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

The paper presents analysis of the selected EOR methods based on the results of reservoir simulations with particular attention paid to WAG method and its SWAG variation consisting in simultaneous and selective injecting of water and CO_2 (water through the upper section, CO_2 through the lower section of the injector). Reservoir simulations have been performed on two models of synthetic reservoir: one with standard permeability equal to the average permeability of the largest Polish reservoir and the second one with reduced permeability. Forecasts of oil production with the use of the primary method, waterflooding method as well as WAG and SWAG methods have been performed for each of these models. For each of these methods, the cases of oil production by a vertical, standard horizontal and by bilateral well with two sections situated one above the other were considered. 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 it. The paper presents a detailed analysis of the reservoir exploitation for each of the cases. Results for total amounts are presented in the table, and the qualitative assessment is presented based on simulation results including distribution of oil saturation in the reservoir at the end of exploitation process.

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 I – model złoża syntetycznego

W pracy w oparciu o wyniki symulacji złożowych przedstawiono wybrane metody EOR ze szczególnym uwzględnieniem metody WAG i jej odmiany SWAG polegającej na równoczesnym i selektywnym tłoczeniu wody i CO_2 (wody górną sekcją odwiertu zatłaczającego, CO_2 dolną jego sekcją). Symulacje złożowe przeprowadzono na dwóch modelach syntetycznego złoża: jednego o standardowej przepuszczalności, tj. równej średniej przepuszczalności dla jednego z największych polskich złóż i drugiego o przepuszczalności zredukowanej. Dla każdego z tych modeli przeprowadzono prognozy wydobycia ropy przy użyciu metody pierwszej, metody nawadniania oraz metod WAG i SWAG. Dla każdej z powyższych metod rozpatrzono przypadki wydobycia ropy przez odwiert pionowy, standardowy horyzontalny oraz bilateralny o dwóch sekcjach znajdujących się jedna nad drugą. 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 eksploatacji złoża dla każdego wariantu. Wyniki dla sumarycznych wielkości zestawiono w tabeli, a ocenę jakościową przedstawiono w oparciu o podstawowe wyniki symulacji, w tym rozkłady nasycenia ropą w złożu na koniec eksploatacji złoża.

Słowa kluczowe: EOR (wspomagane wydobycie ropy), WAG (naprzemienne zatłaczanie wody i gazu), SWAG (jednoczesne, naprzemienne zatłaczanie wody i gazu), zatłaczanie CO_2, wypieranie mieszające, 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 secondary method of reservoir waterflooding. As a result of the reservoir exploitation with the use of the primary and the secondary method, approx. 50% of oil remains in the reservoir [14].

WAG (water-alternating-gas) is alternating injection of gas and water into reservoir allowing for increase of its oil recovery coefficients. The application of this method allows also for 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 limitation of water production as well as 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 [19]. On the other hand, alternating injecting 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, 20], and the use of CO_2 in WAG process allows for improvement of the reservoir recovery coefficients [3, 9, 13, 21, 22]. Particular attention was paid to various versions of WAG method as the most promising ones from among EOR (Enhanced Oil Recovery) methods of oil production. The studies varied from analytical models [18] to an overview of varieties of the WAG method used in the oil production [12]. In some works the focus was on the position of vertical wells or the ratio of injected CO_2 to water in the WAG scheme [4]. Another work focused on comparison of WAG with continuous CO_2 injection [17]. For further improvement of oil recovery efficiency horizontal wells were used [1, 6, 7, 8, 16].

The paper consists of two parts. This first part constitutes the analysis of methods of injecting water and gas for the model of a synthetic reservoir. The basic criterion used to compare various production scenarios is the total oil production (and equivalently recovery factor). Based on the conclusions of this part, the implementation of analogous EOR methods in models of a real reservoir was applied and analyzed in the second part of the work and is reported in the subsequent paper. Results of this work also indicate the usefulness of simulation models for analysis and selection of EOR methods as applied to oil reservoir production.

The study uses reservoir modeling and simulation software – Petrel and Eclipse 300 by Schlumberger [15].

Characteristics of synthetic reservoir models

For better understanding and description of phenomena occurring during EOR processes with the use of water and gas, three-dimensional models of a synthetic reservoir made of 16800 active blocks creating a regular cube was constructed. A grid of 31 × 31 × 20 model blocks is homogeneous and forms a model with the horizontal sizes of 2000 × 1000 m. The model is also characterized by a homogeneous porosity and permeability. The model allows for the presence of underlying water. The reservoir fluid (oil with gas in solution) was modeled with the compositional simulations. The fluid composition is that of a real oil reservoir operated in Poland.

The view of the model with cross-section, location of a bilateral production well and vertical injection wells, as well as initial distribution of oil saturation is shown in Figure 1.

Basic assumptions of the production process simulated with these models follow:

- initial conditions: p_{ini} = 557 bar, T_{res} = 122°C at the depth of 3085 m,
- nominal production of oil from a well, q_o = 750 SCm^3/d,
- injection of displacement media in the amount equal to produced fluids volume (the so-called voidage replacement),
- for cases where water is injected, the maximum water injection rate by a single well, $q_{w,inj,max}$ = 1500 SCm for cases where CO_2 is injected, the maximum CO_2 injection rate by a single well, $q_{g,inj,max}$ = 50000 SCm^3/d,
- well setup applied: so-called 5-point scheme with 4 vertical injection wells located in the corners of the model and a production well in the model center (Figures 1, 2, 3),
- minimum rate of oil production from a well, q_{eco} = 18.34 SCm^3/d,
- maximum water cut, WCT_{max} = 0.95 SCm^3/SCm^3 (after this value was exceeded the well is closed),
- maximum gas-to-oil ratio, GOR_{max} = 2000 SCm^3/SCm^3 (after this value was exceeded the production rate is reduced),
- maximum acceptable depression at the bottom-hole of production wells, ΔP = 50 bar,
- minimum bottom-hole pressure in production wells, $P_{bhp,min}$ = 225 bar,
- maximum bottom-hole pressure in injection wells, $P_{bhp,max}$ = 612.7 bar (110% × p_{ini}),
- forecast duration limit: 30 years.

As the control parameters, in particular well limiting pressures, refer to bottom-hole values then no hydraulic models of production/injection wells, relating bottom-hole to well-head quantities, were used.

Results of synthetic reservoir models simulations

For the purpose of this work, simulation forecasts of oil production were performed for the models with horizontal permeability equal to an average horizontal permeability of one of the Polish reservoirs, i.e. k_h = 21.42 mD and vertical permeability, k_v = 2.14 mD in four groups of cases for varying methods of production, i.e.:

- simulations of primary method of production – base cases,
- simulations with secondary method using waterflooding – cases marked with "I",
- simulations with the use of standard WAG – cases marked with "II",
- simulations with the use of SWAG method (Simultaneous Water Alternating Gas). Cases with simultaneous injection of water and CO_2 through separate sections of vertical wells were simulated i.e. water through the upper section and CO_2 through the lower section of vertical injection wells – cases marked with "III",

For all of the above groups, the following cases were considered for various types of the production well:

- vertical well – cases marked with letter "A",
- standard horizontal well – cases marked with letter "B",
- bilateral (double-bottom) well with horizontal sections located at a distance of 20 m one below the other – cases marked with letter "C",

Models with standard permeability (k_h = 21.42 mD)

Base cases

According to the above, the base Cases A, B, C were prepared. In Cases B and C the production wells restricted by the limits listed in the general assumptions were producing oil with the assumed rate of q_o = 750 SCm^3/d for 3 years and then they reduced the rate of oil production due to the limiting bottom-hole pressure P_{bhp} = 225 b down to the minimum economic rate of q_{eco} = 18.34 SCm^3/d. In the base Case A, the vertical well limited by the maximum acceptable depression at the bottom-hole, ΔP = 50 b, could not produce at the assumed rate, as a consequence the exploitation time in that case is extended in comparison to Cases B and C. The recovery coefficients amounted to 14.83%, 17.41% and 16.30% respectively for Cases A, B and C. The higher production of oil by the standard horizontal well was caused by the reduced gas-to-oil ratio compared to the case with the bilateral well. Figure 2 shows a distribution of oil saturation for base Case C at the end of the production forecast.

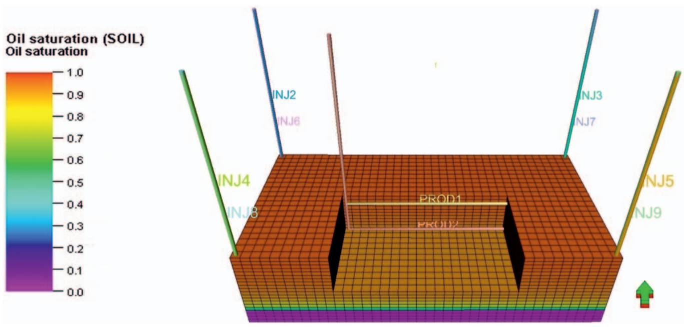

Fig. 1. Three-dimensional model of a synthetic reservoir produced by a bilateral well. Initial oil saturation

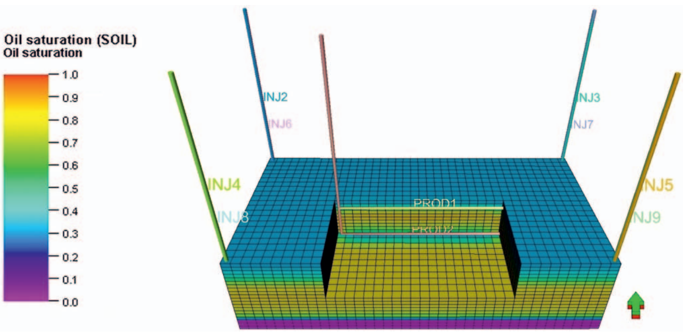

Fig. 2. Oil saturation in the reservoir at the end of the production forecast. Base Case C. Standard permeability k_h = 21.4 mD

Cases with water injection

Similarly to the base cases, the cases of oil production supported by water injection – Cases IA, IB, IC – were simulated.

In Case IA, similarly to the base case, the factor limiting the oil production was the maximum acceptable depression at the bottom-hole. Due to the constant injection of water, the well reduced its oil production while the water production was increasing. In Cases IB, IC the wells were producing oil at the assumed rate throughout the whole period of the production forecast. The intensive operation of the injection wells led to faster inflow of water into the production well and its watering-out, which caused a drop of the bottom-hole pressure and consequently the reduction of oil production rate down to the economic limit and finally well shutting.

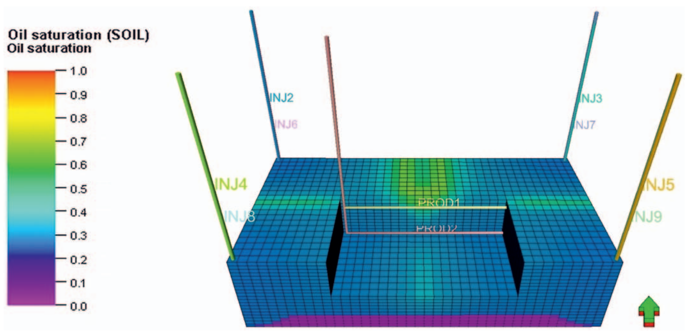

Fig. 3. Oil saturation in the reservoir at the end of the production forecast. Case IC. Standard permeability k_h = 21.4 mD

Recovery coefficients amounted to 62.32%, 59.83% and 60.22% respectively for Cases IA, IB and IC. The highest production of the vertical well was caused mainly by its larger distance from the injection wells and its less intensive operation (lower rate of oil production), which resulted in extended time of exploitation. However, the differences between this recovery coefficients are rather small and, thus, do not indicate any dominating method at least from the technological point of view. Oil saturation at the end of the production forecast for Case IC is shown in Figure 3 which presents the effect of immiscible oil displacement with water covering almost the entire reservoir, leaving residual oil (S_{owcr} = 30%) in the rocks were the oil displacement with water occurred. Maintaining the reservoir pressure also caused no secondary gas cap to appear.

Cases with alternating injection of water and gas (WAG)

Another group of cases are the ones with alternating injection of water and CO_2 – Cases IIA, IIB, IIC. These cases assume injecting of water and CO_2 in cycle duration of 1 month each with additional assumption of two wells injecting water and, at the same time, the other two injecting CO_2 with fluid switching from cycle to cycle. This assumption allows elimination of pressure fluctuations in the reservoir as well as keeping the demand for CO_2 and water constant.

In Case IIA, similarly to base Case A and Case IA, the vertical well was not able to work with the assumed rate of oil production. As a consequence, its operation was prolonged to almost 30 years. Finally, the well was closed by the economic limit reached due to the rate reduction by the limiting gas-to-oil ratio. In Cases IIB and IIC, similarly to Cases IB and IC, an inflow of water into the production well occurs a few years later than in Case IIA (due to the injection of CO_2), causing higher production of oil from the reservoir. The recovery coefficients amount to 80.01%, 74.71% and 74.81% respectively for Cases IIA, IIB and IIC. Similarly to the cases with waterflooding, the recovery coefficients in the cases with vertical well are higher due to a lower rate of oil production achieved by the well as well as a greater distance between the vertical production well and the injection wells. Figure 4 shows an oil saturation distribution forecast for Case IIC at the end of the production forecast. It presents the results of both miscible and immiscible displacement – one can distinguish a zone where water displaced oil leaving its saturation at the residual level and another zone where oil was completely displaced by CO_2.

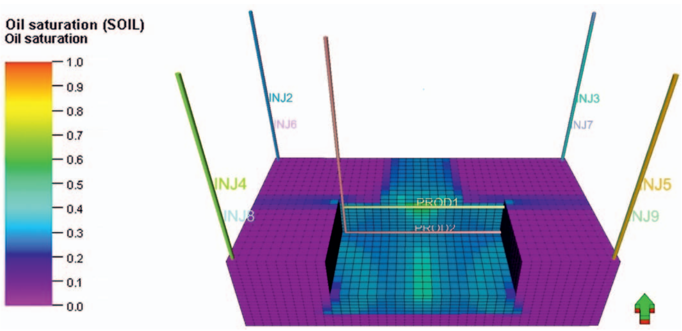

Fig. 4. Oil saturation in the reservoir at the end of the production forecast. Case IIC. Standard permeability k_h = 21.4 mD

Cases with simultaneous injection of water and gas (SWAG)

The last group of cases refers to the variation of the previously described WAG method that assumes simultaneous and selective injection of water and CO_2 to the reservoir, i.e. CO_2 through lower sections of injection wells and water through their upper sections. The SWAG cases allowed additional reduction of both water and gas mobility consisting in migration of the injected gas towards the reservoir top layers thus limiting the relative permeability of water and migration of water towards the reservoir bottom layers thus reducing the relative permeability of gas. In these variations, some kind of mutual "trapping" of displacing fluids with simultaneous improvement of the effective oil displacement occurs.

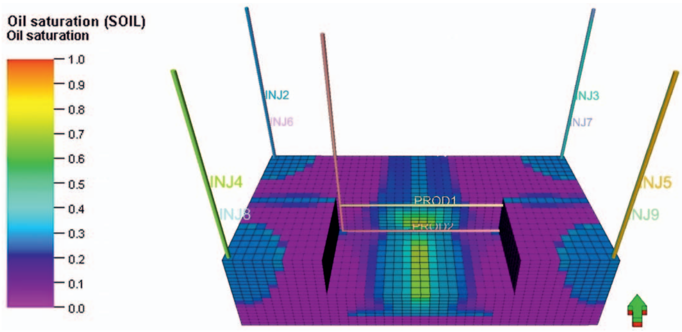

Fig. 5. Oil saturation in the reservoir at the end of the production forecast. Case IIIC. Standard permeability k_h = 21.4 mD

As a result, the use of SWAG causes reservoir pressure to be maintained at the relatively high level and oil to be effectively displaced. These effects result in the increase of the recovery coefficients for Cases IIIA, IIIB, IIIC up to the level of, respectively, 93%, 83.52%, 82.75%. The higher total oil production by the vertical well is caused by less intensive operation compared to the horizontal wells cases as well as its larger distance from the injection wells, and therefore later migration of the injected fluids to the production well in the assumed 5-point injection scheme. The effect of both immiscible and miscible displacement for Case IIIC is presented in Figure 5 where a narrowed zone of residual oil can be observed in the area of the production well in relation to Case IIC, as well as residual oil in the area of the upper parts of injection wells surroundings.

Summary of simulation results for the standard permeability models

The best result was achieved for SWAG method in Case IIIA in which 4.85 million SCm^3 of oil was produced (recovery coefficient of 93%) with injection of water at the level of 6.15 million SCm^3 and CO_2 in the amount of 1.99 million SCm^3. In this case 2.14 million Nm^3 of gas and 1.45 million SCm^3 of water is produced from the reservoir. It should also be pointed out that Case IIIA is characterized by a significant extension of the production time in comparison to Cases IIIB and IIIC (27 vs 17 years). The high value of oil recovery coefficient in the vertical well SWAG case under analysis has several reasons:

- selective injection of CO_2 and water contributes to the reduced effective migration of the injection fluids to the production well,
- the distance between injection wells and the vertical production well is larger than the distance between injection wells and the horizontal production well,
- less intensive operation (lower rate of oil production) of the vertical production well results in lower total injection of water to the reservoir and, consequently, later watering-out of the production well compared to the cases with horizontal production wells and also lower gas-to-oil ratio observed in this well.

It is worth noting that lower production rate and longer production period in Case IIIA may turn out to be disadvantageous when economic factors are considered in addition to the technological ones.

Detailed results concerning the amount of produced and injected fluids for every case of the models with standard permeability are shown in Table 1.

Table 1. Basic results for standard permeability models, k_h = 21.4 mD

Case	Recovery method	Production well	N_p [million SCm^3]	G_p [billion SCm^3]	W_p [million SCm^3]	G_{inj} [billion SCm^3]	W_{inj} [million SCm^3]	Recovery coefficient [%]
Base A	Primary	vertical	0.77	0.29	0.24	0.00	0.00	14.83
Base B		horizontal	0.91	0.27	0.22	0.00	0.00	17.41
Base C		bilateral	0.85	0.29	0.14	0.00	0.00	16.30
I A	Water injection	vertical	3.25	0.55	2.12	0.00	6.43	62.32
I B		horizontal	3.12	0.67	4.96	0.00	8.95	59.83
I C		bilateral	3.14	0.68	4.45	0.00	8.47	60.22
II A	WAG	vertical	4.17	1.36	1.71	1.06	6.33	80.01
II B		horizontal	3.90	1.16	4.13	0.57	8.49	74.71
II C		bilateral	3.90	1.18	4.20	0.58	8.62	74.81
III A	SWAG (water through the upper section, CO_2 through the lower section)	vertical	4.85	2.14	1.45	1.99	6.15	93.00
III B		horizontal	4.36	1.82	4.25	1.28	8.95	83.52
III C		bilateral	4.32	1.83	4.31	1.28	8.98	82.75

Models with reduced permeability (k_h = 2.14 mD)

Base cases

Similarly to the models with standard permeability a simulation for three base Cases (primary method) were performed: A', B', C', with different types of the production well.

In base Case A' the vertical well was limited by the maximum acceptable depression at the bottom-hole (ΔP = 50 b) and was not capable of reaching the assumed rate but began to produce oil at the rate of 90 SCm^3/d, which gradually decreased during its 30-years' exploitation period down to the level of 29 SCm^3/d at the end of the forecast. In base Case B', the standard horizontal well reached a limit of the acceptable depression at the bottom-hole a year after starting the production and, consequently, reduced its oil production rate. Next, the minimum of the bottom-hole pressure (P_{bhp} = 225 b) caused further reduction of oil production rate until reaching the economic limit. Operation time for this case amounted to 11 years. In base Case C' both sections of the bilateral well operated with the assumed rates of q_o = 750 SCm^3/d for two initial years of production until achievement of the minimum bottom-hole pressure when the rate gradually decreased. Production by the well is finished after almost 8 years as a result of the rate decreased down to the economic limit.

Recovery coefficients of oil for base Cases A', B' and C' amount respectively to 9.07%, 21.53%, 21.94%. The highest production of oil by the bilateral well is mainly caused by relatively high level of the well opening to the reservoir rock in this case of low permeability reservoir. It should be noted that in this case, the highest production is achieved within the shortest time of reservoir exploitation. Figure 6 shows the distribution of oil saturation for Case C' at the end of the production forecast.

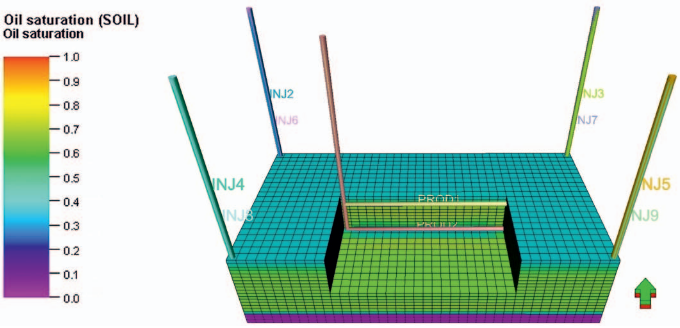

Fig. 6. Oil saturation in the reservoir at the end of the production forecast. Case C' for reduced permeability k_h = 2.14 mD

Cases with waterflooding

Similarly to base cases, three cases of oil production by the secondary method of waterflooding were simulated as Case IA', IB', IC'.

In Case IA,' similarly to base Case A', despite waterflooding, the oil production by the vertical well was limited by acceptable depression as well as the minimum pressure at the bottom-hole. The well started the oil production at the rate of 90 SCm^3/d, which dropped to the level of 41 SCm^3/d over its 30-years' exploitation. In Case IB', similarly to the Case B', the horizontal well maintained the assumed nominal rate of oil production for a year, and then, limited by the depression at the bottom-hole, gradually reduced it so that after 3 years from the beginning it switched into control by the limiting bottom-hole pressure and performed the production for the next 27 years of the forecast with potential continuation in subsequent years according to the existing trend. Similarly to Case IC' the production from both horizontal sections of the production well was reduced after more than 2 years from the beginning as a result of reaching the limiting bottom-hole pressure. Next, the bottom section of the well was watered-out and stopped its operation as a result of the rate reduction down to the economic limit, while the upper section operated until the end of the 30-years' forecast.

Recovery coefficients for Cases IA', IB', IC' amount respectively to 10.48%, 36.74%, 37.09%. Cases IB' and IC' show the highest degree of recovery coefficient, which results mainly from relatively high level of the well opening to the reservoir rock that is especially important in this case of low permeability reservoir. Oil saturation at the end of the production forecast for Case IC' is shown in Figure 7 where the effect of immiscible displacement of oil by water can be seen, that covers a smaller part of the reservoir volume compared to the standard permeability reservoir.

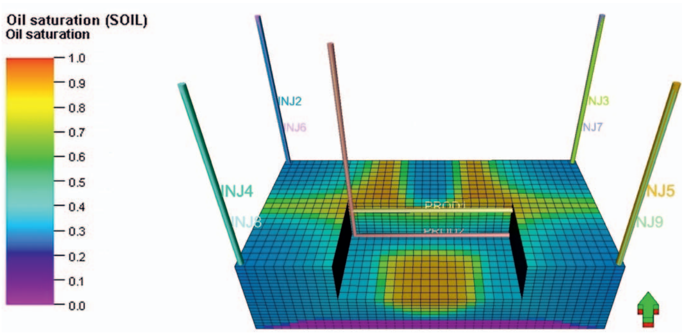

Fig. 7. Oil saturation in the reservoir at the end of the production forecast. Case IC' for reduced permeability k_h = 2.14 mD

Cases with alternating injection of water and gas (WAG)

Another group of cases are the ones with alternating injection of water and CO_2 – Cases IIA', IIB', IIC'. These cases assume cycles consisting of 1 month of water injection and 1 month of CO_2 injection with additional assumption of two wells injecting water and, at the same time, the other two injecting CO_2 with fluid switching from cycle to cycle. As before, this assumption allows elimination of pressure fluctuations in the reservoir as well as keeping the demand for CO_2 and water at constant level.

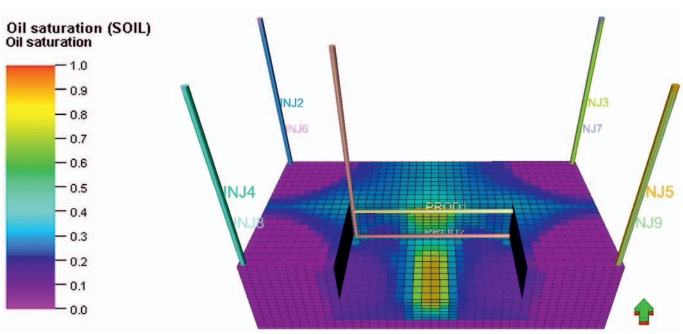

Fig. 8. Oil saturation in the reservoir at the end of the production forecast. Case IIC' for reduced permeability k_h = 2.14 mD

In Case IIA', similarly to base Case A' and Case IA', the vertical well was not capable of operation with the assumed rate of oil production. Its rate was gradually decreasing starting from 80 SCm^3/d down to 43 SCm^3/d at the end of the 20-years' forecast. In Case IIB', after 1-years' operation of the oil production at the assumed rate of 750 SCm^3/d, it dropped initially as a result of the depression limit, and later (after 16 years of exploitation) as the result of the minimum, acceptable bottom-hole pressure. This well can potentially continue production for another couple of years. In Case IIC', both horizontal sections of the production well produced oil with the assumed rate for about 2 years, and then they were gradually limited by the minimum bottom-hole pressure and yet they operated until the end of the 30-years' forecast.

Recovery coefficients for Cases IIA', IIB', IIC' amount respectively to 11.02, 77.51, 75.06%. The highest recovery coefficient is reached by the horizontal well with one horizontal section (Case IIB') and this result is a consequence of lower water production compared to Case IIC'. However, the obtained difference between these two cases is quite small.

Distribution of oil saturation at the end of the production forecast for Case IIC' is shown in Figure 8, which directly presents the size of the zone with completely recovered oil due to the phenomenon of miscible displacement.

Cases with simultaneous injection of water and gas (SWAG)

Cases IIIA', IIIB', IIIC' constitute a group of cases utilizing the SWAG method, that is a modified WAG method with selective and simultaneous injection of water and CO_2 to the reservoir (water to the upper sections and CO_2 to the lower sections of the vertical injection wells).

In case of vertical production well (Case IIIA') the use of SWAG method does not lead to significant differences in the results for oil production compared to the standard WAG method (Case IIA').

On the other hand, in case of the horizontal production well, both standard and bilateral one (Cases IIIB' and IIIC'), a reduction of oil production can be seen compared to similar cases with the standard WAG method (Cases IIB' and IIC'). Utilization of SWAG is characterized by more than 2-fold reduction of the amount of injected water with simultaneous 2-fold increase in the injected CO_2. As a result, an accelerated reservoir pressure reduction occurs, which leads to the reduction of oil production. Also, the water production is reduced by the factor of 2 and the gas production is increased by approx. 30%.

Recovery coefficients for the discussed Cases IIIA', IIIB' and IIIC' amounts respectively to 10.96, 68.40, 66.92%. Distribution of oil saturation at the end of the production forecast for Case IIIC' is shown in Figure 9. This distribution is characterized by clearly weaker effects of oil recovery in miscible displacement process compared to the results of the standard WAG method.

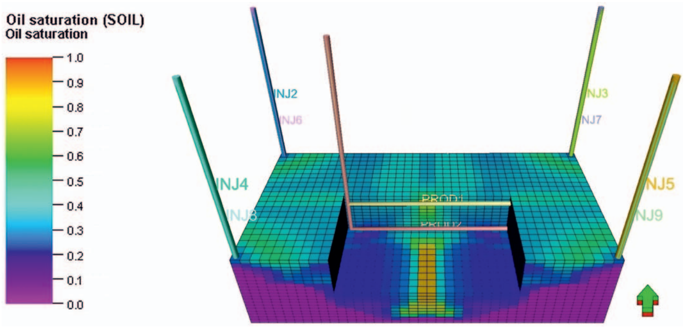

Fig. 9. Oil saturation in the reservoir at the end of the production forecast. Case IIIC' for reduced permeability k_h = 2.14 mD

Summary for the reduced permeability model

The best result was achieved for the standard WAG method in Case IIB' with the use of the standard horizontal production well with singular horizontal section. In this case 4.04 million SCm^3 of oil is produced (recovery coefficient of 78%) with injection of water at the level of 6.12 million SCm^3 and injection of CO_2 in the amount of 1.09 billion SCm^3. At the same time 1.16 billion SCm^3 of gas and 2.90 million SCm^3 of water are produced from the reservoir. The high recovery coefficient obtained by the standard horizontal well in WAG method is caused by the following factors:

- effective recovery of oil by CO_2 in the miscible displacement process,
- increased contact of the horizontal well with reservoir rock (larger drainage zone) compared to cases with a vertical well,
- slower migration of the injected water to the production well (smaller watering-out) and, as a consequence, a longer period of effective production,
- increased volume of the injected CO_2 and, as a result, more effective displacement of oil.

The above reasons explain the increased oil production by the horizontal well in WAG and SWAG methods compared to the cases with the vertical well. It should be noted that WAG method with the use of horizontal well reproduces approximately the results of the depletion obtained for the model with standard (larger) permeability. On the other hand, in the reduced permeability models, the case with the vertical production well achieves significantly lower production in comparison to the model with standard permeability.

Contrary to the model with standard permeability, SWAG method is less effective compared to WAG method. The main reason for this is the less effective miscible displacement mechanisms in case of SWAG (cf. Figure 9 and Figure 8), especially in the reservoir top zones close to the injection wells. This is a result of complex processes of CO_2 migration caused by simultaneous gravity and pressure gradient effects.

Detailed results concerning the amount of produced and injected fluids for each case of the models with reduced permeability is shown in Table 2.

Table 2. Basic results for reduced permeability models, k_h = 2.14 mD

Case	Recovery method	Production well	N_p [million SCm^3]	G_p [billion SCm^3]	W_p [million SCm^3]	G_{inj} [billion SCm^3]	W_{inj} [million SCm^3]	Recovery coefficient [%]
Base A'	Primary	vertical	0.47	0.10	0.10	0.00	0.00	9.07
Base B'		horizontal	1.12	0.27	0.28	0.00	0.00	21.53
Base C'		bilateral	1.14	0.28	0.19	0.00	0.00	21.94
I A'	Water injection	vertical	0.55	0.09	0.10	0.00	0.80	10.48
I B'		horizontal	1.92	0.57	0.90	0.00	3.36	36.74
I C'		bilateral	1.93	0.59	0.60	0.00	3.11	37.09
II A'	WAG	vertical	0.57	0.10	0.11	0.34	0.16	11.02
II B'		horizontal	4.04	1.16	2.90	1.09	6.12	77.51
II C'		bilateral	3.92	1.22	2.70	1.09	5.83	75.06
III A'	SWAG (water through the upper section, CO_2 through the lower section)	vertical	0.57	0.10	0.11	0.39	0.06	10.96
III B'		horizontal	3.57	1.97	1.36	2.17	3.02	68.40
III C'		bilateral	3.49	1.82	1.14	2.17	2.21	66.92

Summary and conclusions

1. The application of WAG/SWAG methods of EOR with the use of water and CO_2 causes a clear (even 2-fold) increase of oil recovery compared to the secondary method of waterflooding for the 5-point scheme of injection/production process, with the use of various production wells (vertical, standard and bilateral horizontal) for both standard (approx. 20 mD) and reduced (approx. 2 mD) permeabilities of the reservoir.
2. Relative efficiency of these methods compared to the method of waterflooding increases along with the decreasing permeability of the reservoir from 50% to 100% for standard to reduced permeability of the reservoir.
3. Comparison of the results of WAG/SWAG methods for various production wells (vertical, standard and bilateral horizontal) indicates the vertical well - for higher permeabilities, and the standard horizontal one – for lower permeabilities as the most favorable type of a production well. The use of a bilateral horizontal well does not lead to the increase of oil recovery.
4. SWAG method shows an increased efficiency compared to WAG method for reservoirs with standard permeability. In case of reduced permeabilities the reverse relation occurs.

The study does not include the effects of permeability hysteresis and solubility of CO_2 in water which will be the subject of a continuation of this work.

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