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CONDENSATE BANKING EFFECT ON PRODUCTIVITY IN THE WET GAS RESERVOIR AND FINDING AN OPTIMUM METHOD TO MITIGATE THIS EFFECT– CASE STUDY

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Abstract

Wet gas reservoirs show a complex behavior when they are produced below dew point pressure, according to appearance of a condensate banking phenomena and presence of a two-phase fluid in the reservoir. There is a pressure drop near the wellbore during producing gas from the reservoir to the surface. Due to excessive pressure drops, a condensate drops out from gas and flows with gas towards the wells because of compositional changes in PVT phase behavior. These all make a productivity of reservoir worse and reduce an overall recovery factor.
In this study, a wet gas reservoir simulation has been conducted to provide more accurate model of the flow of gas in to the wells by generalizing pseudo-pressure method. Also this study presents how gas recycling method could increase the condensate production and finally by a sensitivity analyses the best time period of gas injection would be introduced for the under discussion reservoir.

Keywords: Wet Gas; Condensate banking; Productivity; Simulation; Phase behavior.

1. Introduction

Productivity calculation in wet gas and gas condensate reservoir can be so difficult due to some phenomena accruing around the well which is named as condensate banking. There are different methods to model this phenomenon and considering the effect of it on reservoir production. For this purpose single well calculation and local grid refinement (LGR) around the production wells can be useful. Also using different inflow equation such as pseudo pressure equation in numerical simulation model is the other choice [1-2].

There is an option to use one of three special inflow equations to provide a more accurate model of the flow of gas into the well: the Russell Goodrich equation, the dry gas pseudo pressure equation and the generalized pseudo-pressure method. These are all methods of taking into account the pressure-dependence of $\lambda g,j$ between the grid block pressure and the well bore pressure. The generalized pseudo-pressure equation alters both the gas and oil mobilities, and takes account also of the effects of condensate dropout.

The generalized pseudo-pressure method is intended for use by gas condensate producers. It provides a means of taking account of condensate dropout, as well as compressibility, in the calculation of the mobility integral. It is based on the method described by Whitson and Fevang [3-4].

In numerical simulation, during solving the equations, at the beginning of each time step the integral of the total oil and gas mobility is evaluated between the grid block pressure and the well bore pressure at the connection. This is compared with the total oil and gas mobility at grid block conditions multiplied by the drawdown, and the ratio of the two quantities is stored as a "blocking factor" for each grid block connection in the well.

$$B = \frac{\int_{(P_w+H_{wj})}^{P_j} (M_g + M_o) dP}{\left(M_{g,j} + M_{o,j}\right)\left(P_j - \left(P_w + H_{wj}\right)\right)}$$

The integrand is fundamentally a function of two independent variables: the pressure and the gas saturation Sg. However Sg, is eliminated as an independent variable, making it a function of P at pressures below the dew point by requiring that the local total mobility ratio should be the same as the total mobility ratio at grid block conditions.

$$\frac{M_o}{M_g} = \frac{M_{o,j}}{M_{g,j}}$$

This requirement assumes that within the grid block the flows are in steady state and there is no zone of immobile dropped-out oil [2].

The integral in the first equation is evaluated by applying the trapezium rule to a set of pressure values between the grid block and connection pressures. The modeler can control the distribution of these pressure values, and hence the accuracy of the integration. At each pressure value below the dew point, the gas saturation is determined by solving second equation using Newton's method. The blocking factor is then used to multiply both the oil and gas mobilities in the inflow performance relationship. Note that the free oil mobility is modified by this treatment, whereas the Russell Goodrich and dry gas pseudo-pressure treatments leave this unchanged.

In this study, a wet gas reservoir numerical simulation is considered to make a flowing model of gas in to the wells by generalizing pseudo-pressure method. The simulation model is advanced to future for production forecast and finally a with a sensitivity analyses, an optimum method to mitigate the condensate blockage Effect, would be found [5].

The re-injection of the produced gas back into the reservoir is called gas recycling. Gas cycling is an applicable method which has been implemented in gas condensate reservoirs for many years to reduce the condensate drop-out in the reservoir [6-7].

2. Methods and procedures

In this study, a wet gas reservoir simulation has been conducted to provide more accurate model of the flow of gas in to the wells by generalizing pseudo-pressure method. Preventing from the pressure depletion in the reservoir is a good method to avoid condensate dropout. One of the methods which can compensate the loss of condensate drop out in the wet gas reservoir would be gas recycling. Historically, condensate liquids have been significantly more valuable than the gas, and this is still true in a few places far from a gas market or transport system. The price differential made gas cycling a common practice. Injecting dry gas into a formation to keep reservoir pressure above the dew point slowly displaces valuable heavy ends that are still in solution in the reservoir gas.

Under discussion reservoir in this paper is an Iranian wet gas reservoir. Constructed coarse model has dimensions of 73×97×26 (184106 grid cells) in x, y, and z direction respectively. Areal grid size is 100×100 meters and vertical grid size varies from 5 to 50 meters with average size of 19 meter. Average porosity and permeability of this reservoir is 2.6% and 1.3 mD respectively.

The average condensate gas ratio of the reservoir fluid is 30 stb/MMscf however reservoir pressure and dew point pressure are 5300 and 4400 psi respectively.

After defining and importing all required parameters, the model was successfully initialized using Eclipse 100 black oil simulation package and history matching is done. Base case scenario in production forecast of this reservoir is production under natural depletion to produce 500 MMscf/day gas. Minimum wellhead pressure is taken 900 psia in terms of natural flow of base case.

Calculation of generalized pseudo pressure option can be controlled with some equation, as explained in Introduction section, in numerical simulation with ECLIPSE package. The option is activated in gas condensate runs for individual wells. The generalized pseudo-pressure equation alters both the gas and oil mobilities, and takes account also of the effects of condensate dropout.

As shown in the Figure 1 plateau time in base case considering pseudo pressure method to model condensate banking effect, is continued for 5.25 years. Afterward gas rate would be decreased in order to maintain 900 psia well head pressure constraint. Field production under this scheme will be stopped after 23.5 years with cumulative gas production of 1.97 TCF and recovery factor of 71%. The condensate banking effect is modeled correctly in simulator and only one year condensate plateau in front of 5 years gas plateau in production profile, confirm this. Figure 1 and Figure 2 shows the comparison of base case results in 2 different scenarios with and without considering condensate banking effect in the simulation model. As it is shown the plateau time of scenario without considering condensate banking would be one year more than base case, around 6.25 year. Therefore in the base case, due to excessive pressure drops, condensate drop out from gas and flow with gas towards the wells because of compositional changes in PVT phase behavior. This makes the productivity of reservoir worse and reduces an overall recovery factor with respect to case without modeling the condensate factor phenomena. Oil saturation also reservoir pressure profile in different years of 2014, 2016, 2020 and 2040 would be according to Figure 3. As it is shown by declining the pressure bellow the dew point, oil saturation would be increased in the reservoir and condensate dropped out around the well bore.

In following gas recycling method would be optimized in the base case, considering condensate banking effect, by target of increase the condensate production of reservoir by a sensitivity analyses on the gas injection time. Gas recycling is reinjection some of the produced gas in the reservoir in order to recover more condensate. For gas recycling scenario, 1 vertical well and 3 deviated wells were designed in crestal area of the structure as gas injection wells and 9 deviated wells were designed as production wells. In this case injected gas is the output of separator unit in the production platform. It is noteworthy that field gas production rate target in this scenario was set to 750 MMscf/day and field gas injection rate was set to 250 MMscf/day also Well head pressure constraint for production wells was set to 900 psi. Figure 4 and Figure 5, show the gas production rate and gas injection rate for production and injection wells respectively. As it is shown in Figure 6, the plateau time in this scenario will be continued for 4.5 years and cumulative condensate production will be about 28.7 MMstb after 25 years of gas reinjection. It shows the increase of about 5 MMstb condensate productions on the surface in gas recycling defined scenarios in comparison with natural depletion. For sensitivity analysis on time of gas injection 5 different gas recycling scenarios are defined. In the first case gas recycling is from start of production - 2014 - however in second and third scenarios this injection would be started from years 2016 and 2019 to end of prediction respectively and in fourth and fifth cases gas recycling would be from 2014 to 2021 and 2026 respectively.

At following the results of these 5 scenarios are compared with each other. In these cases field gas production rate target set to 500 MMscf/day when there is no gas recycling operation in the reservoir. Figure 7 until Figure 9 show the results of sensitivity analyses on time of gas injection.

Reservoir recovery factor and cumulative condensate production for different scenarios of gas recycling are listed in Table 1. According to this table gas recycling from start to end of production forecast – 2014 to 2040 – would have the most condensate production also most gas recovery factor by comparison to other scenarios with different time periods of gas injection. However the optimum scenario will be determined by Economic Study.

Table 1 Comparison of different gas recycling scenarios results with the natural depletion

Scenario	RF%	Cumulative condensate (MMSTB)
Natural Depletion	71.38	23.32
Gas injection from 2014 to 2040	72.1	28.68
Gas injection from 2016 to 2040	71.4	27.5
Gas injection from 2019 to 2040	70.1	25.7
Gas injection from 2014 to 2021	71.45	28.2
Gas injection from 2014 to 2026	69.4	28.5

In economic evaluation, oil price has been taken at 80 USD per barrel and sour gas price has been taken at 6 USD per MMBTU – these numbers is assumed to be fixed during the prediction period – Based on PVT results, gas caloric value is about 1000 BTU/SCF. According to the results, 2 best scenarios of gas recycling with maximum condensate production and recovery factor is; gas injection scenario from 2014 until 2040 also the case of gas injection from 2014 until 2021. By a brief and fast economic study, in the first scenario 9975 MMUSD would be the cast of extra gas injection with respect to second scenario however the revenue of extra condensate production would be only 38 MMUSD. Therefore the best time of gas recycling in this reservoir which is economically approved would be gas injection from start of prediction forecast – 2014 – until year 2021.

3. Conclusions

Generalized pseudo-pressure equation would be used as a special inflow equation to model the flow of gas between the completed grid blocks and the well completions. The simulation results by applying condensate banking effect show that the reservoir productivity would be reduced and the plateau production time without considering condensate banking would be one year more. One of the methods which can compensate the loss of condensate drop out in the wet gas reservoir is gas recycling which could be optimized in time and volume of gas injection.

Figures:

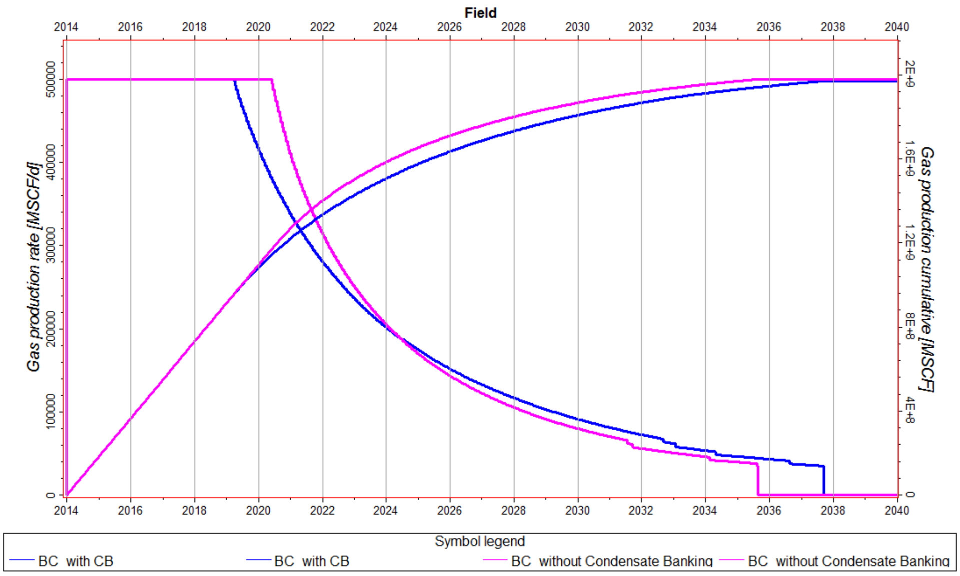

Figure 1 Comparison of field gas production rate and cumulative gas production in Base Case with and without considering condensate banking effect

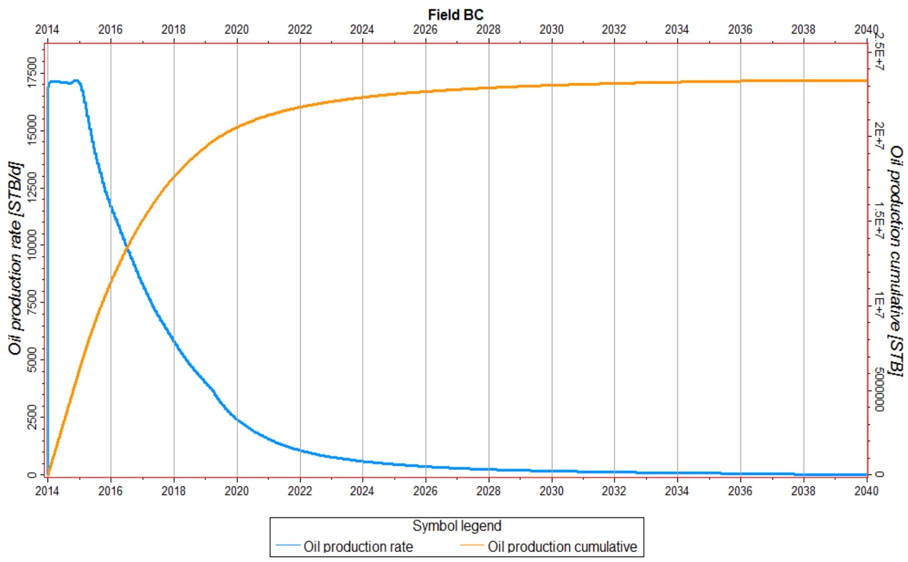

Figure 2 Condensate production rate and cumulative condensate in Base Case

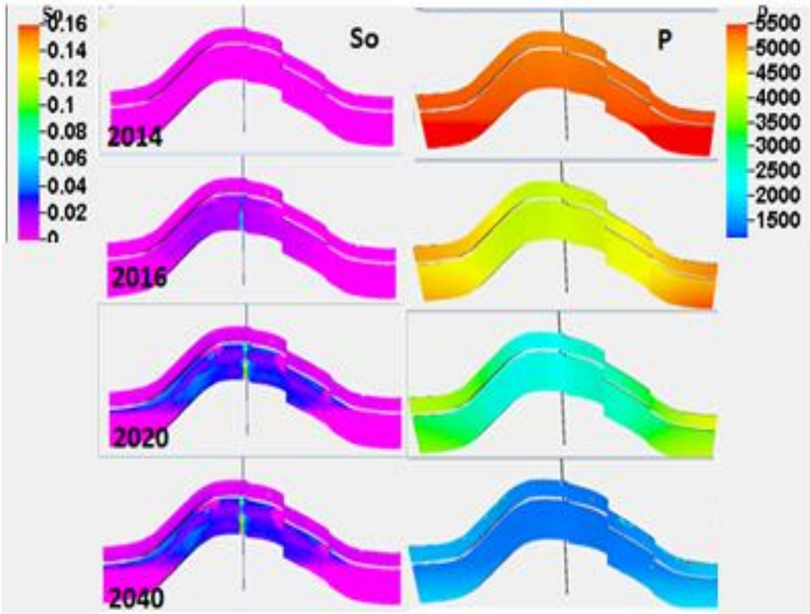

Figure 3 Oil saturation and pressure profile in a reservoir cross section – with one well in crest - in different years of production forecast

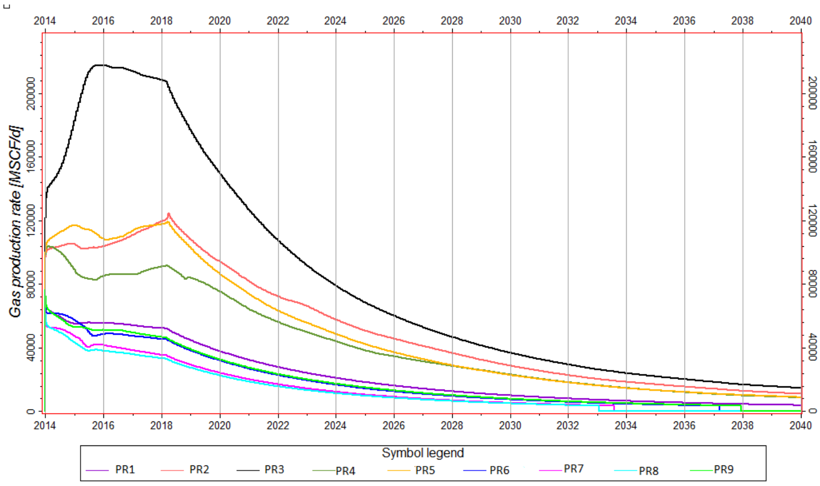

Figure 4 Gas production rate for different production wells in gas recycling scenario

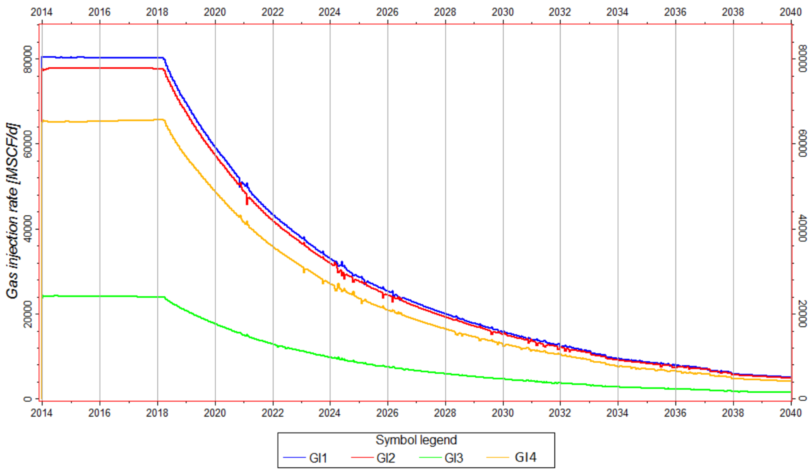

Figure 5 Gas injection rate for each of 4 injection wells in gas recycling scenario

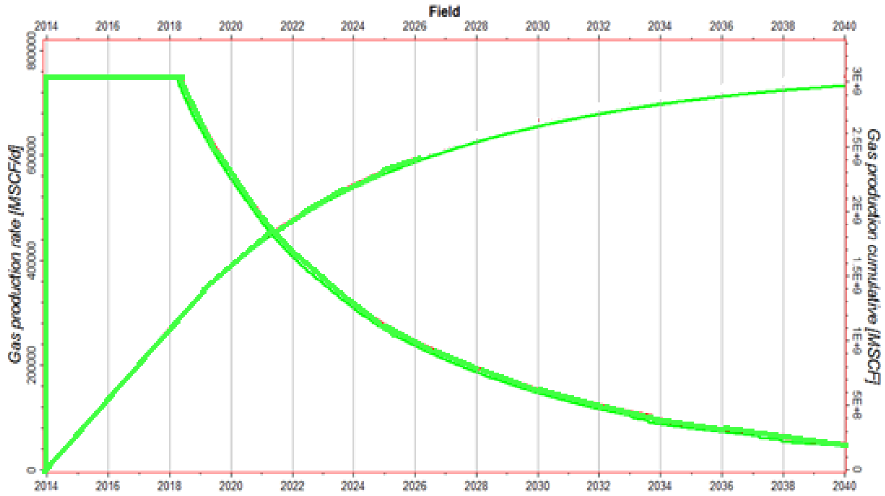

Figure 6 gas production rate and cumulative gas production for gas recycling scenario

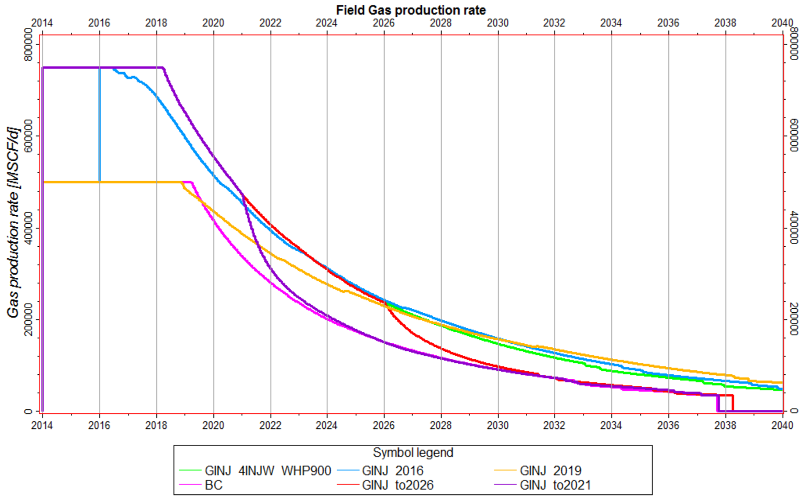

Figure 7 Gas production rate for 5 gas recycling scenarios with different time period of gas injection

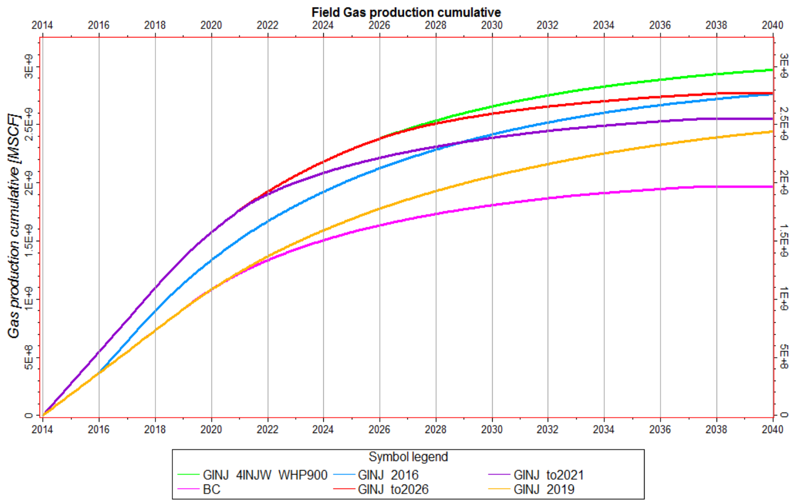

Figure 8 Cumulative gas production for 5 gas recycling scenarios with different time period of gas injection

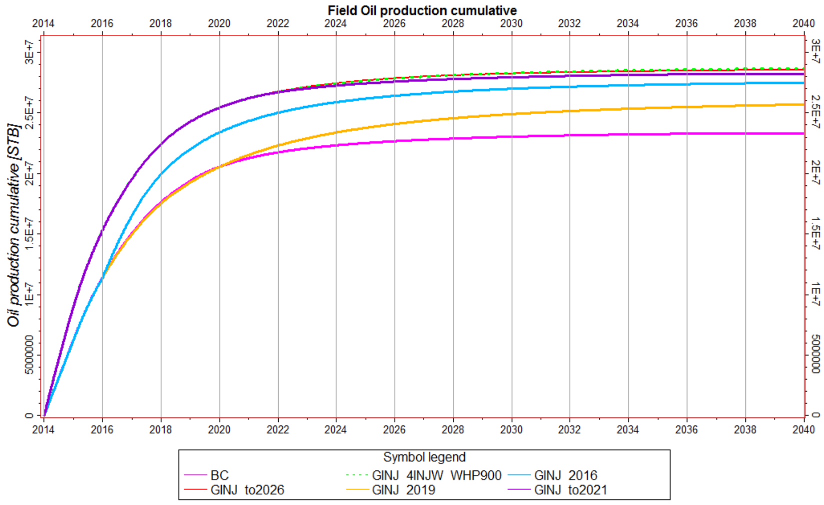

Figure 9 Cumulative condensate production for 5 gas recycling scenarios with different time period of gas injection

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