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Effect of Injected Gas Type on Condensate Recovery of Gas Reservoirs Using 3D Compositional Modeling

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Abstract

Production from gas condensate reservoirs has a big challenge which is condensate drop-out in the reservoir pores when the reservoir pressure drops below the dew point pressure. This condensate accumulation around the wellbore reduces the productivity of the wellbore. Gas recycling is a famous enhanced production methodology to maximize condensate recovery of gas reservoirs. In this study, a three-dimensional (3D) compositional model is used to study the effect of injected gas type on condensate recovery for gas reservoirs with different quality and gas with a wide range of condensate yield. Three types of gases; nitrogen (N2), carbon dioxide (CO2) and dry gases are used as injected gas. The model was produced through five wells under depletion process as base case then apply gas injection with CO2, N2 and dry gas individually. Crestal injection pattern was performed with vertical well as injector and four vertical producing wells in down dip of the reservoir. Based on the research result, for low quality reservoir, N2, CO2 or dry gas injection have higher condensate recovery than depletion case by 50% ,100% and 130% for 20, 40 and 60 STB/MMSCF condensate content gases respectively. and have nearly the same effect on condensate recovery for different gas condensate yields. While for mid and high-quality reservoirs, N2 and dry gas injection have higher condensate recovery than CO2 by 55% ,35% and 25% for 20, 40 and 60 STB/MMSCF condensate content gases respectively and depletion cases by 40% ,70% and 90% for 20, 40 and 60 STB/MMSCF. condensate content gases respectively. Also, the summary results show that the optimum injection gas type is dry gas due to it has highest condensate recovery, lower cost, operation impact and easily available for covered different reservoir quality and gas condensate yields in this study.

Introduction

Gas condensate reservoirs play an important role in the oil and gas industry. Currently, gas condensate fields represent the main hydrocarbon production in many countries to meet the industry requirements. Gas condensate reservoir is single phase at the initial condition, then condensate starts to dropout within reservoir pores when the reservoir pressure decreases below the dew-point pressure of the gas [1, 2, 3]. The condensate drop-out causes reservoir pores blockage, which reduces the gas and condensate recovery factor [4, 5, 6, 7, 8, 9, 10].

Also, gas condensate wells have a rapid loss of well productivity due to condensate drop-out when the flowing bottom hole pressure drops below the dew-point pressure. A region of high condensate saturation builds-up around the wellbore causes reduction of gas permeability and gas deliverability [11, 12, 13, 14]. Industrial experience of the gas condensate reservoirs indicates that the average gas recovery in gas condensate reservoir under depletion drive is ranged from 40-60% while the condensate is ranged from 10 to 30% [15].

To maximize the hydrocarbon recovery from gas condensate reservoirs, many secondary and tertiary recovery methods are applied. These technologies include gas and condensate displace by different type of gases as nitrogen (N2), carbon dioxide (CO2) and residue dry gases [16, 17]. The feasibility of applying such technologies depends on the amount of gas and condensate reserves, availability of injected gas, available and complexity of surface facilities, the complexity of the field geological structure, the reservoir depths, and payback period with production agreement period.

Gas injection in gas condensate reservoir aims to keep reservoir pressure above dew-point pressure, decrease the dew-point pressure of new mixture composition and vaporize the mid and heavy components dropped in the reservoir. The gas injection can improve gas and condensate recovery factor up to 65-80% for gas recovery and 40-60% for condensate recovery which is proved through experimental work or by using numerical simulation in previous studies [18, 19, 20, 21]. But these studies did not cover different reservoir quality or gases with different condensate content.

The gas and condensate recovery factors in a gas condensate reservoir under gas injection mechanism are influenced by many factors such as the difference between the reservoir pressure and the dew point pressure, the condensate content, the reservoir quality and production and injection pattern [22, 23, 24, 25, 26].

The objective of this research is to study the effect of injected gas type (N2, CO2 and dry gas) on condensate recovery with reservoir pressure above the dew-point using three-dimensional (3D) compositional simulation model [27, 28, 29, 30]. This study will be applied for gas reservoirs with different condensate contents and different reservoir quality degrees producing with vertical wells using Eclipse software.

Research Methodology

The implemented methodology to achieve the objective of this research is as follow:

1. Construct 3D static model for three reservoirs with different quality degrees using Petrel software [31, 32, 33, 34].
2. Construct pressure-volume-temperature (PVT) compositional model for three gas condensate fluid samples with condensate content; 20, 40 and 60 STB/MMSCF, respectively [35, 36, 37].
3. Initialize the 3D static model of the three reservoirs using the three gas condensate models (total number of models = 9) using Petrel software [38].
4. Run the 9 models under depletion drive (Gas production without residue gas recycling) to estimate gas and condensate ultimate recovery which will be used as base case to estimate additional gas and condensate recovery with gas recycling using Eclipse software [39, 40, 41, 42].
5. Perform models run under N2, CO2 and dry gas respectively with voidage replacement ratio equal 1 for the 9 models using vertical producing wells.
6. Perform models results analysis for each reservoir quality degree and gas PVT model, under different gas injection types. then rank the results according to condensate recovery to determine the effect of each gas type on condensate recovery then the injected gas type which yields the maximum condensate recovery.

3D Reservoir Static Model

The reservoir used for this study is faulted anticline sandstone reservoir. This reservoir is capped by shale and bounded by north east and south east huge faults. The reservoir dipping is from north east to south west. The reservoir is subdivided into 2 vertically communicated zones from depth 3500 ft to 4900 ft (SSD) with clear gas-water contact (GWC) at 4700 ft (SSD). The reservoir has five penetrating wells as shown in **Figure 1**.

3D structure model is built using 4 seismic horizons (top of upper shale, top of sand A, top of sand B and top of lower shale with 2 faults). The model dimension is 39 x 37 in X and Y dimension, respectively, with 100 m spacing and is subdivided vertically into 61 layers with total number of cells are 88023 cells. Facies model is constructed using the facies logs of the five wells then distribute porosity and permeability model to have three models with different quality degrees as follow: -

- Low reservoir quality (Average porosity = 10%, & Average Permeability = 100 md)
- Mid reservoir quality (Average porosity = 15%, & Average Permeability = 1000 md)
- High reservoir quality (Average porosity = 20%, & Average Permeability = 5000 md)

Four wells are used as producer in down dip and one well is used as injector in reservoir crest (peripheral pattern). The aquifer is weak so no aquifer model is applied. **Figure 2** shows the constructed 3D reservoir model.

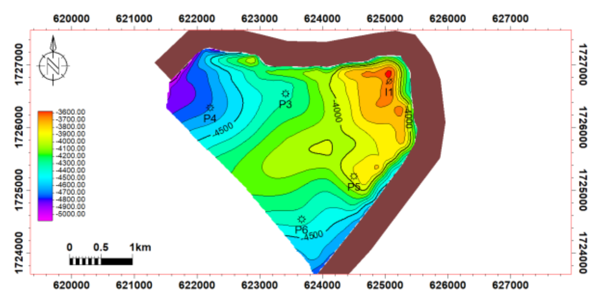

Figure 1 Reservoir Structure Contour Map with Penetrating Wells.

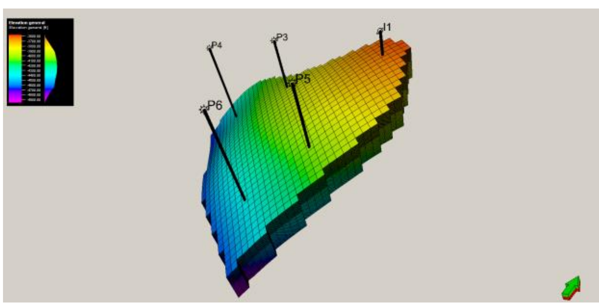

Figure 2 Reservoir 3D Model with Penetrating Wells.

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PVT Model

Three gas samples are taken from different gas condensate reservoirs with condensate yield 20, 40, 60 STB/MMSCF. Three calibrated models with equation-of-state (EoS) are constructed for the three gas samples using pressure volume temperature petroleum expert software (PVTp) [43]. The EoS model construction workflow includes:

- Select equation of state type [44, 45, 46].
- Splitting pseudo component [47, 48].
- Match dew point pressure with binary interaction coefficients.
- Match constant composition expansion (CCE), constant volume depletion (CVD) and separator tests data using different EoS parameters [49, 50].
- Match gas viscosity.
- Lump the composition into 8 compositions and rematch again if needed.
- Export PVT data as compositional model (EoS with its related parameters).

Figure 3 , **Figure 4** and

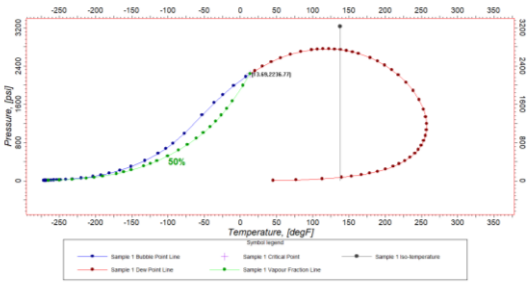

Figure 5 show the phase diagram of the three samples respectively and **Table 1** shows the lumped composition of the three calibrated gas PVT models.

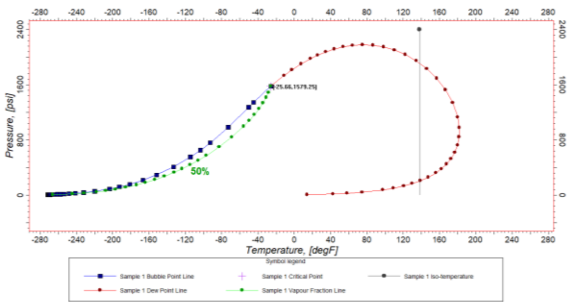

Figure 3 Phase Diagram of Gas with Condensate Yield 20 STB/MMSCF.

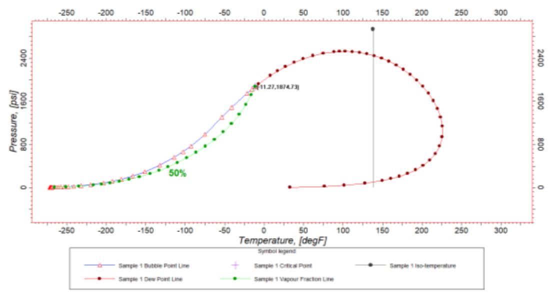

Figure 4 Phase Diagram of Gas with Condensate Yield 40 STB/MMSCF.

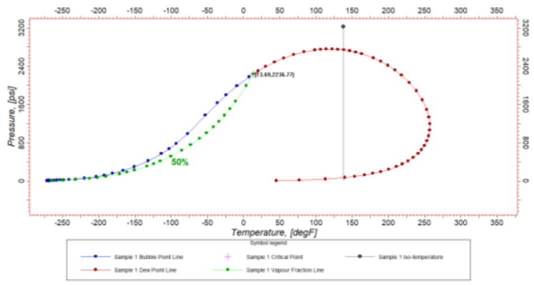

Figure 5 Phase Diagram of Gas with Condensate Yield 60 STB/MMSCF.

Table 1 Lumped Composition of The Three Calibrated Gas PVT Models.

	Gas Composition with Condensate Yield 20 STB/MMSCF	Gas Composition with Condensate Yield 40 STB/MMSCF	Gas Composition with Condensate Yield 60 STB/MMSCF
Component	More percent, %	More percent, %	More percent, %
N2	0.23	0.23	0.22
CO2	0.13	0.13	0.12
C1	80.04	78.15	76.37
C2	8.41	8.22	8.04
C3, iC4 & nC4	7.63	7.68	7.71
iC5, nC5 & C6	1.96	2.71	3.38
C7, C8 & C9	1.25	2.23	3.18
C10 & C11+	0.34	0.65	0.96
Sum	100	100	100

Model Initialization

The model initialization means that pressure and fluid saturations are defined in each grid cell at zero production and injection time. Use GWC at depth 4700 ft (SSD) and use pressure at depth 4200 ft (SSD) as datum pressure for pressure distribution in 3D. Based log data analysis and relative permeability data from offset field, SCAL data is created with Swi=11% and Pcgw=0. For PVT model, use the three compositional models separately with condensate yield 20, 40, 60 STB/MMSCF.

Error! Reference source not found. summarized the initialized compositional models' conditions, which are used for predictive runs under depletion and gas recycling cases. Firstly, perform initialization runs without production or injection for the models to check models' stability and calculate the initial gas and condensate in place.

Table 3 shows the gas and condensate initially in place for the nine models.

Table 2 Initialized Compositional Models Conditions.

	Gas Reservoir		
Items	Condensate Yield 20 stb/mmscf	Condensate Yield 40 stb/mmscf	Condensate Yield 60 stb/mmscf
Initial pressure, psi	2400	2935	3225
Datum, ft TVDss	-4200	-4200	-4200
Dewpoint Pressure, psi	1900	2435	2725
Gas water Contact (GWC), ft TVDss	-4700	-4700	-4700
Capillary pressure @GWC	0	0	0
Reservoir Temperature, F	0	0	0

Table 3 Gas and condensate initially in place for the nine models.

Model	Reservoir quality	Gas Condensate Yield, stb/mmscf	Initial Gas in place, bscf	Initial Condensate in place, mmstb
1	Low	20	439	9
2	Low	40	541	22
3	Low	60	586	35
4	Mid	20	659	13
5	Mid	40	811	32
6	Mid	60	879	53
7	High	20	834	17
8	High	40	1033	41
9	High	60	1120	67

Base Case Runs

Five wells (one crest vertical well and four down-dip vertical wells) are used to construct the depletion case (no gas injection) to be used as base case for the nine models. The production controls and constrains can be summarized as follow: -

1. Field control production is 60 MMSCFD.
2. Well maximum production is 20 MMSCFD.
3. Well constrained bottom-hole flowing pressure is 650 Psi.
4. Well economic gas and oil rate are 1 MMSCFD and 20 STBD, respectively.
5. Use two separator stages 250 psi/100 oF and 14.7 psi / 60 oF.
6. Prediction years are 40 years (2024-2064).

Figure 6, Figure 7 and F **Figure 8** show the reservoir pressure performance and cumulative condensate production results for the three gas models (20, 40, 60 STB/MMSCF condensate content) at low, mid and high-quality reservoirs, respectively, with vertical producing wells under depletion case. With production without injection; the reservoir pressure is rapidly depleted. The condensate occurs around the producers and in the reservoir pores that have pressure below the dew-point pressure. Condensate is an immobile phase and causes a sharp decline in the well productivity. The results show that as the reservoir quality increases, the cumulative condensate production increases for the same gas type (same condensate yield) because of the pressure drop and effect of condensate blockage is lower for better reservoir quality. While for the same reservoir quality, as the gas condensate content increases, the cumulative condensate production increases due to higher condensate content.

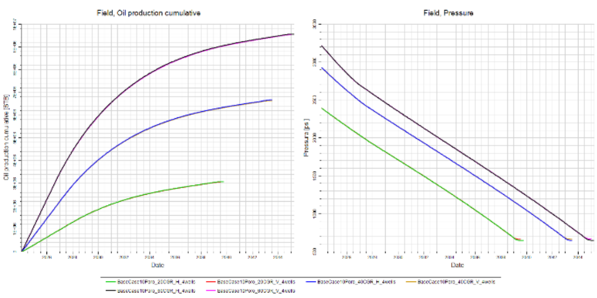

Figure 6 Cumulative Condensate Production and Reservoir Pressure under depletion Case for Low quality Reservoir.

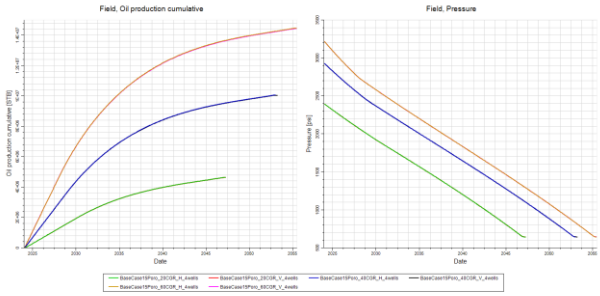

Figure 7 Cumulative Condensate Production and Reservoir Pressure under depletion Case for Mid quality Reservoir.

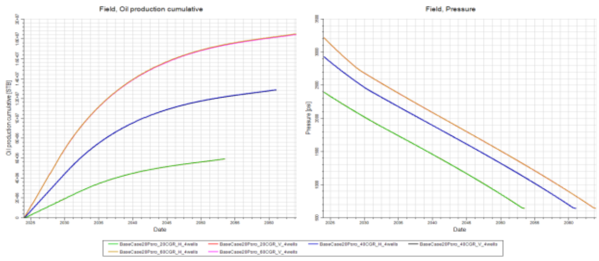

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Figure 8 Cumulative Condensate Production and Reservoir Pressure under depletion Case for High quality Reservoir.

Gas Injection Sensitivity Cases Runs

One crest well as injector and four down-dip wells as producers are used to construct the gas injection cases with different type f injected gas (N_2, CO_2 and dry gas) . Each type of injected gas is applied with the each reservoir and gas type to evaluate its effect on condensate recovery. The production controls and constrains can be summarized as follow: -

1. Field control production is 60 MMSCFD.
2. Well maximum production is 15 MMSCFD.
3. Well constrained bottom-hole flowing pressure is 650 psi.
4. Well economic gas and oil rate are 1 MMSCFD and 20 stbd respectively.
5. Reservoir voidage replacement ratio is 1
6. Use two separator stages 250 psi/100 °F and 14.7 psi / 60 °F.
7. Well constrained bottom-hole injection pressure is 4000 psi.
8. Prediction years are 40 years (2024-2064).

With gas injection, the cumulative condensate production is higher than the depletion case as shown in **Figure 9** due to:

- The reservoir pressure is maintained with gas injection, or the pressure depletion rate decreased which decreases the condensate dropout.
- The new composition of the reservoir fluid after gas injection has a lower dew point pressure.
- Vaporizing or displace some of the heavy components that dropped out during gas production near the well bore.

The results show that with gas injection as the reservoir quality increases, the condensate production recovery increases for the same gas type because of lower pressure drop near the well bore and lower effect of condensate blockage for better quality as shown in **Figure 10**. While for the same reservoir quality, as the gas condensate content increases, the cumulative condensate production is higher due to higher condensate content as shown in **Figure 11**.

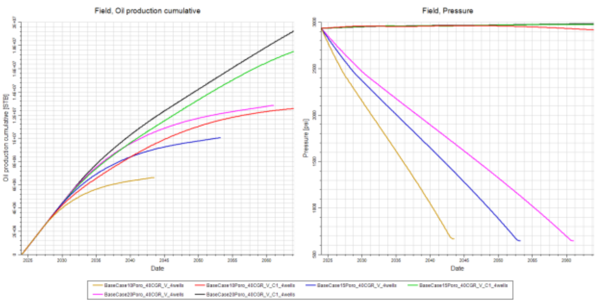

Figure 9 Comparison of Cumulative Condensate Production and Reservoir Pressure Results under Depletion and Full Dry Gas Injection for Gas 40 STB/MMSCF Condensate Yield with Different Reservoirs Quality.

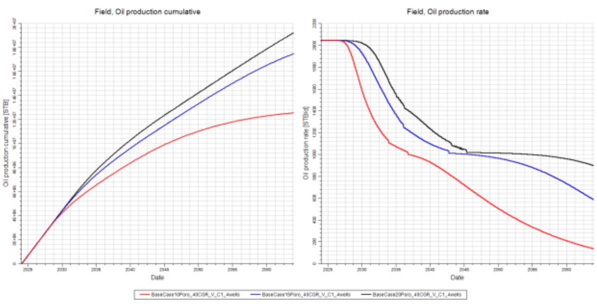

Figure 10 Cumulative Condensate Production and Reservoir Pressure under Full Dry Gas Injection for Gas 40 STB/MMSCF Condensate Yield with Different Reservoirs Quality.

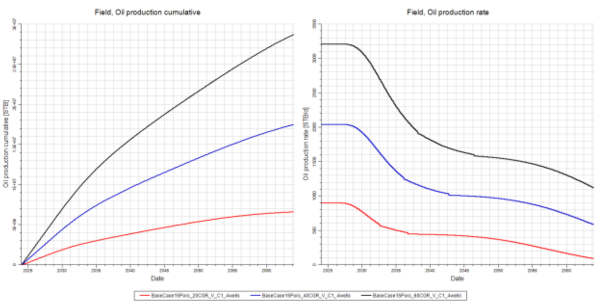

Figure 11 Cumulative Condensate Production and Reservoir Pressure under Full Dry Gas Injection for Mid quality Reservoir with Different Gas Quality.

Results and Discussion

CO_2, N_2 and dry gas are used to evaluate the effect of gas injection type for each model of the concerned 9 models with vertical producing wells on condensate recovery. The results show that the cumulative production of condensate during recycling is affected by two opposite effects. The first is the effect of pressure maintaining and vaporization of dropped condensate with dry gas recycling which increase condensate production with increasing the injection ratio. The second is the effect of dry gas break through to the producers which decreases the condensate recovery as the injection ratio increases the results summary for low, mid and quality reservoirs are summarized below in the following: -

Low Quality Gas Reservoir "Optimum Gas Type"

Figure 12 shows the results of cumulative condensate versus gas condensate yield with depletion, CO_2, N_2 and dry gas injection in low quality gas reservoir. The condensate recovery increase with gas injection (CO_2, N_2 or dry gas) more than the case of no gas injection for all gas condensate content types. CO_2, N_2 and dry gas injection have nearly the same effect on condensate recovery for low quality reservoir.

As the gas condensate yield increase, the amount of recovered condensate increase comparing to the depletion case. For gas with 20 STB/MMSCF condensate yield, the recovered condensate increased by 40% more than depletion case. For gas with 20, 40 and 60 STB/MMSCF condensate yield, the recovered condensate due to dry gas injection increased by 49%, 98% and 128% respectively more than depletion case.

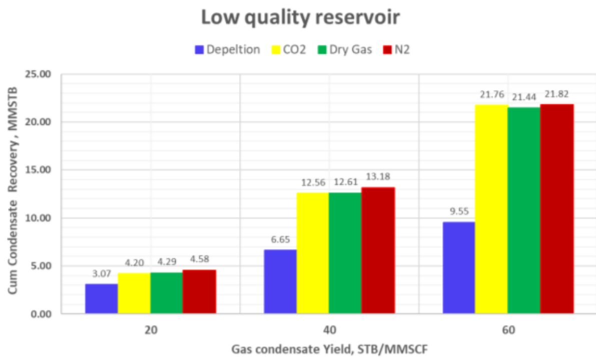

Figure 12 Cumulative Condensate versus Gas Condensate Yield with Depletion, CO_2, N_2 and Dry Gas Injection for Low Quality Reservoir.

Mid Quality Gas Reservoir "Optimum Gas Type"

The results of mid quality gas reservoirs indicate that N_2 and dry gas injection achieve more condensate than CO_2 and depletion cases respectively as shown in **Figure 13**. N_2 and dry gas have molecular weight (14, 12 gram-mole respectively) lower than initial reservoir gas composition (22 to 24 gram-mole) so in case of N_2 and dry gas injection the injected gas moves upward and displace reservoir gas downward in the direction of down dip producers and achieve better displacement. While CO_2 has molecular weight (44 gram-mole) higher than initial reservoir gas composition so the injected CO_2 move downward and displace reservoir gas upward in the direction of down dip producers and causing early break through faster than N_2 and dry gas injection case. Also, it is shown in **Figure 13** that the effect of injected gas to recover more condensate increase as the gas condensate yield increase more than depletion case for all type of injected gas especially for reservoir gas with 40 STB/MMSCF and 60

STB/MMSCF condensate yield. So in case of mid quality gas reservoir, the optimum injection gas type is dry gas due to it has lower cost and easily available more than N2. The added recovered condensate with dry gas injection is higher than depletion case by 45% for gas with 20 condensate yield, 77% for gas with 40 condensate yield and 100% for gas with 60 STB/MMSCF condensate yield.

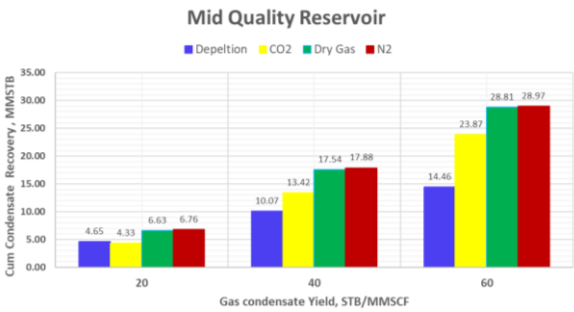

Figure 13 Cumulative Condensate versus Gas Condensate Yield with Depletion, CO2, N2 and Dry Gas Injection for Mid Quality Reservoir.

High Quality Gas Reservoir "Optimum Gas Type"

For high quality gas reservoir, it has the same results trend as mid quality gas reservoir for the same reason. As shown in **Figure 14**, CO2 injection has lower cumulative produced condensate than N2 and dry gas injection. Also, for gas with 20 STB/MMSCF the CO2 injection give lower cumulative produced condensate than depletion (no injection) case. Based on that the optimum feasible injection type in case of high quality gas reservoir is dry gas injection. The dry gas injection will add higher cumulative condensate than depletion case by 43% for gas with 20 condensate yield , 53% for gas with 40 condensate yield and 71% for gas with 60 STB/MMSCF condensate yield.

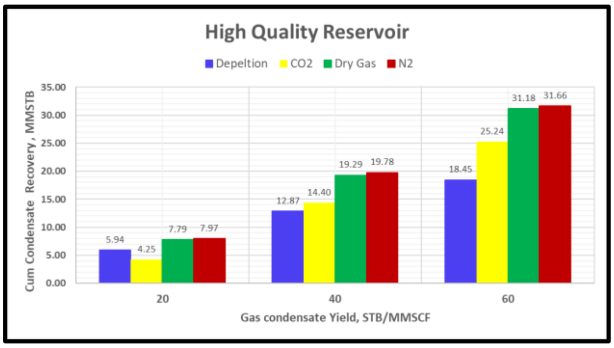

Figure 14 Cumulative Condensate versus Gas Condensate Yield with Depletion, CO2, N2 and Dry Gas Injection for High Quality Reservoir.

Conclusions

Gas condensate reservoirs have significant contribution in oil and gas production. Gas condensate reservoir have two phase flow of gas and condensate within the reservoir pores below the dew-point pressure causing condensate dropout and blockage which reduce gas production. Dry gas recycling is one of the most economic and effective solution to solve this problem. This study utilized 3D Compositional model to study the effect of injected gas type (N2, CO2 and dry gas) on condensate recovery. The model used vertical producing wells and apply gas injection at reservoir pressure above the dew-point pressure of reservoir gas. Based on the modeling study results, the following points are concluded:

- Low quality reservoir, N2, CO2 or dry gas injection have higher condensate recovery than depletion case by 50% ,100% and 130% for 20, 40 and 60 STB/MMSCF condensate content gases respectively. and have nearly the same effect on condensate recovery for different gas condensate yields.
- Mid and high-quality reservoirs, N2 and dry gas injection have higher condensate recovery than CO2 by 55% ,35% and 25% for 20, 40 and 60 STB/MMSCF condensate content gases respectively and depletion cases by 40% ,70% and 90% for 20, 40 and 60 STB/MMSCF. condensate content gases respectively due to breakthrough of CO2 at the producers is earlier than N2 and dry gas at the producers.
- For all reservoir quality and different gas condensate yield covered in this study, the optimum injection gas type is dry gas due to it has lower cost and easily available more than N2.
- With dry gas injection the added recovered condensate over depletion case increases as the reservoir quality decrease.

These results can be used as initial guidelines to optimize the injected type before start studying the effect of gas rejection type on gas condensate field with its real properties, operation and economic conditions.

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Conflicts of interest

There are no conflicts to declare.

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