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OPTIMIZATION OF CONDENSATE RECOVERY USING GAS RECYCLING TECHNIQUE

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Abstract

Condensate production from gas condensate reservoirs have remained a key concern to the petroleum industry. Huge amount of valuable liquid is lost due to condensate drop out in the reservoir during depletion process. The accumulation of this liquid forms a condensate bank around the wellbore region.The flow of gas near the wellbore is restricted due to huge liquid dropout that is lost to the reservoir. This reduces the productivity of the wellbore. The optimization of condensate recovery can be achieved through enhanced production technique known as gas cycling. In this study, a technical approach is employed to evaluate the potentials of various production techniques using different injection rates and pressures. Model for the prediction of condensate recovery was developed by integrating experimental design, reservoir composition and fluid characterization followed by parametric study in order to determine the optimal scheme that promises highest condensate production. The model was used to ascertain the effects of the reservoir and production parameters on condensate recovery from condensate reservoirs by investigating a wide range of production approaches in projects where gas cycling technique was employed. From this research, optimal injection rate and the effective injection pressure gave the best production strategy. A five-spot injection pattern with fine grids near the producer and injector was employed in this study. At any fixed injection pressure, the higher the injection rate, the more condensate was recovered. From the results of the simulation, condensate recovery increased drastically from in all injection scenarios studied.

Key words: Condensate; gas cycling; recovery; production; optimization.

1. Introduction

Gas condensates are single-phase gaseous hydrocarbon in the reservoir with considerable liquid hydrocarbon content dissolved in them at a particular reservoir condition [1]. Isothermal production of the reservoir results in an attendant pressure decline which if not controlled in a condensate system, will drop beyond the dew point with the emergence of a two-phase scenario. The heavier fractions of the previously single phase fluid begin to condense out at this point. An interesting phenomenon in gas condensate reservoirs is the re-vaporisation of the liquid. This occurs as the pressure crosses the lower dew point line. Ahmed [2] pointed out that the retrograde condensation process would continue with decreasing pressure until the liquid dropout reaches its maximum. As pressure further reduces the heavy molecules will begin the normal process of vaporization. This process allows fewer gas molecules to strike the liquid surface thereby causing more molecules to leave rather than enter the liquid phase. The process does not until the reservoir pressure reaches the lower dew-point pressure. The implication of this is that all the liquid that formed must vaporize since only vapours exist at the lower dew point of the system. Condensate reservoirs possess the most complicated flow and thermodynamic behaviours. The production of both gas and condensate liquid at surface conditions characterizes condensate reservoirs. Gas/liquid ratios of approximately 3:150 MCF/STB is produced by a normal condensate reservoir [3]. Natural gas liquids recovery from these accumulations must be undertaken in the vapour phase. This is because liquid saturation is retrograded within the reservoir at reduced pressures and is typically below the critical level at which the liquid will form a continuous phase which may flow or may be displaced as liquid [4]. Prevention or reduction of liquid loss as a result of retrograde condensation are achieved when the content of gas condensate reservoirs are displaced through cycling operations. This involves the separation of the liquefiable components of the produced gas condensate fluid and subsequent re-injection of the dry gas into the reservoir in order to maintain the reservoir pressure above the dew point to prevent further retrograde condensation. In the event that condensation has already taken place, the condensed liquid can be vaporized by injecting more gas into the reservoir thereby improving production [5].

2. Methodology

This work is comprised of two process segments. The reservoir and fluid pressure, volume and temperature (PVT) models were built first, and followed by a set of parametric study in order to determine the optimal strategy that promises highest condensate production.

2.1 Reservoir overview

Fluid samples were collected for the PVT analysis from a rich condensate reservoir, EME 221 in the Niger Delta, South-South Nigeria, and laboratory tests ran on the samples. The fluid has a dew point pressure of 4940psia. The reservoir was found at a temperature of 255^{o}F and a pressure of 5000psia. It is supported by a moderate aquifer.

2.2 Fluid PVT design

Precise and accurate characterization of a reservoir fluid is an imperative factor in reservoir simulation studies. In gas flooding processes, because of existence of a great interaction between injected and in place fluids, it is very important to characterize the reservoir fluid precisely. PVT experiments are usually expensive and time consuming, and usually performed in limited conditions. Therefore, EOS based PVT packages are used widely for the prediction and evaluation of fluid properties in well and surface conditions over a wide range of temperature, pressure and composition. Fluid samples were collected for the PVT analysis from a rich condensate reservoir, EME 221. ECLIPSE's PVT*i* for fluid characterization was used to develop the fluid PVT properties and the results were exported to ECLIPSE compositional simulator [6]. The simulator was used to match the saturation pressure of the laboratory derived data and that obtained from EOS. Heptane's plus fraction display a lot of uncertainty to the total fluid properties, therefore heptane's plus (C_{7+}) characterization and EOS tuning are used to resolve the uncertainty in the fluid properties. The C_{7+} fraction was split into three further fractions of C_{7+}, C_{14+}, and C_{25+} in order to achieve a better characterization of the heavier components of the fluid mixture. The components were then lumped into groups of pseudo-components. The lumping was accomplished to satisfy three requirements. First, the sum of the mole fractions of all components from C_7 to C_{25+} is equal to the mole fraction of C_{7+}. Second, the sum of the products of the mole fraction and molecular weight of the individual components from C_7 to C_{25+} is equal to the product of the mole fraction and molecular weight of the C_{7+}. Third, the sum of the product of the mole fraction and molecular weight divided by the specific gravity of each component from C_7 to C_{25+} is equal to that of the C_{7+}. After the pseudo-components were defined, the EOS tuning process was initiated with the 3-parameters. Peng Robinson Equation of State was selected for tuning the data obtained from laboratory experiments such as Constant Composition Expansion (CCE) and Constant Volume Depletion (CVD). The parameters selected for regression were the binary interaction coefficients (BICs), critical pressures, critical temperatures, and the shift factors.

2.3 Regression

After obtaining the CCE and CVD data, it is usually necessary to adjust the predicted EOS characterisation using non-linear regression to obtain an acceptable match. This tuning procedure is not usually straight forward. Appropriate parameters are being selected for adjustment based on experience. Several non-linear least-squares regression methods have been implemented and tested, of which the rotational discrimination method is recommended. A set of Binary Interaction Parameters (BIP) are adjusted until a good match is obtained between the simulated data and experimented data. These BIPs are used to enhance the predictive capabilities of an EOS used in Volume Liquid Equilibrium calculations of reservoir fluids. When a reasonable match is achieved with an error of 5%, then the EOS can be imported into a simulation model such as ECLIPSE100, which runs as a compositional model.

2.4 Reservoir model design

Real reservoirs are of course continuous, and all flow-dependent parameters change continuously with time. A reservoir simulator, which is a computer program, cannot, however, relate to continuous variables. It is therefore necessary to subdivide the continuous reservoir into a finite number of discrete elements, and also to define time development in a discrete sense. Then at any time, all properties will be understood as being constant within one element, and dynamic (time dependent) updates will occur only at defined time steps, while all data are seen as constant between such updates. The subdivision of the reservoir into finite volume elements or cells is denoted as discretisation of the reservoir, and the set of elements is called the reservoir grid. Intuitively, we would expect the simulator results to be more reliable if the grid closely approximates the reservoir itself. Since most real reservoirs have a complex geometry and internal structure, a good approximation will normally require a large number of cells. Computational considerations will on the other hand restrict the number of cells by available computer memory and/or acceptable run times, so the grid we used will almost always be a compromise between different desires [23]. The reservoir model used in this study is a three dimensional system. The model is made up of a 10×10×6 grid cell arrangement which corresponds to the x, y and z directions. That is, the reservoir was discretised into 10 cells in the x direction (along the length), 10 cells in the y-direction and 6 cells in the z-direc-tion totalling 600 grid cells. All cells in x direction were designed to be of an equal size of 310ft, 240ft for those in y-direction and 50ft in z-direction. All cells are active. The depth to the top of the reservoir is 9200ft representing the True Vertical Depth (TVD), and does not include the thickness of the reservoir. This depth was assumed to be uniform across reservoir tops in order to simplify the model, but real reservoirs are not horizontal. The initial reservoir pressure was 4953 psia. Petro-physical parameters used to describe the model include porosity, permeability and Net-to-Gross (NTG) thickness. Permeability in x-direction was greatly varied from 1300md to 1800md, however a uniform y-permeability was assumed. The Kv/Kh ratio of 0.13 was used to multiply x-permeability and their product was used as z-permeability as shown in table 3.5. The NTG ratio was initially assumed to be 1, however this value was later altered during the sensitisation runs in order to investi-gate its influence on condensate production. A set of hypothetical data were also used to complete Special Core Analysis (SCAL) section of the eclipse office.

2.5 Equilibration definition

The initial reservoir state is defined by the pressure and saturations in each grid cell at the start of the simulation. It is convenient to let the simulator calculate the initial state based on the reasonable assumption that the reservoir fluids are in equilibrium at no-flow conditions. We only need to supply the depths of the oil-water contact (WOC) and gas-oil contact (GOC), and the fluid pressures at a reference depth. However a gas-condensate system does not have a GOC or OWC, rather the only fluid-fluid contact that exists at the initial state of the reservoir is gas-water contact (GWC) since at this stage the pressure is above the dew-point and the hydrocarbon are in gaseous phase. The simulator can then calculate the necessary state from fluid weight versus depth gradients.

2.6 Aquifer modelling

The aquifer model used in this study was an edge water aquifer. Cater-Tracy model was selected for the calculation of water influx into the reservoir. Aquifer and aquifer connection parameters are tabled 1 below:

Table 1 Aquifer connection (con.) data

Aquifer ID	Lower I Con	Upper I Con	Lower J Con	Upper J Con	Lower K Con	Upper K Con	Connection face
1	1	1	1	10	6	6	I

Table 2 Aquifer parameters

Aquifer Id	Datum depth (ft)	Initial pressure (psia)	Permeability (mD)	Porosity	Total compressibility (/psi)	Radius (ft)	Thickness (ft)
1	9300	5000	100	0.22	2.87E-06	1500	120

The connection to the reservoir is set up by an arbitrary box defined by lower and upper I, J and K indices. Having defined the parameters for the reservoir and aquifer, the simulator generates the values of the fluid(s) in place as shown below:

Table 3 Initial fluid volumes

Region	Oil (Res Vol) (rb)	Water (Res Vol) (rb)	Gas (Res Vol) (rb)	Water (Surf Vol) (stb)	Oil (wrt Separator) (stb)	Gas (wrt Separator) (Mscf)
Field	0	43214424	70004139	41390960	2491702.9	93470450

2.7 Well specification

The well configuration is of 0.75ft diameter and depth of 9350ft for the production wells, and 9300ft for the injector. The production rate of each well is 12400mscf/d. The injection rate was varied based on percentage of total field production. Figure 2: shows grid block design and well placement.

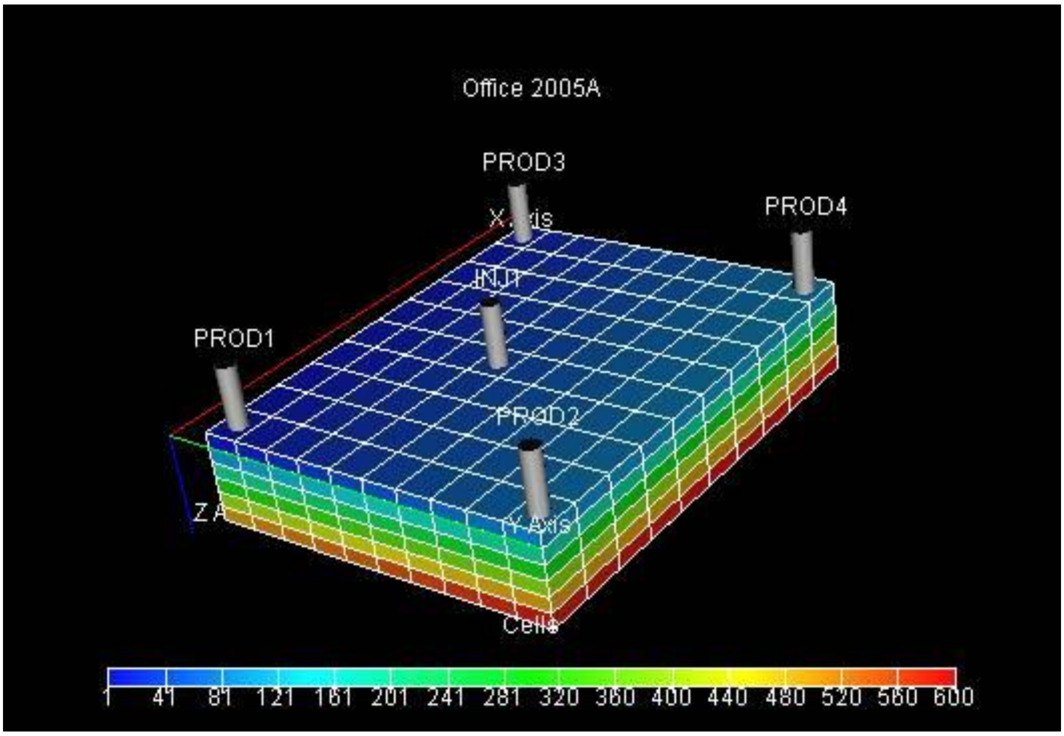

Figure 1 Reservoir grid block and well placement

Having explained earlier that the reservoir petrophysical parameters vary, it becomes imperative to choose a well placement pattern that would guarantee optimum fluid production. In addition, it is important to make this choice bearing in mind the possibility of drilling new injection or even production wells In the future. A 5-spot pattern was arbitrarily chosen since it is the mostly used pattern. In this pattern, each injection well is located at the centre of a square defined by four production wells.

2.8 Sensitivity analysis

Condensate production is severely affected by both reservoir features and production parameters as a result of uncertainty associated with the parameters. It became necessary to identify the parameters that mostly influence condensate recovery. The complete model was used to determine the effect of NTG ratio, Kv/Kh ratio, injection rate, and injection pressure on recovery.

3. Result and discussion

At the completion of the modelling, the four production wells were initially set on production at a constant rate of 15000mscf/day for fifteen years and the corresponding parameters of study were recorded. Subsequently some alterations were made both in the relatively contact variables and the operational ones and the results are discussed below.

3.1 Depletion case

During the depletion scenario, gas-condensate reservoir was depleted very fast. The retrograde condensate occurs in lower layers around the producers due to reservoir depletion. Condensate is immobile phase, therefore production sharply goes down. When gas production rate was increased, the field was depleted much faster due to mass balance. The field's GOR was observed to be 37.573mscf/stb during the first 2463days but witnessed a sharp increase to a constant value of 71.49mscf/stb throughout the simulation period. There was a rapid decline in the production rate as soon as wellbore banking set in. These are shown below.

3.2 Sensitivity of pressure effect

A constant injection rate of 10200mscf/day was maintained while the injection pressures were varied in the five different runs. The total condensate production at the end of the simulation period is presented in Figure 2.

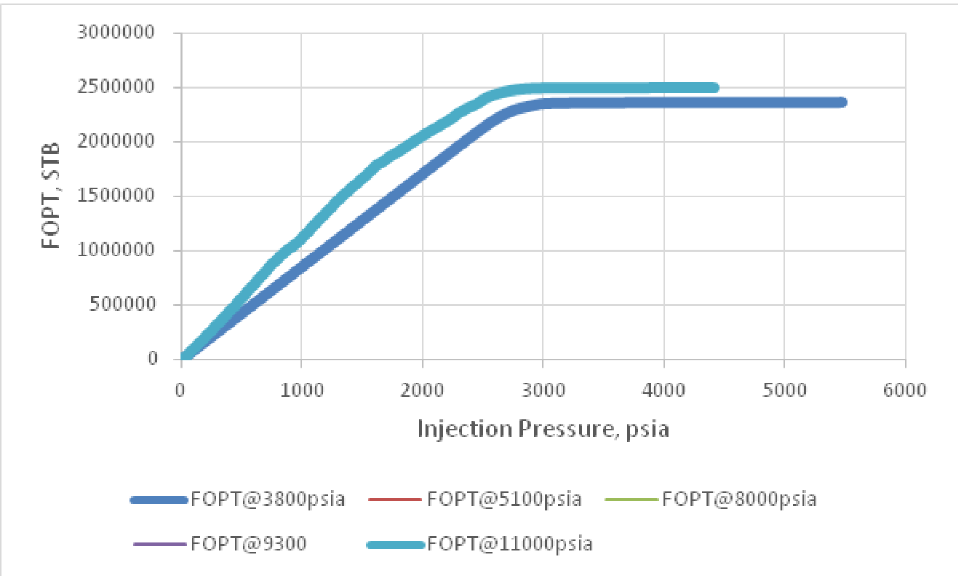

Fig.2 Effect of injection pressure on field oil production total (FOPT)

From the set of plots generated, it is clear that injection pressure(s) below the reservoir fluid dewpoint recorded minimum effect on the total condensate production, and injection above dew point yielded maximum production. This trend was also observed when these injection pressures were adopted at the injection rates of 14,600mscf/day and 6000mscf/day. This is because flow will still be prevented by the liquid dropout around the wellbore.

3.3 Sensitivity on the effect of injection rate

The model was run by varying the injection rates at a fixed injection pressure. The rate was the control variable in this case. A constant pressure of 5000psia was selected for these runs. The figure 3 depicts the scenario.

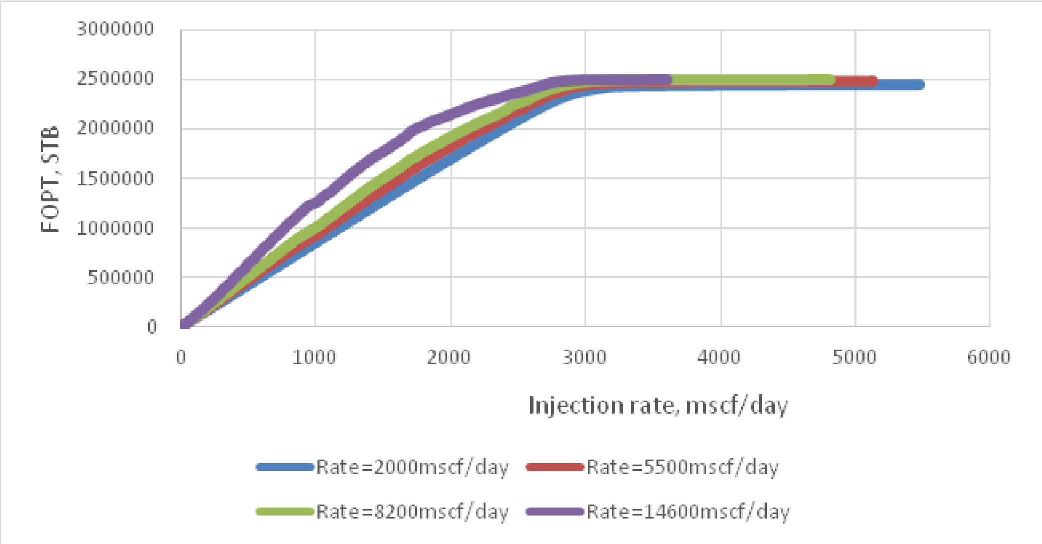

Figure 3 Effect of injection rate on field oil production total

The plot shows that condensate recovery increases with injection rate until the water overruns the gas zone or the volume of gas-condensate in the reservoir is fully depleted. It must be noted that at higher injection rates, the total condensate production became constant. This could be because the production wells are constrained to a constant rate.

3.4 Effects of fluid contact(s) on condensate recovery

At initial conditions, gas-condensate reservoirs maintain only one fluid-fluid contact, (the gas-water contact, GWC). Three Sensitivity runs were completed assuming three different GWC points of 9400ft, 9450ft and 9490 ft respectively as shown in figure 4.

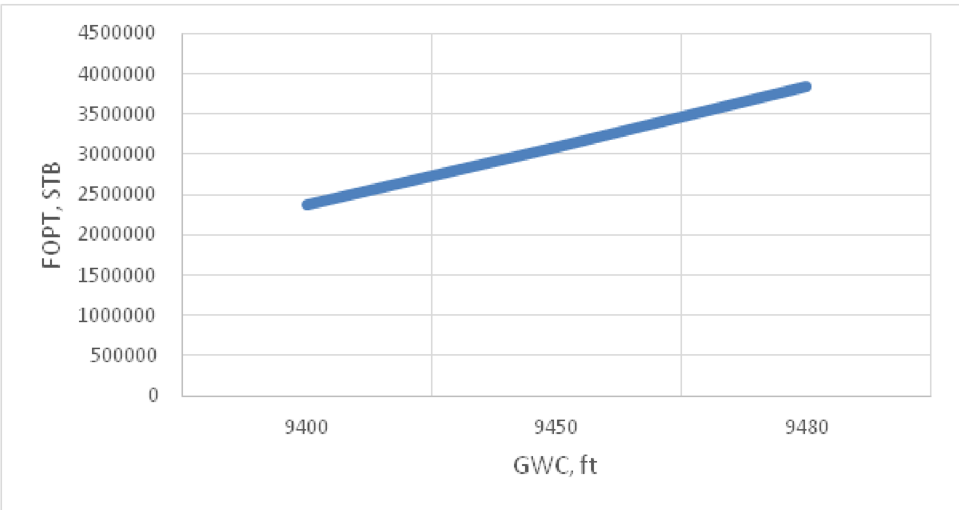

Figure 4 Effect of GWC on field oil production total

The result shows that total condensate production is proportional to increase in the GWC depth. This is because the gas condensate in place equally increases with GWC. The increments tend to be exponential because the reservoir model was built to have higher porosity and permeability values at increased depths.

3.5 Effects of NTG ratio on total condensate recovery

The NTG ratio is simply the fraction of the entire reservoir that contains oil. It plays a vital role in volumetric estimation of reserves since it helps account for the presence of intra-reservoir shales. This value is less than unity if there exist shale inter-beds in the reservoir. In this sensitivity runs, five values were chosen in descending order and the total condensate production for each case was presented in figure 5.

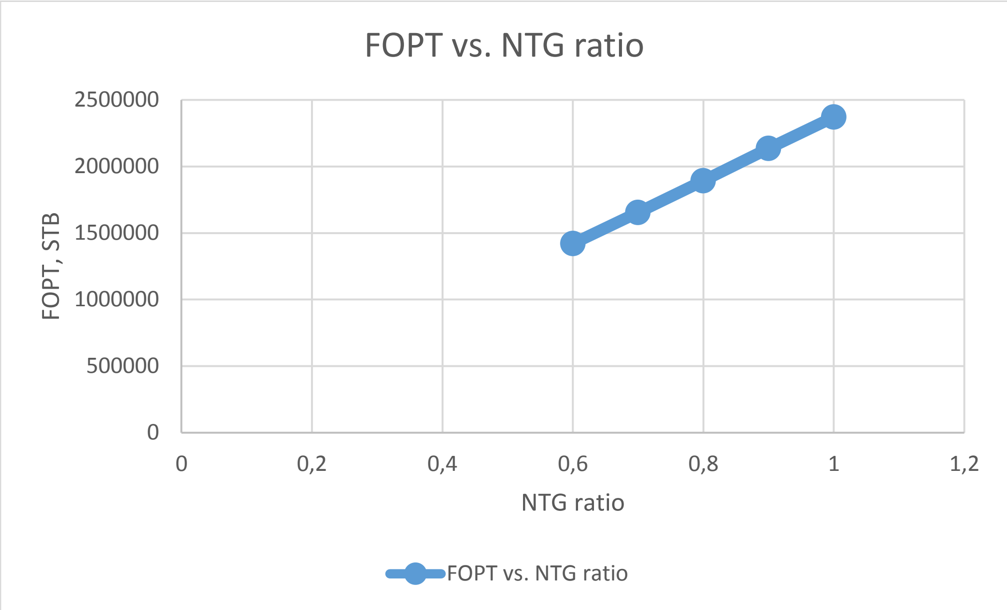

Figure 5 Effect of NTG ratio

From the plot above, the NTG ratio has a very large impact on condensate production as a mere 10% presence of shale inter-bed caused a whooping 236520stb of condensate recovery.

4. Conclusion

Gas-condensate reservoirs are a very unique kind of hydrocarbon reservoir both in their behaviour and economic attention they command. However, effective production of this very valuable fluid is not without stiff challenges. The condensation of the heavier fractions of the formally gaseous hydrocarbon at reduced pressures poses a great concern to operators of such reservoirs, because of the wellbore blockage effect and subsequent fall in production that emanates from such a process. This project has utilised ECLIPSE Compositional simulator to show that the injection of the produced gas is promising solution to this problem. This project considered some parameters (both operational and relatively fixed) that would affect the efficiency of gas recycling in gas-condensate reservoirs, and the study showed that injection pressure only make positive impact if it is higher than the dewpoint pressure of the fluid. Also at any fixed injection pressure, the higher the injection rate the more condensate was recovered. The NTG ratio and GWC point which were equally studied portrayed very high effect on total condensate recovery, but they are seemly fixed rather than operational factor. Therefore in a real gas condensate optimisation they are expected to receive less attention since the operator cannot vary them.

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