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Optimizing Liquid Recovery from a Gas Condensate Reservoir Operating below Dew Point

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ABSTRACT

Fluid flow in gas condensate reservoir is very complex and involves phase changes, multiphase flow of the fluid, phase redistribution in and around the wellbore and retrograde condensation. This study seeks to evaluate the effect of hydraulic fracturing on gas and liquid production of gas condensate reservoir with pressure below dewpoint. This research utilised a compositional simulator (Eclipse 300) with a single vertical well model, relative permeability model, fluid and PVT parameters to model a gas condensate reservoir operating below dewpoint. Two cases were investigated. Case 1 is a control scenario where the reservoir was unfractured and allowed pressure to deplete using the reservoir energy. Case 2 represents a hydraulic fractured reservoir to ascertain the effect of fracturing on liquid and gas production. The hydraulic fracturing job was done using dual porosity dual permeability condensation model in Eclipse 300 with a conductive fracture attached closer to the wellbore with various fracture parameters. After ten years of production, the cumulative liquid production was 957803STB for the unfractured case. Fracturing the reservoir at fracture halflength of 1000ft, fracture width of 0.03ft, fracture permeability of 1000md gave a cumulative liquid production of 1055936STB after ten years of production. Increasing the fracture halflength to 2000ft, fracture width to 0.06ft, fracture permeability to 2000md gave a total liquid production of 1056137STB. Further increase of fracture halflength to 3000ft, fracture width to 0.1ft and fracture permeability to 3000md gave a total liquid production of 1057139STB. The result obtained showed that continuous increase in fracture parameters may not result to an economic liquid recovery. Based on cumulative liquid production and economic feasibility of the project, a fracture halflength of 1000ft, fracture width of 0.03ft and fractured permeability of 1000md proved optimal for the reservoir considered.

Key words: Optimizing; Liquid Recovery; Gas Condensate Reservoir; Operating; Below; Dewpoint

INTRODUCTION

Gas condensate reservoir also known as retrograde gas condensate reservoir is of economic importance as a result of the additional liquid produced when the reservoir pressure drops below dewpoint. Maximum recovery from this reservoir during the developmental and operational stages requires an engineering and operating method significantly different from crude-oil or dry-gas reservoirs. Cenk *et al* [1] defined Gas condensate reservoir as a reservoir that contains a thermodynamically special kind of reservoir fluid; its reservoir temperature is above the critical temperature (T_C) but less than the cricondentherm (T_{Ct}) on the phase diagram. Isothermal production of the reservoir fluid results in an attendant pressure decline. When the entire reservoir pressure drops below the dew point pressure, liquid drops out of the gas phase and forms condensate throughout the whole reservoir in a process called condensate banking. This gives rise to the emergence of a two-phase scenario thus, causing a reduction in the relative permeability of gas thereby leading to a dramatic decrease in the productivity of the well [2]. If the condensate saturation exceeds the critical condensate saturation ($\mathbf{S_{cc}}$), both gas and condensate will flow.

Previous researchers such as Fussel 1973, Barnum et al 1995, Muskat 1949 [3-5] etc have reported significant losses of well deliverability in gas/condensate reservoirs because of condensate banking. Engineers can devise ways to optimize the production of gas and condensate by proper understanding of where and how condensate drops out of the gas phase.

A combination of factors gives rise to condensate banking. These factors include fluid phase properties, pressures in the formation and in the wellbore. Failure to understand these factors at the beginning of field development will cause production performance to suffer. Gas-condensate reservoirs experience reductions in productivity by as much as a factor of 10 due to the dropout of liquid close to the wellbore. This case of condensate banking is seen in Arun field, North Sumatra in Indonesia, where well productivity declined significantly by a factor of more than two about 10years after production began. This was a serious problem, since well deliverability was critical to meet contractual obligation for gas delivery. Well studies including pressure transient testing, indicated the loss was caused by the accumulation of condensate near the wellbore

Over the years different methods have been used to reduce the effect of liquid drop out due to the drop in reservoir pressure below the dew point. Generally, these methods are grouped into four [6-7]. Namely:

1. Pressure maintenance aimed at keeping the reservoir pressure above dewpoint to prevent the formation of condensate through fluid injection.
2. Productivity improvement aimed at increasing productivity of the well through hydraulic fracturing and horizontal well drilling.
3. Chemical treatment to change the interfacial tension and relative permeability.
4. Use of combined methods which integrates different methods.

LITERATURE REVIEW

From the vast literature survey, it is clear that in the past many researchers have done a lot of research on gas condensate reservoir and the various ways to optimize production from this reservoir. Consequently, many studies have been conducted since the 1950's to understand the behaviour of gas condensate reservoirs below the dewpoint pressure and to identify the main controlling parameters. A brief insight to some of the literature reviewed during the research is outlined below:

Zeeshan et al [8] highlighted the effect of fracture face skin damage associated with the length and width of hydraulic fractures. In their study suggested that while designing fracture operations for gas condensate reservoirs, one should keep the fracture half-length, fracture width and fracture permeability high while fracture face skin should be small around the vicinity of the wellbore.

Carvajal et al [9] presented a paper on the impact of pertinent parameters on the design of hydraulic fracturing in gas condensate reservoirs. The result showed that not only inertia was important but also positive coupling strongly affected the flow performance. For a tight formation, positive coupling in the matrix can overcome negative inertia in the fracture region. Also wide fractures reduce the inertia effect significantly.

Ignatyev et al. [10] evaluated hydraulic fracturing in horizontal wells as a method for the effective development of gas/condensate fields in the Arctic region (Russian). They found that the productivity of horizontal wells with fractures was nine times greater than the production from horizontal wells without fractures and three times greater than vertical wells with fractures. They concluded that multistage fracturing in horizontal wells reduced the drawdown and condensate losses and raised the well PI.

Ravari et al [11] presented a paper on gas condensate damage in hydraulically fractured wells. In their study used compositional reservoir simulation to model production for three situations: all having low permeability with hydraulic fractures. The simulation result verify what was observed in the field: lower wellbore pressures yields higher production rates. Although some condensate damage was observed below the dewpoint, none of the cases showed that lower wellbore pressures led to worse overall well performance. Even for the case of a very rich gas condensate, the optimum conditions correspond to the lowest Pwf.

M. Ebrahimi [12] carried out a parametric study of condensate build up in a naturally fractured gas condensate reservoir. He used a compositional model to predict and physically justify the single-well performance of a naturally fractured gas condensate reservoir having different reservoir properties and production schemes. He investigated the combination of fluid thermodynamics and rock physics that result in condensate drop out and compositional changes throughout the reservoir. His study reveals the important role of capillary pressure in trapping condensate, especially in highly fractured reservoirs where the effect of gravity drainage is minimized. Higher matrix block sizes can reduce the amount of trapped liquids. The amount of condensate saturation is higher for a higher critical saturation value. Pore size uniformity is another important factor that causes less condensate build up due to less capillary pressure. Higher production rate results in earlier condensate dropout peak.

Roussennac [13] illustrated the phase change during the depletion in his numerical simulation. According to Roussennac, during the draw down period, with the liquid building up in the well grid cell, the overall mixture in that cell becomes richer in the heavy component, and the fluid behaviour changes from the initial gas-condensate reservoir to that of a volatile/black oil reservoir.

Adegbola and Boney [14] studied the effect of fracture face skin damage in both high and low permeability heterogenous retrograde gas condensate reservoirs and found that the effect of fracture face skin is only prominent in high permeability reservoirs due to high fluid loss; on the other hand in low permeability reservoirs this effect is negligible.

General Characteristics of Gas Condensate Reservoir Fluid

A typical gas condensate fluid exhibits the following characteristics:

GOR: 3,000-100,000SCF/STB

API: $40\text{-}70^0$

COLOUR: Light

C_7^+ COMPOSITION: <12.5%

Table -1 Composition of a Typical Gas Condensate Fluid [1]

Component	Composition (Mole %)
C_1	87.09
C_2	4.37
C_3	2.31
C_4	1.72
C_5	0.81
C_6	0.62
C_7^+	3.80
Mw C_7^+	115

Table 1 above summarizes the composition of a typical gas condensate fluid.

Flow Behaviour of Gas Condensates

According to Al-Yami et al [15], Fevang and Whitson [16], when the condensate forms near the wellbore, it creates three different mobility regions in the reservoir as shown in Figure 1 below. In region 3, where the fluid pressure is still above the dew point pressure, there is only a single gas phase present. This region is farthest away from the wellbore. 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 behaviour of the fluids in these two regions to be able to mitigate condensate banking effects.

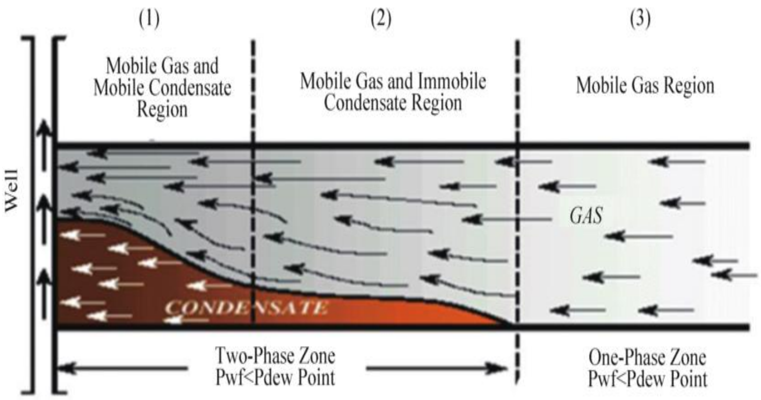

Fig. 1 Three Flow Regions of a Gas Condensate Reservoir due to Pressure Drop [7]

According to Economides et al. [17], Fussel [3], Gringarten et al. [18] and Marokane et al [6], there may also exist a fourth region in the immediate vicinity of the wellbore where low interfacial tensions (IFT) at high rates yield a decrease of the liquid saturation and an increase of the gas relative permeability.

METHODOLOGY

In this study, hydraulic fracturing was used to simulate the production performance of FRAC1, a Niger Delta Gas Condensate Reservoir operating below dew point. The reservoir was simulated using rock and fluid properties obtained from the reservoir of study. In the bid to achieve the objective of this study, the research was divided into two (2) parts. These are outlined below:

1. The first part of the study involved building a static model of the reservoir of study using a Compositional Simulator (Eclipse 300) and adequately placing the production wells with proper completion philosophy.
2. Proper reservoir fluid characterisation was done using PVTp in Petroleum Expert with adequate Equation of State (EOS) Model, simulating the depletion process by entering the PVT experiment data i.e CCE and CVD data into PVTp, using nonlinear regression in PVTp to obtain a match between the EOS predicted parameters and laboratory observed parameters and exporting the fluid model into a compositional simulator for full field simulation study.

Reservoir Description

A hypothetical 3D Cartesian Reservoir with a Compositional simulator (Eclipse 300) was used to simulate the isothermal depletion process of a gas condensate reservoir as its pressure dropped below dewpoint. A 25 x 25 x 10 grid block reservoir was built with the size of each grid to be 250ft in the X and Y axes and 100ft in the Z axis. The permeabilities in the X and Y axes are same (i.e Kx = Ky = 500md) and Z axis (Kz = 50md). The Reservoir Rock and fluid properties are outlined in the table below:

Table -2 Reservoir rock and fluid Properties

S/N	Reservoir Properties	Value	Unit
1	Initial Reservoir Pressure	4868	Psia
2	Reservoir Temperature	176.6	^oF
3	Reservoir Area	897	Acres
4	Dew Point Pressure	4191	Psia
5	Average Permeability	500	Md
6	Permeability Ratio (K_v/K_h)	0.1	
	Net to Gross Thickness Ratio (NTG)	0.8	
7	Porosity	20	%
8	Reservoir Depth	10800	Ft
9	Reservoir Thickness	100	Ft
10	Liquid Density at Dew Point	14.858	lb/ft^3
11	Water Density	63	lb/ft^3
12	Water Compressibility	0.000003	1/psi
13	Rock Compressibility	0.000004	1/psi
14	Connate Water Saturation	15	%

The reservoir model as built with Eclipse 300 is shown below:

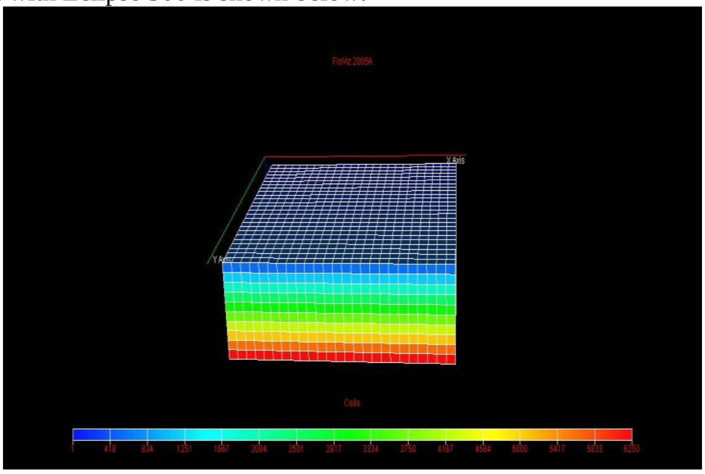

Fig. 2 Reservoir Model

Well Model, Location and Completion Data

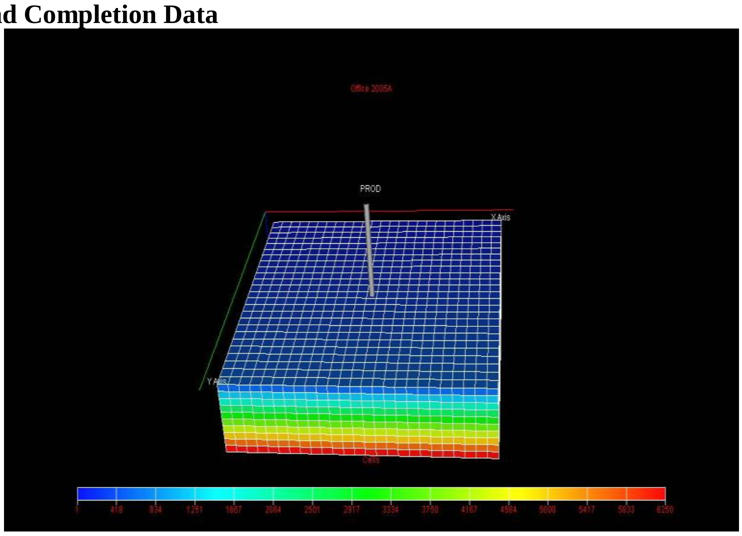

Fig. 3 Reservoir Model with Vertical Well at the Center of the Drainage Area

The reservoir was isothermally depleted below its dewpoint pressure using a Single Vertical Well Model as the base case. The vertical well was isothermally depleted from an initial reservoir pressure of 4868psia until its pressure declined below dewpoint ($P_{dewpoint}$ = 4191psia). This vertical well served as a control case to monitor the behaviour of gas condensate well as its pressure declined below dewpoint. The vertical well was perforated within five layers of the reservoir with an I.D of 0.5ft, a bottom-hole pressure target of 1000psia and it is located in the center of a square drainage area as shown below:

Reservoir Fluid and PVT Model

The reservoir fluid is a lean gas condensate fluid with an API of 45.7^0, a GOR of 56.9MSCF/STB and a Condensate Gas Ratio of 17.6STB/MMSCF. The reservoir fluid was defined by entering its components and the corresponding mole fractions. The laboratory PVT (CCE and CVD) data of the reservoir fluid obtained from the reservoir of study was used to design the equation of state (EOS) model using PVTp. In this EOS modeling, Peng-Robinson 3-parameter (PR-EOS) was used to develop proper reservoir fluid characterization and fluid viscosity was calculated using Lohrenz-Bray-Clark Correlation as specified in PVTp. The simulator was used to match the saturation pressure of the laboratory derived data and that obtained from PR-EOS until a close match was obtained. The observed dew point pressure is 4191psia while that calculated using PR-EOS is 4114psia.The reservoir fluid components are given in the table below:

Table -3 Reservoir Fluid Components

S/NO	Components	Weight Percent (wt %)	Mole Percent (Mol %)
1	N_2	0.19	0.14
2	CO_2	0.37	0.18
3	H_2S	0.00	0.00
4	C1	66.06	87.26
5	C2	7.45	5.25
6	C3	5.85	2.81
7	IC4	1.84	0.67
8	NC4	2.47	0.90
9	IC5	1.40	0.41
10	NC5	1.06	0.31
11	C6	2.26	0.57
12	C7+	11.07	1.5
	TOTAL	**100.00**	**100.00**
	MOL WT OF C7+ = 171.95 **S.G OF C7+ = 0.8086**		

Optimizing Production from the Reservoir of Study

In order to optimize condensate recovery from the reservoir, the reservoir was hydraulically fractured so as to increase the conduit past the condensate blocked near wellbore region. The hydraulic fracturing job was done using the Dual Porosity Dual Permeability Condensation Model with Fully Implicit Solution as specified in the Runspec section in Eclipse 300 using the keywords DUALPORO and DUALPERM respectively. The dual porosity model assumes that the fluid exists in two interconnected systems: The rock matrix, which usually provides the bulk of the reservoir volume and the highly permeable rock fractures. The matrix block size is 50ft and it is specified in Eclipse 300 using the keyword DZMTRX. The matrix-fracture transmissibility multiplier was simulated by using the keyword SIGMA as specified in the grid section of Eclipse 300. This multiplier was calculated using Kazemi [19] model expressed in the equation below:

$$\sigma = 4\left(\frac{1}{l_x^2}+\frac{1}{l_y^2}+\frac{1}{l_z^2}\right)$$

where l_x, l_y and l_z are typical X, Y and Z dimensions of the matrix blocks.

$\sigma = 0.0016$

After this a conductive fracture was attached to the reservoir by using the keyword CONDFRAC as specified in the grid section of the simulator. Three cases were simulated to observe the effect of varying fracture properties on the quantity of liquid produced.

CASE 1: Fracture Halflength (X_f) = 1000ft, Fracture Width (W_f) = 0.03ft, Fracture Permeability (K_f) = 1000md

CASE 2: Fracture Halflength (X_f) = 2000ft, Fracture Width (W_f) = 0.06ft, Fracture Permeability (K_f) = 2000md

CASE 3: Fracture Halflength (X_f) = 3000ft, Fracture Width (W_f) = 0.1ft, Fracture Permeability (K_f) = 3000md

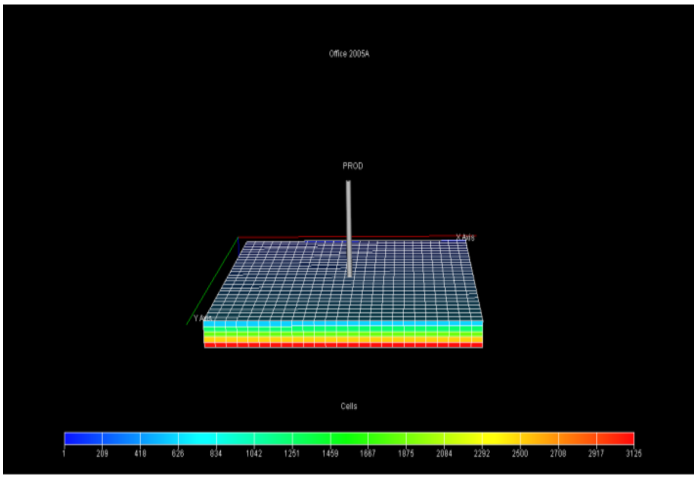

Fig. 4 Dual Porosity Dual Permeability Model

RESULTS AND DISCUSSION

The results of the Laboratory PVT experiment basically CCE and CVD data were entered into PVTp, non-linear regression using Peng-Robinson 3-Parameter EOS in-built in PVTp was used to match the laboratory data and the EOS calculated data until a close match is obtained. The observed saturation pressure is 4191psia while the EOS calculated saturation pressure is 4114psia. This close match shows that the reservoir modelled fluid is a representative of what is in the reservoir. The reservoir conditions are as follows:

1. Initial Reservoir Pressure: 4868psia
2. Dew Point Pressure: 4191psia
3. Reservoir Temperature: 176.6^{0}F
4. Condensate to Gas Ratio: 17.6STB/MMSCF

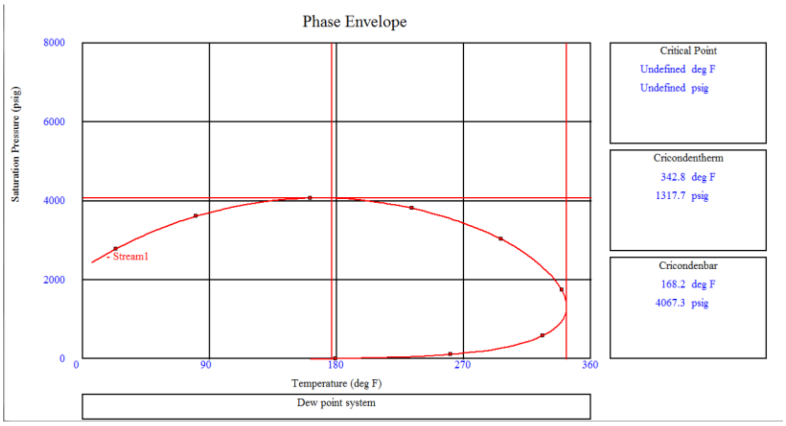

Fig. 5 Phase Diagram of the Reservoir Fluid

Results of the Various Matched PVT (CCE and CVD) Experimental and EOS Calculated Data

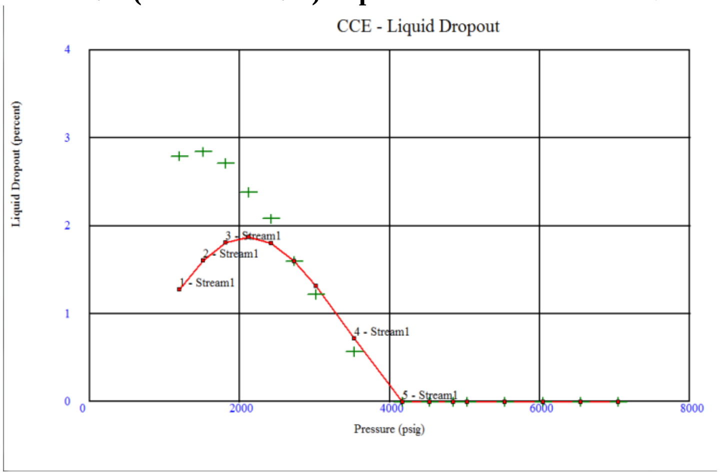

Fig. 6 Matched CCE Liquid Dropout Curve

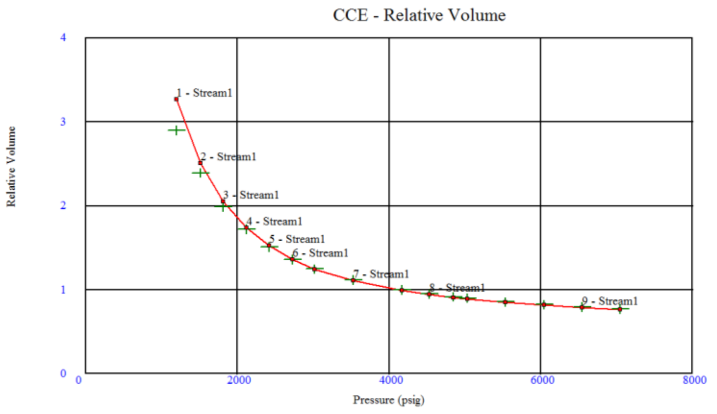

Fig. 7 Matched CCE Relative Volume Curve

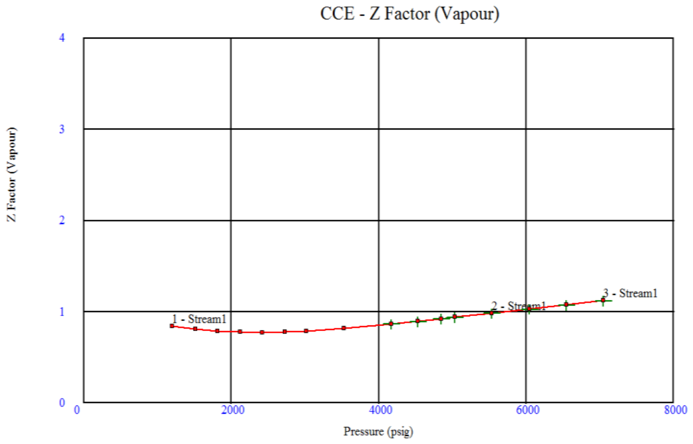

Fig. 8 Matched CCE Z-factor (Vapour) Curve

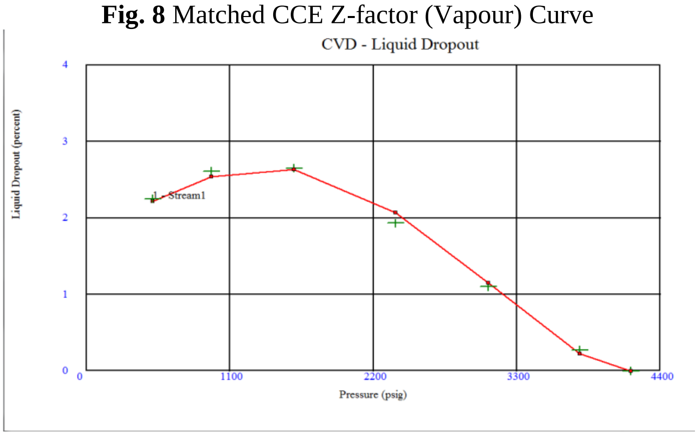

Fig. 9 Matched CVD Liquid Drop out Curve

The result and the analysis of the two scenarios considered was interpreted using the following plots generated from the compositional simulation run on the gas condensate reservoir of study. During the simulation the following assumptions were made

i. The reservoir is assumed to be Rectangular in shape
ii. The reservoir pressure is initially at 677psia above dewpoint.
iii. Capillary pressure was neglected
iv. No form of pressure maintenance was considered
v. A critical condensate saturation (Scc) of 0.23 was used throughout the simulation
vi. The production well was produced at a constant rate of 40000MSCF/D

Hydrocarbon in Place Description

The volumetric estimate of the reservoir shows that the reservoir contains 1.1318673E+8rb of Gas Initially in Place.

Cases Considered

Case One: Natural Depletion without Induced Fracture

This is the case where the reservoir was unfractured and production of the reservoir fluid was done using the natural energy inherent in the reservoir.

Case Two: Natural Depletion with Induced Fracture

Here, the reservoir in case one was hydraulically fractured so as to enhance liquid production when the reservoir pressure dropped below dewpoint. During the hydraulic fracturing job, three hydraulic fracturing parameters were considered so as to obtain the optimum fracture parameters. These are:

1. At X_f = 1000ft, W_f = 0.03ft, K_f = 1000md.
2. At X_f = 2000ft, W_f = 0.06ft, K_f = 2000md.
3. At X_f = 3000ft, W_f = 0.1ft, K_f = 3000md.

The result obtained was analysed in terms of FGPT, FGPR, FLPT, FLPR and FPR

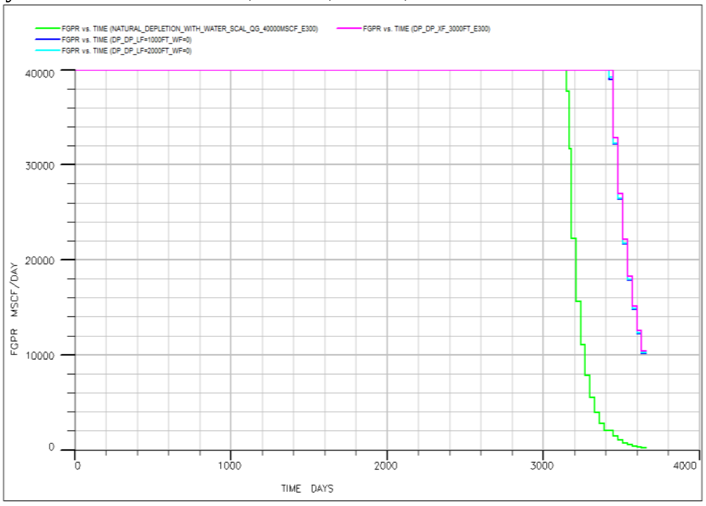

Fig. 10 Plot of FGPR against Time for the different Cases Considered

Figure 10 above shows that a gas production rate of 40000MSCF/D was maintained in the unfractured case till after 3165days when the gas production rate declined to 37733MSCF/D. This is followed by a step-wise decline in the gas production rate until a low rate of 188MSCF/D was recorded at the end of the simulation period. Fracturing the reservoir at fracture parameter of Xf =1000ft, Wf = 0.03ft, Kf = 1000md, had the gas production rate of 40000MSCF/D maintained until after 3450days when the gas rate declined to 39001MSCF/D followed by a step-wise decline in gas rate until a low gas rate of 10154MSCF/D was observed at the end of the simulation period. Increasing the fracture properties to Xf = 2000ft, Wf = 0.06ft and Kf = 2000md showed a constant gas production rate of 40000MSCF/D Until after 3450days of production when the gas rate declined to 39234MSCF/D. Further increase in fracture properties to Xf = 3000ft, Wf = 0.1ft and Kf = 3000md showed a constant gas production rate (40000MSCF/D) until after 3480days of production when the gas rate declined to 32829MSCF/D.

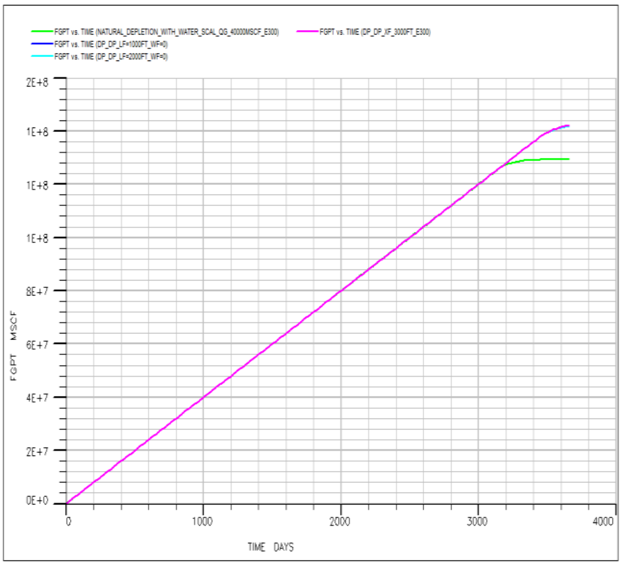

Fig. 11 Plot of FLPR against Time for the different Cases Considered

Figure 11 above shows a slight increase in the total gas production in the fractured case when compared with the unfractured case. This increase is witnessed after 3200days of production. The unfractured case recorded 1.2936623E+8MSCF total gas production after 10years of production. Fracturing the reservoir at Xf = 1000ft, Wf = 0.03ft, Kf = 1000md recorded 1.4202787E+8MSCF total gas production after 10years of production. Increasing the fracture parameters to Xf = 2000ft, Wf = 0.06ft and Kf = 2000md recorded 1.4205059E+8MSCF total gas production. Further Increase of fracture parameters to XF = 3000ft, Wf = 0.1ft and Kf = 3000ft recorded 1.4214498E+8MSCF total gas production.

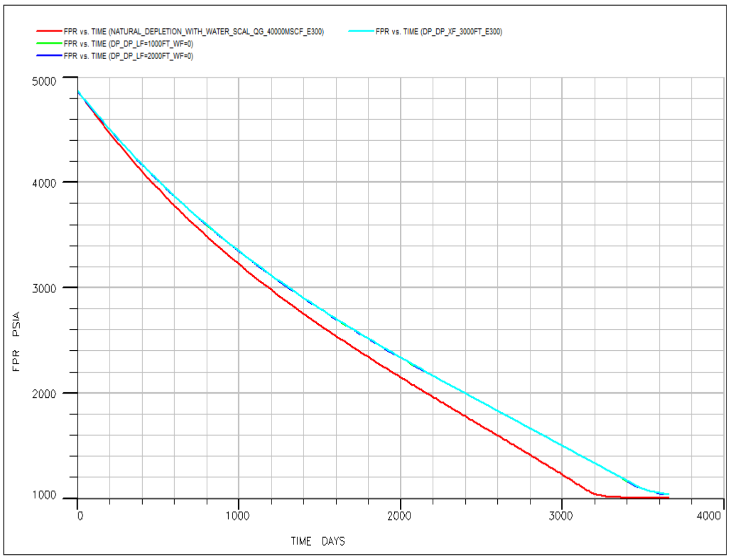

Fig. 12 Plot of FPR against Time for the different Cases Considered

From figure 12 above, the reservoir pressure in the unfractured case declined below its dewpoint (4191Psia) after 360days of production (4176Psia). Fracturing the reservoir at fracture parameter of Xf = 1000ft, Wf = 0.03ft and Kf = 1000md, had the reservoir pressure declined below dewpoint after 390days of production (4186.4Psia). Increasing the fracture parameters to Xf = 2000ft, Wf = 0.06ft, Kf = 2000md and Xf = 3000ft, Wf = 0.1ft, Kf = 3000md had the reservoir pressure declined below dewpoint after 390days of production i.e 4186.5Psia and 4189.2Psia respectively.

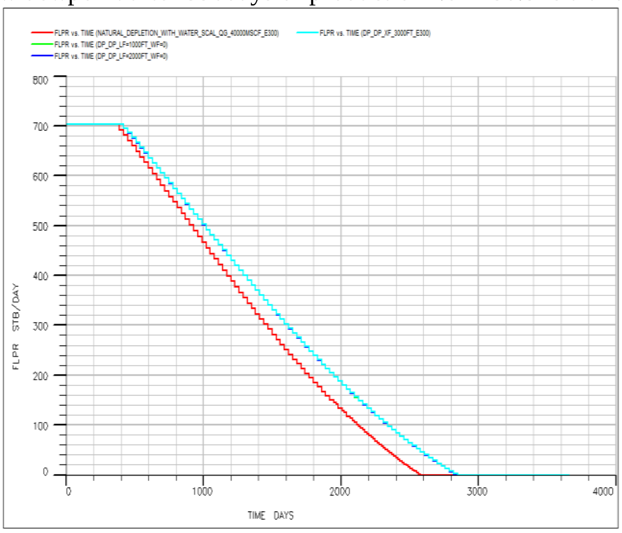

Fig. 13 Plot of FLPR against Time for the different Cases Considered

Figure 13 above shows that for the unfractured reservoir, the liquid production rate at the start of production was observed to be 703.3STB. This rate was maintained till after 390days of production when a step-wise decline in liquid production rate was observed as the reservoir is depleted due to production. This decline in liquid production continued until after 2595days when 0STB of liquid was observed till the end of the simulation period. Fracturing the reservoir at fracture parameter of Xf = 1000ft, Wf = 0.03ft and Kf = 1000md, had this liquid rate (703.3STB) maintained till after 450days of production when this liquid rate declined to 695STB/D followed by a step-wise decline. This step-wise decline in liquid production rate continued until after 2880days when 0STB was recorded. Increasing the fracture properties to Xf = 2000ft, Wf = 0.06ft and Kf = 2000md, this same liquid rate was maintained till after 450days of production when this liquid rate declined to 695.2STB/D followed by a step-wise decline as seen in the plot above. Further increase in the fracture parameter to Xf = 3000ft, Wf = 0.1ft and Kf = 3000md had this liquid rate (703.3STB) maintained but declined to 695.5STB/D after 450days of production followed by a stepwise decline in liquid production rate.

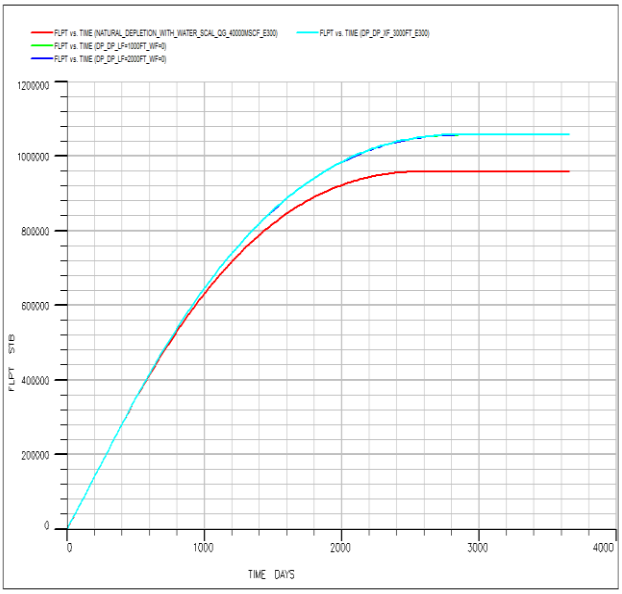

Fig. 14 Plot of FLPT against Time for the different Cases Considered

Figure 14 above shows an increase in the total liquid production from the reservoir. The total liquid production in the unfractured case continued to increase until after 2580days of production when the total liquid production (957802.8STB) was observed to remain constant until the end of the simulation period. At fracture parameter of Xf = 1000ft, Wf = 0.03ft and Kf = 1000md, the total liquid production continued to increase until after 2850days of production when it was observed to be constant (1055935.5STB) till the end of the simulation period. Increasing the fracture parameters to Xf = 2000ft, Wf = 0.06ft and Kf = 2000md, had the total liquid production increasing until after 2850days of production when it was observed to be constant (1056136.6STB) till the end of the simulation. Further increase in fracture parameters to Xf = 3000ft, Wf = 0.1ft and Kf = 3000md had the total liquid production increasing until after 2850days of production when it was observed to be constant (1057138.6STB) till the end of the simulation.

CONCLUSION

The result from the research showed that hydraulic fracturing can help to recover the liquid phase as the reservoir pressure drops below the dewpoint. Performance of hydraulic fracturing is dependent on the operational fracture parameters. The result showed that the optimum fracture parameter for the reservoir of study is at Xf = 1000ft, Wf = 0.03ft and Kf = 1000md. Increasing the fracture halflength (Xf), fracture width (Wf) and fracture permeability (Kf) above this optimum fracture parameter did not result to a significant increase in the recovery of the liquid phase when the reservoir pressure dropped below dewpoint. Thus, the additional liquid recovered due to increase in fracture parameters did not justify the economics of the hydraulic fracturing project.

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APPENDIX

RESERVOIR AND STANDARD CONDITIONS

Reservoir Depth = 10800FT, Reservoir Temperature = 176.6^{0}F, Reservoir Pressure = 4868Psia, Dewpoint Pressure = 4191Psia, Standard Temperature = 60^{0}F, Standard Pressure = 14.65Psia

CHARACTERIZED FLUID PROPERTIES

Component	Percent	T. Crit.	P. Crit.	Accent. Fact.	V. Crit.	Mole Wt
		deg F	psia		ft3/lb.mole	
N2	0.14	-203.361	544.816	8.99372e-00	1.43842	28.01
CO2	0.18	159.547	1188.08	0.00055115	1.50409	44.01
H2S	0.0001	300.622	1446.17	0.00018679	1.57938	34.1
C1	87.2599	-71.4706	745.297	2.53669e-00	1.58899	16.04
C2	5.24999	161.93	784.352	0.00022830	2.37547	30.1
C3	2.81	293.393	683.623	0.00035283	3.25166	44.1
IC4	0.669999	371.098	585.823	0.00042201	4.21274	58.1
NC4	0.899999	405.715	609.745	0.00045891	4.08459	58.1
IC5	0.41	478.696	534.889	0.00052348	4.90151	72.2
NC5	0.31	496.554	542.049	0.00057882	4.86948	72.2
C6	0.569999	574.055	486.884	0.00068951	5.92667	86.2
PS-1	1.5	891.536	357.411	0.00103032	11.3258	156.37

BINARY INTERACTION COEFFICIENT (BIC)

	N2	CO2	H2S	C1	C2	C3	IC4	NC4	IC5	NC5	C6	PS-1
N2		-0.02	0.165	0.036	0.05	0.085	0.095	0.095	0.095	0.095	0.1	0
CO2	-0.02		0.097	0.1	0.13	0.135	0.13	0.13	0.125	0.125	0.125	0
H2S	0.165	0.097		0.085	0.075	0.075	0.06	0.06	0.06	0.06	0.05	0
C1	0.036	0.1	0.085		0.002	0.007	0.012	0.012	0.017	0.018	0.024	0.29535
C2	0.05	0.13	0.075	0.002		0.001	0.003	0.003	0.004	0.005	0.007	0
C3	0.085	0.135	0.075	0.007	0.001		0	0	0.001	0.002	0.003	0
IC4	0.095	0.13	0.06	0.012	0.003	0		0	0	0	0.001	0
NC4	0.095	0.13	0.06	0.012	0.003	0	0		0	0	0.001	0
IC5	0.095	0.125	0.06	0.017	0.004	0.001	0	0		0	0	0
NC5	0.095	0.125	0.06	0.018	0.005	0.002	0	0	0		0	0
C6	0.1	0.125	0.05	0.024	0.007	0.003	0.001	0.001	0	0		0
PS-1	0	0	0	0.29535	0	0	0	0	0	0	0	

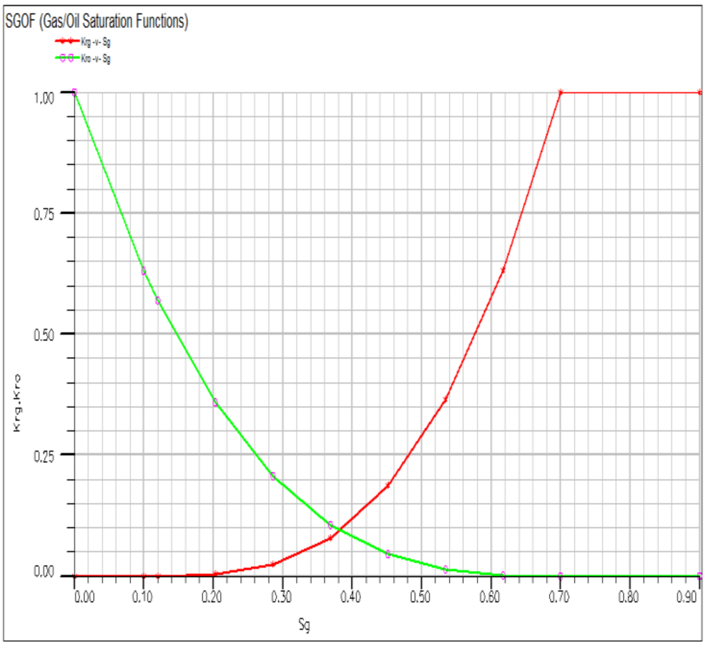

Fig: Gas/Oil Relative Permeability Curve

CVD LABORATORY OBSERVED DATA

S/NO	PRESSURE (PSIA)	RETROGRADE LIQUID VOLUME (%)
1	4191	0.00
2	3799	0.27
3	3099	1.10
4	2388	1.93
5	1610	2.65
6	978	2.61
7	524	2.25

CCE LABORATORY OBSERVED DATA

S/NO	PRES (PSIA)	REL. VOL. [V_{TOT}/V_{SAT}]	RET.LIQ (%)	DENSITY (LB/FT^3)	FORM. VOL. FACT. (FT^3/SCF)	Z-FACTOR
1	7062	0.769	-	19.29	0.00285	1.119
2	6559	0.793	-	18.728	0.00294	1.072
3	6056	0.822	-	18.042	0.00305	1.025
4	5553	0.855	-	17.355	0.00318	0.979
5	5051	0.899	-	16.543	0.00334	0.936
6	**4868 (RP)**	**0.915**	**-**	**16.23**	**0.00340**	**0.918**
7	4548	0.949	-	15.607	0.00353	0.890
8	**4191 (DP)**	**1.000**	**-**	**14.858**	**0.00371**	**0.862**
9	3543	1.118	0.57	-		
10	3041	1.247	1.22	-		
11	2741	1.360	1.60	-		

12	2440	1.512	2.08	-		
13	2139	1.718	2.38	-		
14	1837	1.987	2.71	-		
15	1536	2.391	2.84	-		
16	1215	2.896	2.79	-		

SYMBOLS AND ABBREVIATIONS

σ = Transmissibity Multiplier
Tc = Critical Temperature
Tct = Cricondentherm Temperature
Scc = Critical Condensate Saturation
PVT = Pressure Volume Temperature
API = American Petroleum Institute
GOR = Gas Oil Ratio
CGR = Condensate Gas Ratio
Mw = Molecular Weight
EOS = Equation of State
CCE = Constant Composition Expansion
CVD = Constant Volume Depletion
PR- Equation = Peng Robinson Equation
Kx = Permeability in X-direction
Ky = Permeability in Y-direction
Kz = Permeability in Z-direction

Xf = Fracture Halflength
Wf = Fracture Width
Kf = Fracture Permeability
FGPT = Field Gas Production Total
FGPR = Field Gas Production Rate
FLPT = Field Liquid Production Total
FLPR = Field Liquid Production Rate
FPR = Field Pressure