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An Overview of Methods to Mitigate Condensate Banking in Retrograde Gas Reservoirs

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Abstract

Condensate blockage is one of the major problems that have been addressed in the industry for many decades. When the reservoir fluid pressure drops below the dew point pressure during the production process, the liquid drops out of the gas phase and forms condensate in the formation. There are two scenarios that can result in a pressure drop. The first one is the pressure drop due to the flow of the reservoir fluid. The reservoir fluid flows from a high pressure of the reservoir to a lower pressure of the separators at the surface. The second scenario is the drop in reservoir pressure due to pressure depletion. During the production of gas and condensate, the reservoir pressure will decrease with time and when it drops below the dew point pressure, condensate forms everywhere inside the reservoir.

The condensate dramatically reduces the gas permeability. Hence, it decreases the gas productivity. Several methods have been suggested to solve this problem such as gas injection, CO_2 Huff-n-Puff, wettability alteration, interfacial tension reduction, hydraulic fracturing, and nonconventional wells. Some of these methods have been implemented in the field and showed positive results, but each method has its own advantages and disadvantages that need to be studied further in order to improve its efficiency. This paper will give a general review of all these methods and their effectiveness in mitigating condensate banking. The decision of using a proper treatment of condensate banking can then be made based on different scenarios that are described in this paper.

Key words: Mitigate condensate banking; Retrograde gas reservoirs; CO_2 Huff-n-Puff

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INTRODUCTION

When the reservoir fluid pressure drops below the dew point pressure, liquid drops out of the gas phase and forms condensate inside the formation. Hosein et al. describe this phenomenon as well as the equations of states that can predict gas condensation[1], and Moradi et al. have discussed some of the dew point and bubble point pressure empirical correlations[2]. This condensate accumulation, known as condensate banking or condensate blockage, causes a reduction in the relative permeability of gas; hence the productivity dramatically decreases. For example, the productivity of the Cal Canal field in California significantly decreased due to the dual effect of condensate banking and high water saturation[3]. The recovery of the Cal Canal Field was only 10% of the original gas-in-place. Another example is the Arun field in Indonesia where the well productivity declined by more than a factor of two due to the effect of condensate blockage [4]. Figure 1 shows the rapid decrease of both the gas and condensate productivity of the Arun field from 1997 to 2001 due to the accumulation of condensate in the reservoir. Condensate contains heavy ends which are valuable in terms of economic factor. Therefore, finding a feasible solution to increase the condensate and gas recovery from gas reservoirs is essential.

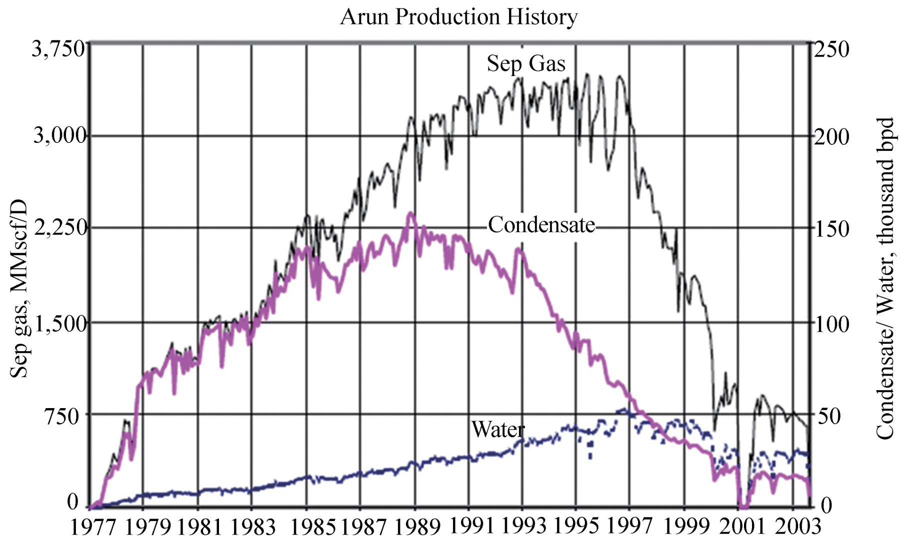

Figure 1
Arun Separator Gas, Condensate and Water Production Rates[5]

There are two scenarios that can result in a pressure drop. The first one is the pressure drop due to the flow of the reservoir fluid. The reservoir fluid flows from a high pressure of the reservoir to a lower pressure of the separators at the surface. During the production path, the pressure of the reservoir fluid at some certain locations may be lower than the dew point pressure, and the condensate accumulates at those locations. This scenario often happens near the wellbore region. A number of research studies have been conducted to examine this case, and they showed a transition from single phase to multiple phases near the wellbore due to condensate formation. According to Al-Yami et al., when the condensate forms near the wellbore, it creates three different mobility regions in the reservoir as shown in Figure 2[6]. In region 3, where the fluid pressure is still above the dew point pressure, there is only a single gas phase present. In regions 1 and 2, the fluid pressure is lower than the dew point pressure, so there are two phases present: gas and condensate. However, the difference between these two regions is the mobilization of condensate. In region 2, the condensate is immobile because the condensate saturation is below the critical point. On the other hand, in region 1, the condensate is mobile and flows together with the gas towards the wellbore because the condensate saturation is above critical saturation. These two regions are the regions of the condensate banking, so it is important to study the behavior of the fluids in these two regions to be able to mitigate condensate banking effects.

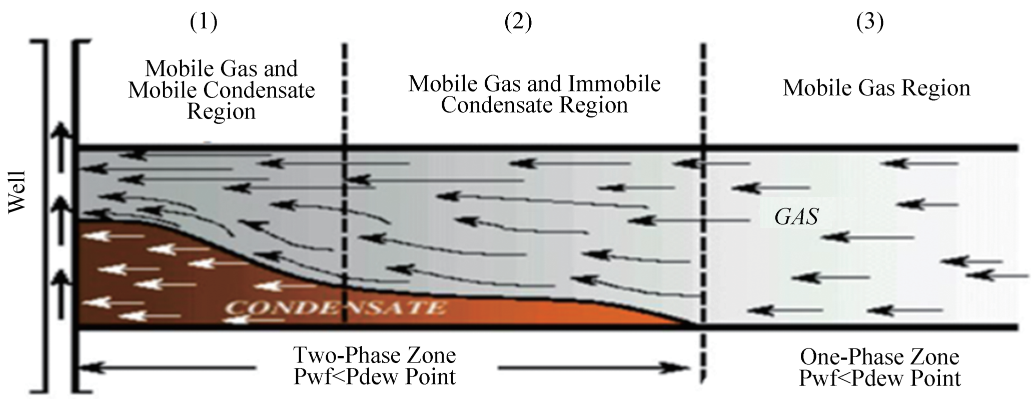

Figure 2
Condensate Saturation Below the Dew Point Pressure Flow Behavior in the Three Known Regions[6]

The second scenario is the drop in reservoir pressure due to pressure depletion. During the production of gas and condensate, the reservoir pressure will decrease with time. If the reservoir pressure drops below the dew point pressure, condensate forms everywhere inside the reservoir. However, it takes a long time before the initial reservoir pressure drops down to dew point pressure.

Several methods have been suggested to mitigate the effects of condensate banking. They can be grouped into three different approaches. The first approach is to keep the reservoir pressure above the dew point pressure by gas cycling or CO_2 Huff-n-Puff. The second one is to mobilize the condensate near the wellbore region in order to make it flow with gas towards the wellbore. To achieve this approach, either wettability alteration or reduced interfacial tension methods can be used. The last approach is to reduce the drawdown pressure in order to delay the time of reaching the dew point pressure through hydraulic fracturing or horizontal wells.

1. GAS INJECTION

Historically, dry gas injection has been one of the most common methods to prevent condensate blockage. Injecting dry gas into the reservoir will help maintain the reservoir pressure above the dew point pressure as well as displace the valuable condensate in the reservoir[7]. Also, if condensate blockage already existed inside the reservoir, gas injection re-vaporizes the condensate[8]. Even though gas cycling is very effective in mitigating condensate banking, the increase in gas consumption for higher value applications has motivated scientists to find an alternative for the injected supply. Farzad et al. studied reservoir production strategies in miscible and immiscible gas injection projects[9]. Rostami et al. have studied the feasibility of miscible gas injection in a carbonate reservoirs[10].

Carbon dioxide, pure methane, and nitrogen are considered alternatives for dry gas. Amini et al. proved in their study that carbon dioxide injection increases condensate recovery significantly due to the fact that it removes the condensate blockage and prevents the condensate accumulation for a certain time after the injection is stopped[11]. Nitrogen is a good consideration since it is a cheap, non-corrosive, and clean gas. However, there are some issues related to the use of nitrogen. Even though nitrogen injection increases condensate recovery, it is not as effective as carbon dioxide, methane injection, and gas cycling. Siregar et al. did an experiment to point out that methane evaporates the liquid with less amount of injection (55% mole fraction) than nitrogen (98%)[12]. Their study also shows that injected nitrogen can mix with gas condensate in the reservoir, and the dew point pressure of the mixture is higher than the initial dew point pressure of the reservoir. As a result, condensate drop-out increases in the reservoir. According to the study of Amini et al., carbon dioxide is very effective in gas recovery[11]. The performance is almost the same as natural gas. At some lower pressure, carbon dioxide injection has an even higher gas recovery rate compared to natural gas injection. However, carbon dioxide is less effective in recovering condensate compared to natural gas. Therefore, further studies of carbon dioxide injection are needed to improve the efficiency of condensate recovery.

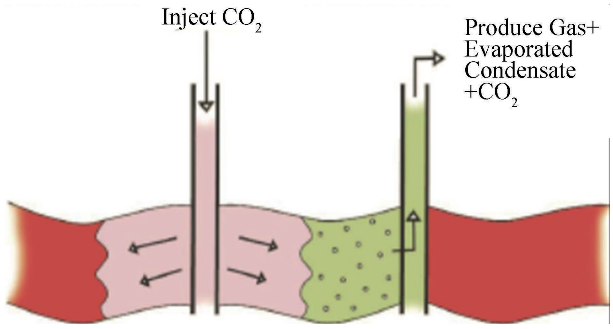

Figure 3
CO_2 Enhanced Gas Recovery Description[13]

The advantage of gas injection is that it can mitigate the problem of condensate forming deep inside the reservoir. It can be used to prevent condensate from forming inside the reservoir by maintaining the reservoir pressure above the dew point pressure, or it can solve condensate blockage problems where condensate has already formed inside the reservoir. It will re-vaporize the condensate and push the gas toward the producer. However, the weakness of this method is that a large amount of gas injection is needed.

2. CO_2 HUFF-N-PUFF

The process of this method is similar to the use of carbon dioxide injection in Enhanced Gas Recovery where CO_2 is used to displace natural gas and condensate in order to increase the recovery. However, in CO_2 Huff-n-Puff operations, CO_2 is injected directly into the production well and then the well is shut-in to let the CO_2 interact with the reservoir fluid and condensate for a certain period of time[13]. The gas is then produced from the same well as illustrated in Figure 4.

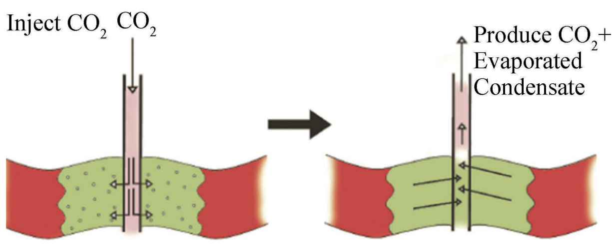

Figure 4
CO_2 Huff-n-Puff Process Description (Revised From Odi, 2012)

A study by Odi showed that CO_2 forms a mixture with the reservoir fluid and results in a lower dew point pressure in the reservoir[13]. As a result, condensate re-evaporates and is produced along with the CO_2 flowing back to the wellbore. The study has showed that as the concentration of CO_2 increases, the dew point pressure is reduced as shown in Figure 5. This method is effective when initiated before maximum liquid dropout is reached[14].

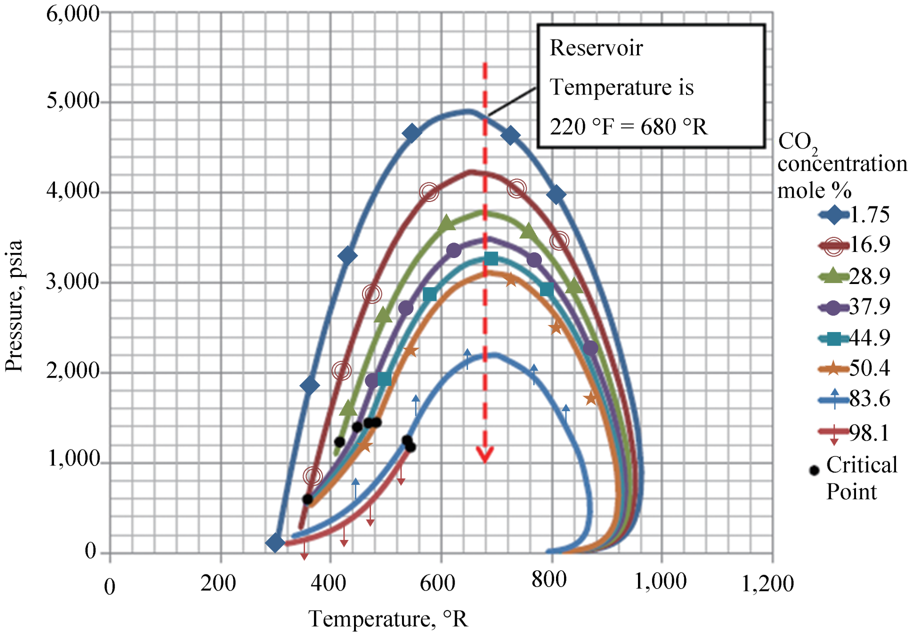

Figure 5
Phase Envelope of Typical Wet Gas Composition as Function of CO_2 Concentration[13]

However, this method is a short-term stimulation because after the production begins for a certain period, the condensate blockage returns due the higher dew point pressure of the current gas mixture. The method is only effective when condensate forms near the wellbore region. If the condensate forms deep inside the reservoir, this method is not as effective because its effective radius is very short. An advantage of this method is that a smaller amount of injected CO_2 is used compared to a full CO_2 injection.

3. WETTABILITY ALTERATION

When condensate blockage forms near the wellbore, the condensate in this region is immobile. If the condensate is mobilized, it will flow with the gas phase in the reservoir towards the wellbore; hence, the gas relative permeability increases and the productivity is improved. In order to achieve this result, a surfactant can be used to change the wettability of the reservoir from liquid wet to intermediate or gas wet. This method is known as wettability alteration.

Li and Firoozabidi were successful in using chemical solutions FC759 and FC722 to change the wettability of a rock sample[15]. A later study of Fahes et al. showed that these chemical solutions are not effective at a high temperature in the reservoir[16]. Also, these chemical solutions are expensive, so it is not a feasible method in the industry. Therefore, Liu et al. studied various solvents to find one that is economical and stable at a high temperate of the reservoir[17]. They found WA12 as a potential solution for condensate blockage. It is thermally stable at 170 °C and 20 times cheaper than the chemical solutions that Li and Firoozabidi used. At the same time, another study conducted by Alzate et al. shows that Alcohol 21-NE-06 and inhibited diesel are effective in removing condensate banking and increasing the gas effective permeability[18].

4. INTERFACIAL TENSION REDUCTION

Another method to mobilize condensate blockage is to reduce capillary pressure which causes condensate to be trapped inside the reservoir. According to Al-Anazi et al., capillary pressure can be reduced by decreasing the interfacial tension[19]. Solvents like alcohol can be used to reduce the interfacial tension and remove condensate through a multi-contact miscible displacement[20]. Several cases of successful alcohol-based treatments in the field have been reported to be successful. After the first four months of methanol treatment, the productivity of Hatter's Pond field increased by a factor 2[20]. In the Cupiagua field, inhibited diesel and Alcohol blends were the main stimulation treatments to mitigate condensate banking for several years. However, this method can only temporarily mitigate the condensate, and after a short period of the treatment, condensate starts accumulating again inside the reservoir[21].

5. HYDRAULIC FRACTURING

According to Ignatyev et al., hydraulic fracturing is very effective in mitigating the effect of condensate blockage because it increases the well contact area with the reservoir and decreases reservoir drawdown [22]. However, Fan et al. pointed out that this method does not eliminate the accumulation of condensate in areas where the pressure in the formation is below dew point. It only delays the time of reaching the dew point pressure but does not completely prevent condensate blockage[7]. Also, Fahes et al. indicated that the clean-up of water accumulation from the formation after fracturing is crucial to increase the productivity[16]. However, the clean-up process may take a long time due to low permeability and the wettability characteristics. Moreover, hydraulic fracturing method is expensive, so sometimes it is not profitable to use it to mitigate the condensate banking.

6. HORIZONTAL WELLS

Miller et al. show in their study that the drawdown pressure for a horizontal well is much smaller than the drawdown pressure for a vertical well[23]. Therefore, it will take a longer time for the bottom-hole pressure in a horizontal well to reach dew point pressure compared to a vertical well. Also, the study indicates that a horizontal well reduces condensate blockage near the wellbore because the productivity index in the horizontal well almost remains the same after the dew point pressure is reached. Even though using a horizontal well has been proven effective for mitigating condensate blockage, it does not prevent condensate from forming near the wellbore. Also, a horizontal well is more expensive than a comparable vertical well, so it is essential to make a comparison between the benefit and cost.

CONCLUSION

Although several methods have been suggested to mitigate the effects of condensate banking such as gas injection, CO_2 Huff-n-Puff, wettability alteration, interfacial tension reduction, hydraulic fracturing, and horizontal wells, many of them have their disadvantages when it comes to application in the field. For gas injection, natural gas is usually used and shows the best results compared to other gases such as methane, carbon dioxide, or nitrogen. However, a large amount of natural gas is needed to use in a full large scale of injection. The CO_2 Huff-n-Puff method is a short-life stimulation method because after a short period of the treatment, condensate blockage returns due to the higher dew point pressure of the current gas mixture. Wettability alteration and interfacial tension reduction showed a promising result in mitigating condensate banking, but the treatments are only effective when the condensate is near the well bore, and they cannot remove condensate deep inside the reservoir. Hydraulic fracturing and horizontal wells are not economical and only delay the time of reaching the dew point pressure but do not completely prevent condensate blockage.

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