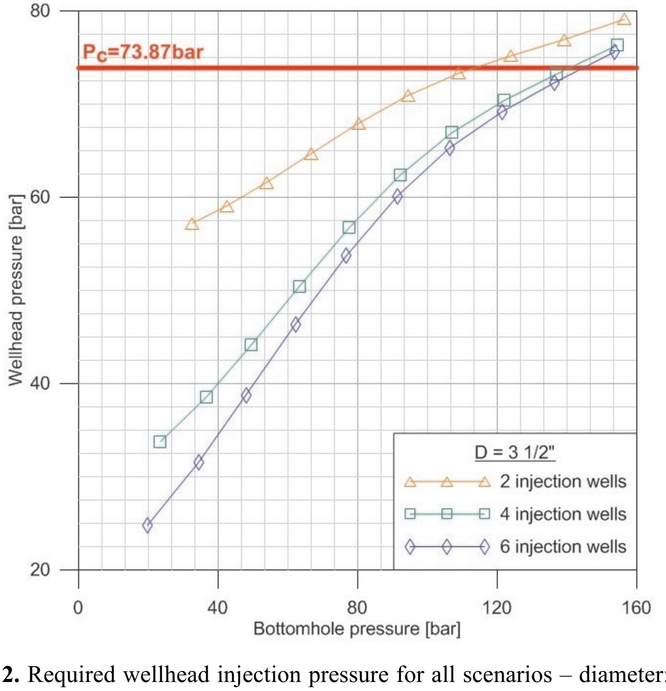

Fig. 12. Required wellhead injection pressure for all scenarios – diameter: 3 1/2"

Table 4

Required wellhead pressure for various tubing diameters

Reservoir pressure [bar]	Wellhead pressure [bar]					
	Tubing diameter 2 3/8"			Tubing diameter 3 1/2"		
	2 wells	4 wells	6 wells	2 wells	4 wells	6 wells
0.87	89.19	69.07	52.16	55.71	33.32	25.70
30.00	89.32	70.11	54.55	57.76	38.19	32.25
45.00	89.54	71.46	57.63	60.44	43.85	39.24
60.00	89.87	73.13	61.39	63.74	50.22	46.73
75.00	90.36	74.84	65.34	67.22	56.57	53.94
90.00	91.08	76.34	68.96	70.41	62.26	60.30
105.00	92.20	77.48	71.88	72.98	66.85	65.40
120.00	94.19	78.38	74.10	74.92	70.32	69.25
135.00	97.53	79.31	76.00	76.63	73.16	72.36
152.40	103.01	81.07	78.30	78.76	76.26	75.69

5. CONCLUSIONS

Depleted gas reservoirs are geological formations with a high sequestrating potential. The main advantages of using them for CO_2 storing are: proven integrity of the reservoir which provides safety of storing, great storage capacities connected with high recovery factors and also ability to use existing wells and surface infrastructure. Moreover, storing in this kind of reservoirs could be coupled with enhancing the recovery factor.

Gaseous CO_2 has specific properties, which can be either positive or negative as far as carbon dioxide storage process is concerned. Depending on the conditions of reservoir pressure and temperature, injected fluid can be in gaseous or supercritical state. The most characteristic is near-critical region, where the thermodynamic properties largely change. At pressures above the critical point, CO_2 is gas-like, i.e. has relatively low viscosity and density. However, as a subcritical fluid, carbon dioxide has a high density but relatively low viscosity.

The process of CO_2 storage in depleted gas reservoirs is connected with significant pressure and temperature changes of injected gas during its flow both in the tubing and in the reservoir pore space. Depending on injection rate, the number of injection wells, their design, changes of temperature with depth and value of actual reservoir pressure, the flow regime changes, too. As a consequence, the required wellhead pressure is correspondingly a function of mentioned parameters.

Conducted analysis proves that CO_2 injection in gas phase is inefficient because of the substantial pressure loss associated with flow resistance in the well tubing. Injection in the supercritical state seems to be much more favorable; considering the high density of CO_2 and simultaneously low viscosity in this phase, the pressure loss during the flow in the tubing is significantly smaller. In addition, high value of CO_2 density makes the pressure of gas column grow, thus supporting the injection process.

A relevant factor influencing the carbon dioxide transport in the well tubing is a diameter of the pipes. On one hand, the proper selection of the diameter would have an effect on the required wellhead injection pressures, and on the number of injection wells. The obtained calculation results show that the conditions of injection process with the use of two 3 1/2" tubing are similar to the scenario with three times lower injection rate and six 2 3/8" tubing. Decreasing the injection rate in wells having bigger diameters allows the wellhead pressure to considerably drop. This issue is especially important in the beginning of the injection process, when the reservoir pressure is lower than CO_2 critical pressure and the injected fluid is in gaseous phase at reservoir conditions.

The analyzed reservoir is an example of a formation which could properly work as an underground CO_2 storage facility. It has a considerably large storage capacity and high recover factor – these aspects determine the use of formation for sequestration purposes. The existing and operating infrastructure (with the on-going production) is an additional advantage which could compensate for the costs of the whole project.

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