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Analysis of the enhanced oil recovery process through a bilateral well using WAG-CO_2 based on reservoir simulation. Part II – real reservoir model

Based on the general conclusions in part I of the study, this part II presents the analysis of the selected EOR methods with particular attention paid to the WAG (Water-Alternating-Gas) method and its SWAG (Simultaneous Water-Alternating-Gas) version, involving the simultaneous and selective injecting of water and CO_2 (water through the upper section of the injection well, CO_2 through the lower section of the well) for a real reservoir model. Forecasts of oil production have been performed with the use of the primary method, waterflooding method as well as the WAG and SWAG methods. For each of the above production methods, additional options were considered to increase the number of injection wells from 6 to 8. In order to perform the above described forecasts, a number of general assumptions were made concerning the amount of injected and produced liquids as well as limitations associated with them. The paper presents a detailed analysis of the reservoir operation for each case. Results of total amounts of the injected and produced fluids are presented in detail. Qualitative assessment of the analyzed methods is presented based on the main simulation results including distribution of oil saturation in the reservoir model at the end of production forecasts.

Key words: EOR, WAG, SWAG, CO_2 injection, miscible displacement, bilateral wells.

Analiza procesu wspomaganego wydobycia ropy odwiertem bilateralnym z wykorzystaniem WAG-CO_2 w oparciu o symulacje złożowe. Część II – model złoża rzeczywistego

Bazując na wnioskach ogólnych w części I pracy w niniejszej II części przedstawiono analizę wybranych metod EOR ze szczególnym uwzględnieniem metody WAG (*Water-Alternating-Gas*) i jej odmiany SWAG (*Simultaneous Water-Alternating-Gas*) polegającej na równoczesnym i selektywnym tłoczeniu wody i CO_2 (górną sekcją wody, dolną sekcją CO_2) dla modelu rzeczywistego złoża. Przeprowadzono prognozy wydobycia ropy przy użyciu metody pierwszej, metody nawadniania i metod WAG i SWAG. Dla każdej z powyższych metod wspomagania wydobycia rozpatrzono dodatkowe warianty zakładające zwiększenie liczby odwiertów tłoczących z 6 do 8. W celu przeprowadzenia powyżej opisanych prognoz przyjęto szereg założeń ogólnych dotyczących ilości zatłaczanych i wydobywanych płynów oraz ograniczeń z tym związanych. W pracy przedstawiono szczegółową analizę pracy złoża dla każdego wariantu. Podano szczegółowe wyniki dla sumarycznych wielkości zatłaczanych i wydobytych płynów. Ocenę jakościową przedstawiono w oparciu o podstawowe wyniki eksploatacji, w tym rozkłady nasycenia ropą w złożu na koniec jej eksploatacji złoża.

Słowa kluczowe: wspomagane wydobycie ropy, naprzemienne zatłaczanie wody i gazu, zatłaczanie CO_2, wypieranie typu mieszającego, odwierty wielodenne.

Introduction

Production of oil from oil reservoirs that have recently been exploited in Poland is performed mainly with the use of the primary method and, in some cases, also with the use of the secondary method of reservoir waterflooding. As a result of reservoir exploitation using the primary and the secondary method, approx. 50% of oil remains in the reservoir [14].

WAG (water-alternating-gas) is the alternating injection of gas and water into a reservoir allowing for increase of its oil recovery coefficients. The use of this method allows also for the reduction of negative results of the use of the extremely popular secondary method, that is waterflooding of reservoir or injection of gas. The use of WAG allows for the limitation of water production as well as the reduction of gas-to-oil ratio in production wells. In addition, the use of CO_2 as the injected gas, increases the displacement effects due to the miscible displacement mechanism occurring in specified reservoir conditions [20]. On the other hand, alternating injection of gas and water at the same time allows to reduce the problems resulting from excessive water production.

Currently, WAG with the use of vertical, standard horizontal as well as bilateral wells is used all around the world [2, 5, 10, 11, 22], and the use of CO_2 in the WAG process allows for the improvement of the reservoir recovery coefficients [3, 9, 13, 23, 24].

The paper consists of two parts. The purpose of the first part [21] was the analysis and optimization of EOR (Enhanced Oil Recovery) methods of water and gas injection by bilateral wells applied to a synthetic reservoir. Based on the conclusions of the first part, this second part of the study includes an analogical analysis made for a real reservoir model. As in the first part, particular attention was paid to various versions of WAG (including SWAG) as the most promising from amongst EOR methods of oil reservoir production [1, 4, 6, 7, 8, 12, 16–19].

Petrel and Eclipse 300 software by Schlumberger [15] were used in this study.

Characteristics of real reservoir models

This part of the study uses a segment of an existing "Black Oil" type model of a real reservoir that was converted to a compositional type for the purpose of this work. As a result, the models with the following parameters were obtained:

- total area: 6 × 4.8 km^2,
- model type: single porosity and permeability,
- lateral dimensions: 60 × 48 blocks, 100 × 100 m each,
- layer structure: 15 layers,
- number of active blocks: 14919,
- original depth of contacts:
  - oil-water: 3282 m below the sea level,
  - gas-oil: 3178 m below the sea level,
- initial reservoir pressure i 426.5 bar (at 3178.1 m below the sea level),
- reservoir temperature (constant): 126.8°C,
- total pore volume: 48.80 million m^3,
- average values of the parameters:
  - porosity: 0.14,
  - horizontal permeability: 23.63 mD,
  - vertical permeability: 2.36 mD.

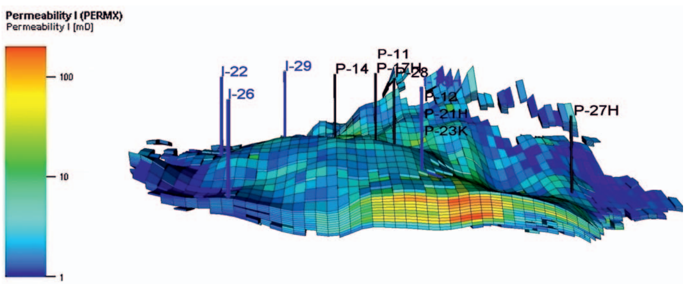

Fig. 1. View with a vertical section of the real reservoir model

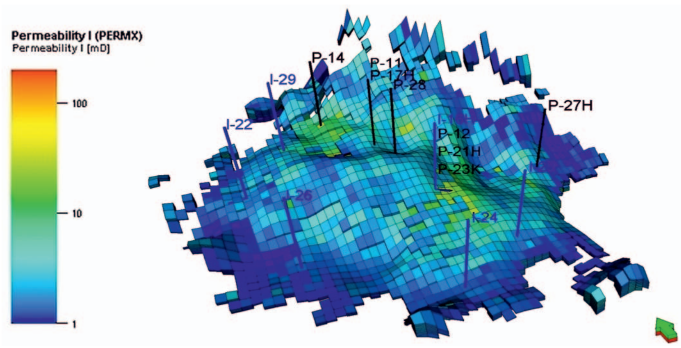

Fig. 2. View of the top layer of the real reservoir model

The prepared simulation models of a real oil reservoir with the above listed parameters were used to perform simulation forecasts. The study presents the results for:

- a base case (with no injection),
- cases with injection of water,
- cases with alternating injection of water and CO_2 (WAG),
- cases with simultaneous injection of water and CO_2 (SWAG version using simultaneous injection of water and CO_2 through separate sections of vertical wells i.e. water through the upper section and CO_2 through the lower section of a vertical well),
- cases with additional injection wells.

Spatial view for the above described models is shown in Figure 1 and 2.

The chemical composition of the oil and gas includes CO_2 component. Parameters of the reservoir fluid were assumed from the real oil reservoir.

The following assumptions were made for the simulation tasks presented below:

- control of the production rate for individual production wells,
- minimum production rate for a well, q_{eco} = 18.39 Nm^3/d,
- maximum gas-to-oil ratio, GOR_{max} = 1867.5 Nm^3/Nm^3 (when this value was exceeded the production rate of the well was reduced),
- maximum acceptable depression at the bottom-hole, $\Delta P = 0.1 \cdot P_{res}$, (where P_{res} is average reservoir pressure),

- minimum wellhead pressure, P_{wh} = 80 bar,
- injection of displacement media in the amount of the produced fluids volume (so-called voidage replacement),
- for cases where water was injected, the maximum water injection rate by a single well, $q_{w,inj,max}$ = 1500 Nm^3/d,
- for cases where CO_2 was injected, the maximum CO_2 injection rate, $q_{g,inj,max}$ = 50 000 Nm^3/d,
- the scheme of the wells used is based on the existing set of wells (Figure 1 and 2) as well as proposed new injection wells to be presented below,
- existing production wells: P-11, P-12, P-14, P-17H, P-21H, P-23K, P-27H, P-28,
- existing injecting wells: I-16H, I-22, I-24, I-25, I-26, I-29,
- maximum bottom-hole pressure for injection wells: in the range of P_{bhp} = 430÷475 bar,
- forecast duration limit: 26 years.

Results of real reservoir models simulations

Base cases

Similar to the synthetic reservoir models, a base case was prepared for the purpose of comparison, in which operation of eight production wells (shown in Figure 1 and 2) was assumed. In this case, as a result of the reservoir pressure drop caused by fluids production from the reservoir, and therefore the wellhead pressure drop, the oil production rate was gradually decreased to the economic limit of q_{eco} = 18.39 Nm^3/d finally resulting in the well being shut. Thus the production process ended in 2044, and by that time N_p = 4.93 million Nm^3 of oil was produced, which corresponded to 18.17% of recovery coefficient (Table 1). The original initial oil saturation is shown in Figure 3, while the analogous distribution at the end of the production forecast for the above base case is presented in Figure 4 where a drop of oil saturation associated with the occurrence of gas in the selected layer of the simulation model can be seen.

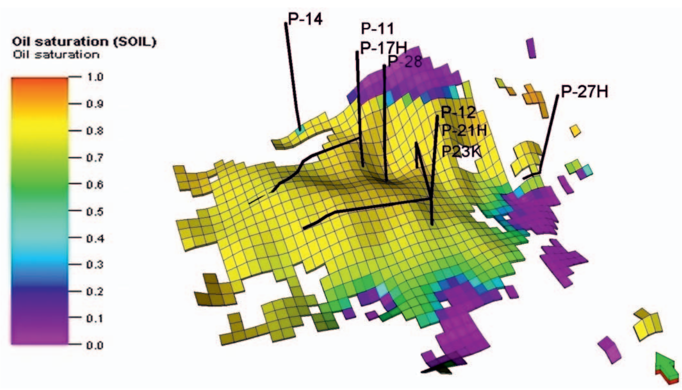

Fig. 3. Oil saturation in the selected layer of the model at the beginning of the production forecast (2017)

Cases with waterflooding

For the purpose of comparison, case IA was constructed, which assumes the commencement of waterflooding on 1.11.2017.

The water injected in the amount corresponding to production fluids volume from the reservoir was supposed to maintain reservoir pressure. As the water production rate was increasing due to the grooving water-cut and the injection rates were limited by the maximum allowed bottom-hole pressure in injecting wells, the average reservoir pressure was not maintained at the required level and, as a consequence, the well-head pressure of the production wells was also decreasing and eventually limited by the minimum allowable pressure of P_{wh} = 80 bar. This was the direct reason for the reduction of the oil production rate. However, almost all production wells were operating until the end of the forecast, i.e. until 2044, reaching the total production level of N_p = 12.37 million Nm^3 corresponding to the recovery coefficient of 46.16% (Table 1). The above described method of immiscible displacement led to the recovery of oil from the reservoir with final oil saturation presented in Figure 5.

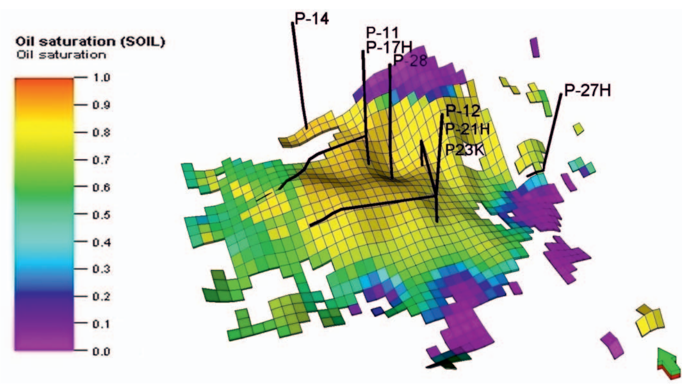

Fig. 4. Oil saturation in the selected layer of the model at the end of the production forecast (2044); Base case

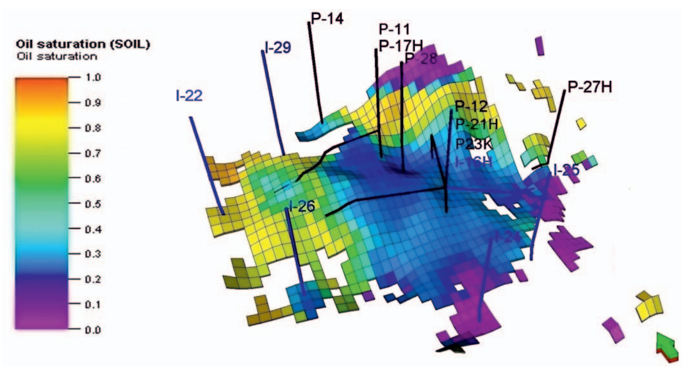

Fig. 5. Oil saturation in the selected layer of the model at the end of the production forecast (2044); Case IA

Cases with alternating injection of water and gas (WAG)

In case IIA the method of alternating injection of water and CO_2 in cycles of 1 month each, with additional assumption of three (out of 6) wells injecting water and, at the same time, the other three injecting CO_2 with fluid switching from cycle to cycle. This assumption, as in the case of the synthetic reservoir models, allowed the elimination of pressure fluctuations in the reservoir as well as keeping the demand for CO_2 and water constant.

The assumption of alternating injection of CO_2 and water, limited the number of wells injecting water at the same time. In addition, the assumed limit for the maximum allowed bottom-hole pressure in the injection wells, made the reservoir voidage replacement ineffective and a consequent reservoir pressure reduction.

The use of CO_2 as well as the above limitation for water injection resulted in slower and reduced inflow of water to production wells, with a simultaneously increased inflow of gas compared to case IA with injection of water alone. As a result of the method used, the production wells were producing oil with lower water-cut and, at the same time, higher gas-to-oil ratio compared to Case IA. The total oil production amounted to N_p = 11.23 million Nm^3, which is smaller than the result for Case IA. The corresponding recovery coefficient was 41.92% (Tab. 1). Gas production remained at an unchanged level. It should be noted that due to the injection of CO_2 (in the amount of G_{inj} = 1.11 billion Nm^3) the water mobility and at the same time its total production was limited to the level of W_p = 5.95 million Nm^3 with simultaneous reduction of injection water to the amount of W_{inj} = 16.57 million Nm^3 (Table 1). Oil saturation distribution for the selected layer at the end of the production forecast for Case IIA is presented in Figure 6 which directly shows the zones around the injection wells where the total recovery of oil took place due to the phenomenon of miscible oil displacement with CO_2.

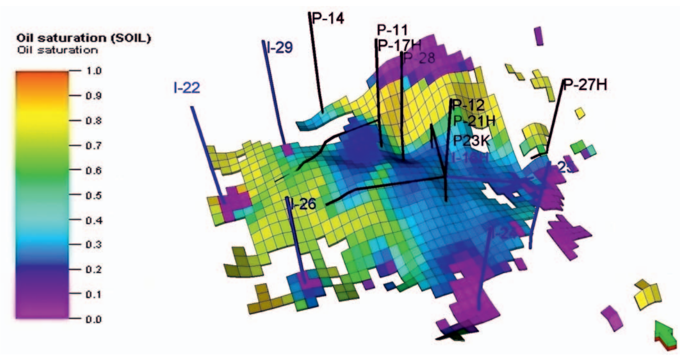

Fig. 6. Oil saturation in the selected layer of the model at the end of the production forecast (2044); Case IIA

Cases with simultaneous injection of water and gas (SWAG)

Similarly to the synthetic reservoir models, a case assuming the use of the SWAG method with selective and simultaneous injection of water and CO_2 (water through upper sections and CO_2 through lower sections of the injection wells) was simulated.

As a result of the division of the injection well completion interval into smaller sections and, at the same time, reduction of the length of the injection interval for each of the displacing media (water and CO_2), a faster growth of pressure in the lower sections injecting CO_2 occurred. The shorter injection interval also had a significant impact on the reduction of the CO_2 injection rate and, to a lesser extent, on the reduction of the water injection rate.

Higher reservoir pressure compared to the case with the traditional WAG method as well as the selective injection of CO_2 and water had a positive effect on the total production of oil, which amounted to N_p = 12.74 million Nm^3 (Table 1), and the recovery coefficient amounted up to 47.54% (Table 1) with maintained gas production, and a 5-fold drop of the amount of the injected CO_2 to the level of G_{inj} = 0.21 billion Nm^3 (Table 1). Continuous injection of water in the amount of W_{inj} = 37.86 million Nm^3 (Table 1) corresponded to a 2-fold increase compared to the case with the WAG method. Similarly, water production at the level of W_p = 21.90 million Nm^3 (Table 1) increased by the factor of 4. Despite the 5-fold reduction of CO_2 injection we were able to observe an increase of the size of the zone from which the total recovery of oil due to miscible displacement occurred (Figure 7).

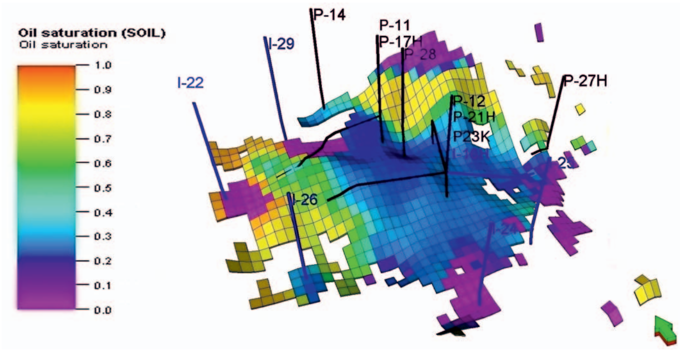

Fig. 7. Oil saturation distribution in the selected layer of the model at the end of the production forecast (2044); Case IIIA

Case with additional injection wells

Cases IB, IIB, IIIB constitute a group of cases where the production was performed with the application of respectively: waterflooding, alternating injection of CO_2 and water (WAG), and simultaneous injection of CO_2 and water (SWAG) with modification of the location of an injection well (I-32 instead of I-22) as well as the addition of two new injection wells (I-33, I-34). Location of the new injection wells is shown in Figure 8.

Addition of these two new injection wells allowed for the increase of the injection rates, as well as for the conducting of the injection process in a more uniform manner, limiting and delaying injected fluid migration to the production wells.

In Case IB compared to Case IA total oil production increased from 12.37 to 12.91 million Nm^3, corresponding to the recovery coefficient increase from 46.16% to 48.17% (Table 1). A small increase occurred also for the other results. The effect of an extended reservoir zone covered by waterflooding with the use of the larger number of injection wells, is shown in Figure 9.

Similarly, in case IIB compared to case IIA total oil production from the reservoir increased from 11.23 to 11.80 million Nm^3, corresponding to the recovery coefficient increase from 41.92% to 44.04% (Table 1). A small increase occurred as well for the other results. The effect of an extended reservoir zone covered by the miscible displacement process (in WAG method) using the larger number of injection wells is shown in Figure 10.

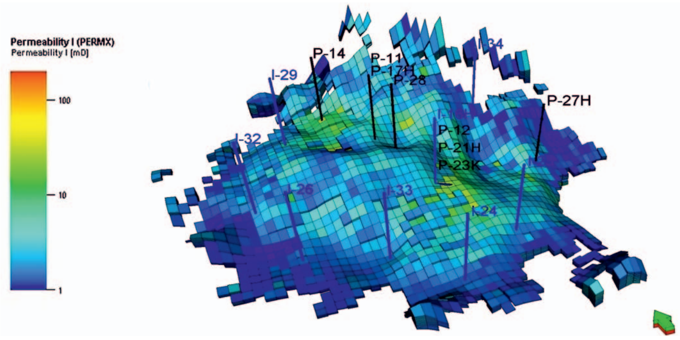

Fig. 8. Real reservoir model with additional injection wells – Base cases, IB, IIB, IIIB

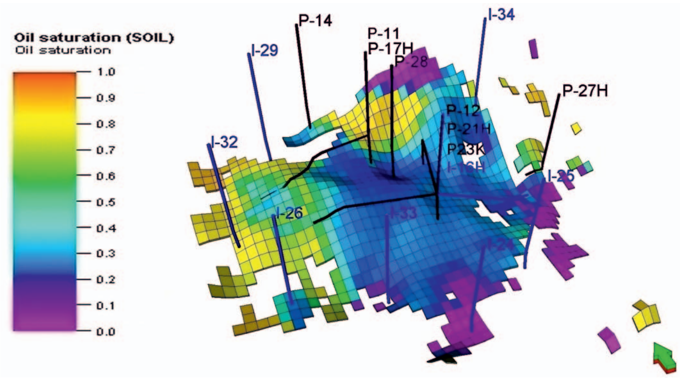

Fig. 9. Oil saturation distribution at the end of the production forecast (2044); Case IB

In Case IIIB compared to Case IIIA total oil production from the reservoir increased from 12.74 to 13.36 million Nm^3, corresponding to the recovery coefficient increase from 47.54% to 49.88% (Table 1). A small increase occurred also for the other results. Distribution of oil saturation at the end of the production forecast for Case IIIB is shown in Figure 11 which presents a larger zone covered by miscible displacement effect with the use of the SWAG method using a larger number of injection wells compared to Case IIIA.

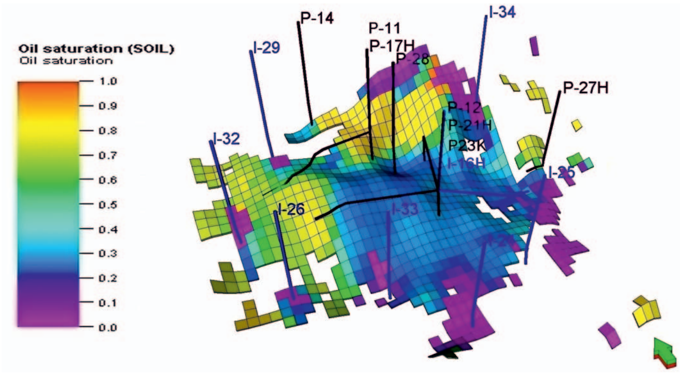

Fig. 10. Oil saturation distribution at the end of the production forecast (2044); Case IIB

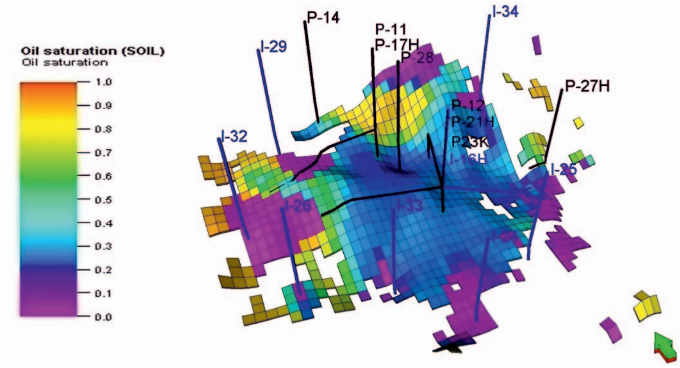

Fig. 11. Oil saturation distribution at the end of the production forecast (2044); Case IIIB

The best result was achieved for the SWAG method in case IIIB with the use of 8 injection wells and 8 production wells (Figure 12). In this case 13.36 million Nm^3 of oil was produced (recovery coefficient of 49.88%) with the injection of water at the level of 43.87 million Nm^3 and CO_2 in the amount of 0.45 million Nm^3. At that time, 2.61 million Nm^3 of gas and 27.45 million Nm^3 of water was produced from the reservoir (Table 1). High recovery coefficient obtained for the system of production wells surrounded by injection wells in the SWAG method resulted from:

- effective recovery of oil in the miscible displacement process,
- slower migration of the injected water (slower watering-out) to the production wells and, as a result, a longer period of effective production,
- slower migration of the injected CO_2 (smaller gas-to-oil ratios) to the production wells and, as a result, a longer period of effective production,
- extended contact of CO_2 with the bottom layers of the reservoir,
- larger volume of injected water and, consequently, more efficient maintenance of the reservoir pressure above minimum miscibility pressure, allowing for the longer duration of miscible oil displacement by the solvent (CO_2).

The above reasons explain the increased production of oil from the reservoir with the use of the SWAG method compared to the other methods of oil reservoir exploitation. It should be noted, that none of these methods have been individually optimized in terms of ratio of injected fluids, as the amounts of injected fluids resulted from general assumptions – injection of water was supposed to balance the production of fluids from the reservoir. At the same time it was limited, due to the low permeability of rocks, by the maximum allowable bottom-hole pressure and injection of CO_2 it could not supplement insufficient water injection.

Detailed results of the amounts of produced and injected fluids for each case are shown in Table. 1.

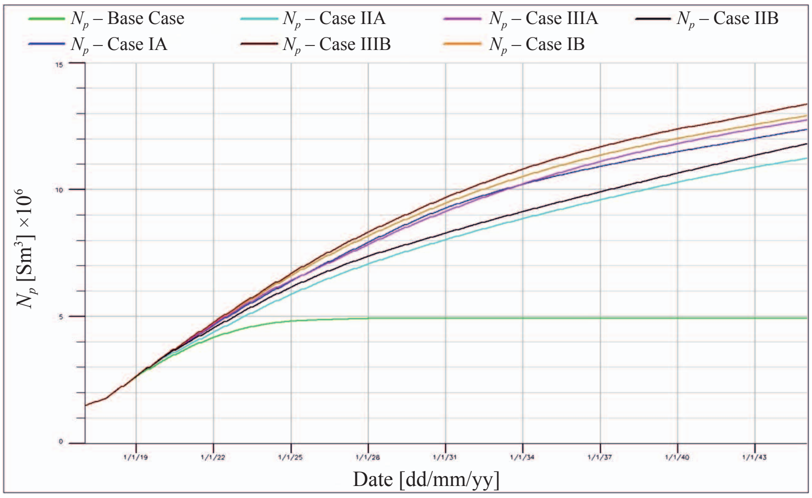

Fig. 12. Total oil production. Comparison of all cases

Table 1. Basic results for real reservoir model

Case	Recovery method	No. of injection wells	Oil production total N_p	Gas production total G_p	Water production total W_p	Gas injection total G_{inj}	Water injection total W_{inj}	Recovery coefficient
			[million Nm^3]	[billion Nm^3]	[million Nm^3]	[billion Nm^3]	[million Nm^3]	[%]
Base	Primary	6	4.93	1.70	0.02	0.00	0.00	18.17
IA	Water injection	6	12.37	2.22	25.84	0.00	41.97	46.16
IIA	WAG	6	11.23	2.22	5.95	1.11	16.57	41.92
IIIA	SWAG	6	12.74	2.28	21.90	0.21	37.86	47.54
IB	Water injection	8	12.91	2.32	26.86	0.00	43.06	48.17
IIB	WAG	8	11.80	2.52	7.40	1.50	18.36	44.04
IIIB	SWAG	8	13.36	2.61	27.45	0.45	43.87	49.88

Summary of simulation results for the real reservoir models

1. The application of water injection causes an effective maintenance of the reservoir pressure and, as a result, a significant increase of recovery coefficient from 18.17% (Base Case) to 46.16% (Case IA) achieved for high water production and high water–cuts reaching even 95%.
2. The application of the WAG method with the use of alternating injection of water and CO_2 results in the significant effect of miscible displacement. Unfortunately, the system of injection wells does not allow for the injection of water at amounts comparable to those of the waterflooding case, which causes a drop of the reservoir pressure, and, as a consequence, lower oil recovery coefficient of 41.92% (Case IIA) and lower water production (5.95 million Nm^3 vs 25.84 million Nm^3 in Case IA).
3. The application of the SWAG method with the use of simultaneous injection of water and CO_2 reduces the effects of fast increase of gas-to-oil ratio in production wells with simultaneous improvement of oil recovery from the bottom layers of the reservoir resulting in the recovery coefficient of 47.54% (Case IIIA).
4. The effectiveness of each of the methods is based on the properly selected locations of injection wells (and there completion intervals) that guarantee large injectivity indices and optimum distance between them and the production wells.
5. The use of additional production wells allows for the coverage of a larger reservoir area by the analyzed methods of oil displacement and, at the same time, enhances the recovery factor up to 48.17%, 44.04%, and 49.88% for Case IB, IIB, and IIIB, respectively.

Summary and conclusions

Within the scope of the study described in Part I and Part II the following tasks were accomplished:

- Multi-case simulation forecasts of the selected EOR methods were conducted using the models of both synthetic and real reservoirs.
- Detailed analysis of the results of the above simulations was performed.

The following conclusions could be drawn from the conducted simulation forecasts and performed analyses:

1. Exploitation of oil reservoirs with the use of waterflooding method and EOR methods allowing for the maintenance of the reservoir pressure, results in more effective oil recovery due to the elimination of a secondary gas cap and consequent large gas-to-oil ratios in the production wells.
2. Water injection to the reservoir allows for a larger reservoir volume to be covered by the displacement effects than in the case of gas injection, however it does not guarantee a larger recovery of oil.
3. Migration of CO_2 through the oil zone with simultaneous maintenance of the reservoir pressure above the minimum miscibility pressure allows for the achievement of the miscible displacement effect increasing the recovery coefficient of oil from the reservoir rocks.
4. Modification of the completion intervals in the injection wells in the case of reservoirs without a clear anisotropy and heterogeneity has no significant impact on the oil depletion from such reservoirs.
5. No significant variations of the oil production effects from the lengths of WAG cycles were found. However, the ratio of the injected water volume to the injected gas volume in the WAG method may be quite significant for the optimum results of the method.
6. Each EOR method and each reservoir require individual studies by appropriate modeling to obtain an optimum solution with respect to total production and injection volumes.
7. Miscible displacement of oil by injected CO_2 becomes a significant mechanism to contribute to the effective oil recovery for the WAG or SWAG method. For this mechanism to be active it is important to maintain the reservoir pressure above minimum miscibility pressure of the system of reservoir oil and injected CO_2 during the longest possible part of the process.
8. Summary table (Table 1) for the simulation results obtained for the model of a real oil reservoir shows that the WAG/SWAG method with the use of CO_2 may be an effective alternative for the currently used methods.

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