

COMPARATIVE STUDY OF VOLUMETRIC-DEPLETION AND GAS-INJECTION AT DEWPOINT PRESSURE TECHNIQUES FOR FLUIDS RECOVERY IN A GAS CONDENSATE RESERVOIR

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Abstract— volumetric depletion and gas-injection techniques were compared, gearing towards improving oil recovery factor in Gas-Condensate Reservoirs. The primary input data of the model were estimated values of total gas-condensate initially in place, recoverable gas and liquid volumes, permeability uniformity factor (E_K), displacement (E_D) and sweep (E_{SWP}) efficiencies in gas injection technique and Field plus laboratory test data of the field study. The condensable hydrocarbons recovery modelling using volumetric depletion and gas-injection methods were developed based on traditional simulation and can be used in condensable hydrocarbons recovery evaluations. The techniques for monitoring proper pressure maintenance were also developed using daily reservoir voidage out replacement by the injected gas volume. The estimated cumulative fluids (liquid and gas(oil)) recovery factor (ranges from 62 to 76% for 80% efficiencies) was higher and encouraging in gas injection method than in volumetric depletion method under the same conditions. Retrograde condensation was reduced because pressure was fairly maintained.

Index Terms— Condensate Recovery (Liquid/Gas), Volumetric-Depletion/Gas-Injection, Invasion-Factor, Molar Volume and Voidage-Out Replacement.

I. INTRODUCTION

Definition

Gas condensate (called Liquid or Distillates Oil) reservoirs are those which produce lighter coloured or colourless stock tank liquids with gravities above 45°API at gas-oil ratios in the range 3,000 to 100,000scf/bbl. The gas condensate production is predominately gas from which liquid (called oil or distillate) is condensed at the surface separator. [Allen, 1952]^[1]

Volumetric depletion is a pressure decline method from the dew-point pressure (P_d) to the reservoir abandonment pressure (P_a) while gas injection at dew-point pressure is a reservoir pressure maintenance agent used to control fluid recovery efficiency in a gas condensate reservoir. The other functions include: displacement of the condensate from the reservoir rocks, sweeping off the displaced fluids and

recovery of the swept fluids at a given time. The importance of the injected fluid is to invade and gain a replacing factor for improving the recovery in a gas condensate reservoir. [Udie, et al, 2014]^[2]

Liquids recovery in gas-condensate reservoirs is classified under low hydrocarbons fluids reservoirs (marginal oil field), because the techniques, quantity and expenses for liquid (oil) recovery in gas condensate reservoir are off the conventional recovery methods. The quantity of oil to be recovered using gas-injection depends on the quantity of the injected gas invasion and by volumetric depletion depends on the reservoir pressure. The gas invasion value depends on the void spaces in a reservoir to be replaced as a displacing agent. Gas injection gears towards an overall recovery factor of 0.46 to 0.48. The control or dependant parameters are rock permeability uniformity, displacement and injected-gas invasion/swept efficiencies. The recovery value is due to pressure maintenance, sweep efficiency and displacement by the injected gas vapour. If pressure is not enhanced (maintained), low recovery would establish itself through retrograde condensation in the gas-condensate reservoir. Gas re-cycling is only fairly good in a gas condensate with gas-cap, which is overlying by an oil-zone that is also overlain by an active water-drive. In this case the pressure is supported by the aquifer. In the absence of active water-drive, oil-zone can be depleted first, allowing the gas-cap to expand and sweep through the oil-zone, maximizing the recovery. This is because in the absence of active water-drive, the application of gas re-cycling would cause oil to zone into shrink gas-cap and/or the original oil- zone initially displaced by gas, resulting in low recovery. In order to predict the recovery value using this technique in gas-condensate reservoir, validation through field inspection is required. This involves the techniques for studying geological data, reservoir, rocks and fluids characterizations applications to aid history matching. [Williams, 1996]^[3]

II. SIMULATION & MODELLING IN GAS-CONDENSATE

The main objective of this work is to compare volumetric-depletion and gas-injection techniques for recovery fluids in gas condensate reservoirs. The specific objective is to develop mathematical models for studying and improving oil recovery factor in gas condensate reservoir, at reduced cost. The models gear towards maximizing pressure maintenance in any gas condensate reservoir and avoid retrograde condensation, which could result in low recovery. The simulator consists of a single well with injection properties and reservoir characterization. The effects of varying permeability uniformity and injected fluids invasion factors calculation are included in the model program.

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Single-phase flow is considered in single production and injection well system, which could be integrated into multiple production and injection wells system. The success of this model relies mainly on the following factors: Pressure maintenance in condensate reservoirs, invasion factor of the injected gas, permeability uniformity/efficiency of the reservoir and displacement efficiency of the gas used.

Standing, (1952)^[4] worked on the methods for adjusting equilibrium ratio. He used data from gas-condensate reservoir and applied to different compositions. In his work he gave step by step calculation.

Rodger et al, (1957)^[5] tried to improve standing's work and came out with the conclusion that there must be need to improve procedure in developing the equilibrium ratios for the heavier hydrocarbons. Their reason was that it would improve the overall accuracy of the calculation.

Jacoby et al (1958)^[6] worked on the effects of composition, temperature of the fluid phase and depletion performance of gas-condensate systems. They studied the phase behaviours of eight mixtures of separator-oil & gas from lean gas condensate reservoir at recombined ratio in the range of 2,000

to 25,000scf/bbl and temperature range of 100 to 200°F. They found out that the results would be useful in predicting the depletion performance of gas-condensate reservoirs in the absence of laboratory studies. They also found out that there would be a gradual change in the surface production performance from the volatile oil to wet (*rich*) gas-condensate reservoirs. They recommended that a laboratory examination would be necessary to distinguish between a dew-point and bubble point reservoir, especially in the range of 2,000 to 6,000scf/d gas-oil ratios.

Craft, and Hawkins, (1958)^[7] studied the laboratory test data and equilibrium ratio calculated results of a gas-condensate reservoir and compared with the actual field depletion performance history. That was a controlled experiment where 4,000cu.cm cell sample at the reservoir temperature and pressure was used. The cell was pressure depleted, so that only the gas phase passed through the miniature three-phase separator operated at optimum field pressure and temperature. The calculated performance was also obtained from equation involving equilibrium ratio, assuming differential process. They found out that the laboratory model study could adequately predict the gas condensate reservoir behaviour. The performance could as well be calculated from the composition of the initial reservoir fluids, provided representative equilibrium ratios are available. The

composition of differential process (constant volume, but changing composition) showed that only the gas would be produced and it could be removed from the liquid contact with the liquid phase in the reservoir while in the flash process (constant composition, but changing volume) showed that all the gas would remain in contact with the retrograde liquid. To this effect they recommended that, for it to be so the volume of the system must increase as the pressure declines.

Allens, and Roe, (1950)^[8] worked compared the predicted and the actual production histories of volumetric gas-condensate reservoir and found out that retrograde condensate reservoirs with initial gas-oil ratios, produced higher condensate at lower pressure than the theoretical calculations based on equilibrium ratios techniques only. They concluded that the difference in recovery was due to sampling error or retrograde condensed liquid of the heavier hydrocarbons near the wellbore, which might be immobile. They equally looked at the omission of nitrogen as a constituent of the gas-condensate from the calculations. They stated that a small amount of nitrogen was found in several samples, during the life of the reservoirs studied.

Craze, and Buckley, (1945)^[9] developed a material balance equation (MBE) for fluids recovery from water-drive reservoir where he assumed not appreciable decline in pressure. Their volumetric material balance equation was given as:
$$E_R = \frac{(1 - S_w)E_{gi} - S_{gr}E_g}{(1 - S_w)E_{gi}} \quad [2.1]$$

Thompson, et al, (1993)^[10] worked on gas condensate recovery using well test data

Eilerts, (1957)^[11], showed the distribution of gas-oil ratio and gas gravity (API) for 172 gas and gas condensate fields of 3-senerios. He found no correlation between the gas-oil ratio or the API of the tank liquid (oil) in these fields. Table 1 below shows his (Eilerts) experimental result of the gas-oil ratio in the 3-fields and table 2 shows the phase relation to tank oil gravity.

Berryman, (1957)^[12] pointed out that the classification of wells and reservoirs base entirely on production gas-oil ratio is inadequate. He recommended that proper classification reservoirs should be based on fluids composition, temperature and pressure.

Table 1 Phase Relation to Gas-Oil Ratios in 3 Fields

LGR GPM.SCF	GOR MScf/bbl	Fields			Total	% of Total
		A	B	C		
< 0.4	> 105	38	12	7	57	31.10
0.4 - 0.8	52.5 - 1.05	33	18	4	55	32.00
0.8 - 1.2	35.0 - 52.5	12	15	5	32	18.60
1.2 - 1.6	26.2 - 35.0	1	8	1	10	5.80
1.6 - 2.0	21.0 - 26.2	1	3	1	5	3.90
> 2.0	< 21.0	2	5	6	13	7.60
Total		87	61	24	172	100

Table 2 Phase Relation to Tank Oil Gravities in 3 Fields

LGR GPM.SCF	Gravity API	Fields			Total	% of Total
		A	B	C		
< 0.4	< 40	2	1	0	3	1.80
0.4 - 0.8	40 - 45	4	2	0	6	3.60
0.8 - 1.2	45 - 50	12	12	0	24	14.60
1.2 - 1.6	50 - 55	24	17	7	47	28.50
1.6 - 2.0	55 - 60	19	13	12	49	29.70
> 2.0	60 - 68	23	8	3	30	18.20
	> 68	3	1	2	6	3.60
Total		87	54	24	165	100

3. Materials and Methods

a. Materials

The materials used in this research were collected from Department of Petroleum Resources (DPR), Nigerian National Petroleum Corporation (NNPC): namely Oso Gas-Condensate production data, located in the Niger Delta geological formation. The materials collected covered the Field and Laboratory Test data. Table 3.1 shows history of the field and laboratory test data, table 3.2 shows the gas condensate fluid recovery data, table 3.3 shows the field and laboratory fluids test composition of the gas-condensate reservoir and table 3.4 shows field and laboratory test data (oil and gas) volume increments and the corresponding gas deviation factor.

Table 3.1 Field and Laboratory Test Data

Parameter	Symbol/Unit	Data
Initial Pressure	$P_i, psia$	6290
Dew-Point Pressure	$P_d, psia$	5412
Abandonment Pressure	$P_a, psia$	1400
Reservoir Temperature	$T_r, ^\circ F$	240
Connate Water Saturation	$S_{wi}, \%$	11
Average Porosity	$\phi, \%$	23
Daily Tank Oil	$V_{ot}, bbl/d$	220
Stock Tank Oil	$V_{ot}, stb/d$	24.06
Oil Gravity	$Y_o, ^\circ API$	46.8
Daily Separator Gas	$V_{gs}, Mscf$	2640
Separator Gas Gravity	Y_{gt}	0.716
Daily Tank Gas	$V_{gt}, Mscf$	144
Tank Gas Gravity	Y_g	1.30
Separator Temperature	$T_{sep}, ^\circ F$	83
Separator Pressure	$P_{sep}, psia$	25
Standard Temperature	$T_{sep}, ^\circ F$	60
Standard Pressure	$P_{sep}, psia$	15
Initial Cell Volume	$V_{cell}, cu. cm$	1000
Gas-Liquid Ratio	$GLR, scf/bbl$	7890
Molar Volume (constant)	$V_m, cu. ft/mole$	379.4
Separator Liquid Volume Factor	$B_{sl}, bbl/stb$	1.275
Molar of C_{7+} in initial Fluid	$M_{C_{7+}}, lb/lh.wt$	160
Sp.Gr of C_{7+} in Separator Liquid	$S_{gr}, \%$	0.718

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Residual Gas Saturation **Tables 3.2, 3.3& 3.4** **20**
Gas Composition/Liquid Volume -

Table 3.2 Gas Condensate Fluid from Laboratory Test Result

Condensate component	Gas component % Volume	Liquid Component % Volume	Molar Weight lb/mole
CO ₂	0.0017	0.0012	-
C ₁	0.8265	0.0992	16.04
C ₂	0.0630	0.0340	30.07
C ₃	0.0602	0.0893	44.49
iC ₄	0.0134	0.0419	58.12
nC ₄	0.0157	0.0679	58.12
iC ₅	0.0040	0.0441	72.15
nC ₅	0.0027	0.0420	72.15
C ₆	0.0015	0.0656	86.17
C ₇₊	0.0012	0.5069	165
Others	0.0101	0.0079	-
Total	1.00000	1.0000	-

Table 3.3 Field and Laboratory Fluid Composition of the Condensate at a Pressure

Pressure Psia	CO ₂	N ₂	C ₁	C ₂	C ₃	iC ₄	nC ₄	iC ₅	nC ₅	C ₆	C ₇₊
6290, P _i	-	-	-	-	-	-	-	-	-	-	-
5412, P _d	0.0169	0.0004	0.7286	0.0716	0.0779	0.0173	0.0236	0.0086	0.0065	0.0069	0.0417
4700	0.0830	0.0003	0.7345	0.0706	0.0752	0.0170	0.0230	0.0084	0.0053	0.0067	0.0377
4000	0.0179	0.0003	0.7393	0.0700	0.0750	0.0170	0.0228	0.0082	0.0060	0.0066	0.0361
3300	0.0176	0.0003	0.7442	0.0705	0.0748	0.0170	0.0226	0.0080	0.0058	0.0064	0.0328
2600	0.0174	0.0003	0.7531	0.0710	0.0749	0.0168	0.0222	0.0078	0.0055	0.0062	0.0248
1900	0.0172	0.0003	0.7604	0.0715	0.0750	0.0162	0.0220	0.0077	0.0054	0.0062	0.0181
1400, P _a	0.0174	0.0003	0.7632	0.0725	0.0760	0.0162	0.0218	0.0073	0.0052	0.0056	0.0145
Total											

Table 3.4 Field and Lab Test Data (Oil & Gas Volume Increment and Deviation Factor)

Pressure Psia	Gas Volume Recovery at	Gas Volume Recovery at	Retrograde Liquid in the Cell		Gas Deviation Z - Factor	Mol. Weight of MC ₇₊ lb/lb.wt
	T _i & P _{cell} V _g Cu.cm	Cell T _i & P _{cell} V _{cell} Cu.cm	Cell Volume V _{cell} = 1000 Cu.cm	Hydrocarbon Volume(HCV) % V _{cell}		
5412, P _d	N/A	0.00	0.000	0.00	1.007	160
4700	„	143.69	6.955	0.70	0.941	142
4000	„	324.09	15.710	1.57	0.886	138
3300	„	542.40	26.625	2.66	0.846	132
2600	„	806.90	39.625	3.96	0.821	127
1900	„	1127.11	54.729	5.47	0.816	123
1400, P _a	„	1359.06	65.836	6.58	0.820	119

b. Research Methodology

Procedures

Different techniques were used to estimate the fluids recovery factors. To achieve this, assumptions are made to enable us generate mathematical evaluation models and for good accuracy, the gas volume was collected based on the following procedures:

- i. Liquid recovery factors of the gas components were assumed, **25% C₄, 50% C₅, 75% C₆ and 100% C₇₊**
- ii. Total pay-zone area, A: assumed = a = 1 acre.foot. This can be integrated into the entire reservoir area.
- iii. Average pressure of the operating separators was estimated and used
- iv. The stock tank vapour and main high pressure separators
- v. The average gas gravity was estimated and used in this calculation
- vi. The gas deviation factor, Z was estimated from the combined gravity of oil and gas
- vii. The reservoir pressure (P_i = **6290psia**) was above the dew-point pressure (P_d = **5412psia**).

viii. The field and laboratory test estimated displacement efficiency, permeability uniformity factor and sweep efficiency of 80% each.

Input Parameters Estimation Models Using Tank Fluids Records

i. Initial oil and gas in place per acre-foot were estimated using initial field (history) and laboratory test data of the gas-condensate reservoir. **Mathematically:**

Gas: Liquid Ratio:

$$GLR = \frac{1000(V_{gs} + V_{gt})}{V_{ot}} = \frac{1000(2640+144)}{220} = 12.655scf/bbl$$

[3.1]

Average Fluids Gravity:

$$Y_{avg} = \frac{V_{gs} Y_{gs} + V_{gt} Y_{gt}}{V_{gs} + V_{gt}} = \frac{2640 \times 0.716 + 144 \times 1.30}{2640 + 144} = 0.7462$$

[3.2]

$$\text{Oil Gravity: } Y_o = \frac{141.5}{API+131.5} = \frac{141.5}{48.6-131.5} = 0.7857 \quad [3.3]$$

$$\text{Tank Oil Molecular Weight: } M_o = \frac{6084}{API - Y_o} = \frac{6084}{48.6 - 5.9} = 142.5lb.wt \quad [3.4]$$

Well Fluid Gravity:

$$Y_f = \frac{V_{gs} Y_{gs} + V_{gt} Y_{gt}}{R_g + \frac{132800 Y_o}{M_o}} = \frac{132800 \times 0.7462 + 2640 \times 0.7857}{7890 + \frac{132800 \times 0.7857}{142.5}} = 0.9234$$

[3.5]

Gas Deviation Factor:

$$Z_i = f(P_{pr}, T_{pr}) = f(P_i/P_{pc}, T_i/T_{pc}) \text{ Using AGA Table} \quad [3.6]$$

Where:

$$P_{pc} = f(Y_f) = f(0.9234) = 665psia \quad \& \quad P_t = 6290psia$$

implying that condensate

$$T_{pc} = f(Y_f) = f(0.9234) = 465^{\circ}R \quad \& \quad T_t = 700^{\circ}R \quad Z_i = f(9.5, 1.5) = 1.078$$

Bulk Reservoir:

$$G_b = \frac{43560 V_m P_t \phi (1 - S_{wt})}{Z_i N T_i} = \frac{43560 \times 379.4 \times 6290 \times 0.23 \times (1 - 0.11)}{1.078 \times 10.83 \times 700} = 2620Mscf/ac.ft$$

[3.7]

$$\text{Liquid (Oil): } V_L = \frac{G}{GLR} = \frac{2620000}{12655} = 207.03hhl/ac.ft \quad [3.8]$$

Condensate (Oil and Gas) Volume Fraction in moles:

$$\text{Gas Phase moles: } n_g = \frac{V_{gs} + V_{gt}}{V_{ot}} = \frac{2640+144}{220} = 12.65 \text{ moles} \quad [3.9]$$

$$\text{Liquid Phase moles: } n_o = \frac{350 Y_o}{M_o} = \frac{350 \times 0.7857}{142.5} = 1.93 \text{ moles} \quad [3.10]$$

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$$\% \text{ Gas-Condensate: } f_g = \frac{n_g}{n_g + n_c} = \frac{12.65}{12.65+1.93} = 86.76\% \quad [3.11]$$

Recoverable

Gas:

$$G_{p1} = C_g f_g = \left[\frac{13260 V_m P_i (1 - S_{wi})}{z_i R T_i} \right] \left[\frac{n_g}{n_g + n_c} \right] = 2620 * 0.8676 = 2400 \text{ Mscf/ac.}$$

[3.12]

Total Reservoir Voidage:

$$V_g = \frac{C Z_i T_i P_g}{F_i T_g} = \frac{2400 * 10^3 * 1.078 * 700 * 15}{0.290 * 520} = 8306 \text{ cu.ft/day}$$

[3.13]

Table 3.5 Condensate Fluid Composition in the Separator at the Operating Pressure

1	2	3	4	5	6	7	8
Condensate component	Gas component Mole	Liquid Component Mole	AGA Molar Weight lb/mole	(3) * (4) Separator Molar-wt lb/mole	Liquid Volume bbl/mole	(3) * (6) Separator Liquid-Wt bbl/mole	(2) * GLR Separator Gas-Oil Ratio Scf/bbl
CO ₂	0.0017	0.0012	-	-	-	-	0.3914
C ₁	0.8265	0.0992	16.04	1.5912	0.0540	0.0054	193.5663
C ₂	0.0630	0.0340	30.07	1.0200	0.1030	0.0035	14.7546
C ₃	0.0602	0.0893	44.49	3.9370	0.1524	0.0136	14.0988
iC ₄	0.0134	0.0419	58.12	2.4350	0.1991	0.0083	3.1383
nC ₄	0.0157	0.0679	58.12	3.9460	0.1990	0.0135	3.6769
iC ₅	0.0040	0.0441	72.15	3.1820	0.2471	0.0109	0.9368
nC ₅	0.0027	0.0420	72.15	3.0300	0.2470	0.0104	0.6323
C ₆	0.0015	0.0656	86.17	5.6530	0.2951	0.0194	0.3513
C ₇₊	0.0012	0.5069	185	93.7700	0.6336	0.3212	0.2810
Others	0.0101	0.0079	-	-	-	-	2.3654
Total	1.00000	1.0000	-	118.5744	-	0.4052	234.1961
9	10	11	12	13	14	15	
(3) * n _L	(8) + (9)	(10) ÷ n _c	From AGA Table Critical Pressure P _c , Psia	(11) * (12) Pseudo Critical Pressure P _{pc} , Psia	From AGA Table Critical Temperature T _c , °R	(11) * (14) Pseudo Critical Temperature T _{pc} , °R	
Liquid Fraction mole	Gas Mole	Condensate Total Fluid composition Mole					
0.0062	0.3944	0.0017	1070.2	1.82	547.5	0.93	
0.2292	193.5663	0.8197	673.1	552.00	343.2	281.32	
0.0785	14.7546	0.0627	708.3	44.41	549.9	34.48	
0.2063	14.3051	0.0604	617.4	37.35	666.0	40.29	
0.0968	3.1383	0.0136	529.1	7.25	734.6	10.06	
0.1568	3.6789	0.0162	550.1	8.91	765.7	12.40	
0.1019	0.9368	0.0044	484.0	2.13	829.6	3.65	
0.0970	0.6323	0.0031	490.0	1.52	846.2	2.65	
0.1515	0.3513	0.0021	440.0	0.92	914.2	1.92	
0.1709	0.2810	0.0061	395.9	2.41	972.45	5.93	
0.0148	2.3654	0.0100	3209.5	32.10	1165.2	11.77	
2.3099	236.5000	1.0000	-	690.82	-	405.44	

Source [Generated Using Table 3.2]: M C₇₊ = 160 lb/lb.wt & Sp.Gr C₇₊ = 0.718

Estimation Procedures:

Column - (1): Gas component of the laboratory test results

Column - (2): Mole composition of the gas-phase from the test result

Column - (3): Mole composition of the liquid-phase from the test result

Column - (4): Molar weight from AGA-Table (standard gas table), lb/mole

Column - (5): Molecular weight of the separator liquid: $\Sigma[(3) * (4)] = 118.5734 \text{ lb/mole}$ [3.14]

Column - (6): Fluids Liquid component: $n_L = \frac{(4) * M C_{7+} lb/bbl}{Sp.Gr C_{7+} * 350 lb/mole} = bbl/mole$ [3.15]

Column - (7): Separator liquid specific weight: $\Sigma[(3) * (6)] = 0.4062 lb/mole$ [3.16]

Column - (8): Recombination of Separator fluids for gas-liquid ratio (GLR)

$GLR = R_g = \Sigma \left[(2) * \frac{y_{gs}}{N_T B_{sep} V_m} \right] =$

234.1961 scf/bbl

[3.17]

Column - (9): Mole fraction of liquid component at separator pressure and 60°F (n_L)

$n_L = \frac{350 Y_0}{wt_{sep}} = \frac{350 Y_0}{\Sigma(5)} = 2.31 mole$ [3.18]

Column - (10): Fluids (liquid/ gas) mole: $n_f = \Sigma[(8) + (9)] = 236.6045 mole$ [3.19]

Column - (11): Total mole of the well fluids: $n = \Sigma[(10) + \Sigma(10)] = 1.00$ [3.20]

Column - (12): Critical pressure from AGA standard table: P_c [3.21]

Column - (13): Critical partial pressure: $P_{pc} = \Sigma[(11) * (12)] = 691.25 psia$ [3.22]

Partial reduced pressure: $P_{pr} = \frac{P_i}{P_{pc}} = \frac{6290}{691.25} = 9.10$ [3.23]

Column - (14): Critical Temperature: from AGA standard table: T_c [3.24]

Column - (15): Critical partial Temperature: $T_{pc} = \Sigma[(11) * (14)] = 405.64^\circ R$ [3.25]

Partial reduced Temperature: $T_{pr} = \frac{T_i}{T_{pc}} = \frac{700}{405.64} = 1.74$ [3.26]

Gas Compressibility factor:

$Z_i = f(P_{pr}, T_{pr}) =$

$f(9.10, 1.74) \text{ Using AGA Tables} = 1.078$

[3.27]

Initial total mole of fluids:

$n_i = \frac{P_i V_i}{Z_i R T_i} = \frac{43560 P_i \text{ @}}{Z_i R T_i} = \frac{43560 * 6290 * 0.23}{1.078 * 10.73 * 700} = 7783 mole/$

ac. ft

[3.28]

Gas Mole Fraction:

$\%n_g = \frac{R_g}{R_g + n_L} = \frac{n_g}{n_g + n_L} = \frac{n_f - n_L}{n_f} =$

$\frac{236.6045 - 2.31}{236.6045} = 99.02 \%$

[3.29]

Bulk

Reservoir

Rock:

$G_b = \frac{\%n_g n_i V_m}{1000} = \frac{0.9902 * 7783 * 379.4}{1000} =$

2900 Mscf/ac.ft

[3.30]

Daily

gas

condensate:

$G_{p2} = \frac{\text{Daily Separator Gas}}{\text{Gas Mole Fraction}} = \frac{2640}{0.9902} = 2700 Mscf/$

day

[3.31]

Total Oil in condensate: $N_2 = \frac{n_i(1 - n_g)}{n_2 B_{o1}} = \frac{7783 * 0.0098}{2.31 * 1.275 * 5.615} = 248 hhl/ac. ft$ [3.32]

Daily voidage at reservoir condition:

$V_g = \frac{S_p Z_1 T_1 P_2}{P_1 T_2} = \frac{2700 * 10^3 * 1.078 * 700 * 15}{6290 * 520} = 9344 cu.ft/$

day

[3.33]

ii. Volumetric Depletion Methods Using the Gas Condensate Reservoir Laboratory Test Data

Table 3.6 Condensate Recovery per acre foot

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1	2	3	4	5	6	7	8	9	10	11
Pressure Psia	ΔG_p Mscf	$\sum(\Delta G_p)$ 2454 Mscf	Residue Gas		Liquid Production		GLR $\sum \frac{\Delta G_p}{\Delta V_L}$ Scf/bbl	Recovery Factors		
			ΔG_r Mscf	$\sum(\Delta G_r)$ 2275 Mscf	ΔV_L bbl	$\sum(\Delta V_L)$ 220.7 bbl		(3) $\frac{G_p}{G_r}$ % ΔG_p	(5) $\frac{G_r}{G_r}$ % ΔG_r	(7) $\frac{V_L}{V_L}$ % ΔV_L
5412 P_d	0.0	0.0	0.0	0.0	0.0	0.0	11,119	0.0	0.0	0.0
4700	37.30	37.30	34.13	34.13	3.02	3.02	12,809	1.52	1.50	1.37
400	74.36	111.66	69.38	103.51	5.76	8.78	13,815	4.55	4.55	3.95
3300	109.45	221.11	102.61	206.12	7.24	16.02	15,728	9.01	9.06	7.26
2600	135.95	358.28	124.67	330.79	7.10	23.12	19,633	14.60	14.54	10.47
1900	129.58	487.86	145.60	476.39	7.09	30.21	24,458	19.88	20.94	13.69
1400 P_a	118.77	606.63	94.86	571.25	3.13	33.34	2833,34	24.72	25.11	15.06

Source [Generated using Tables 3.3 and 3.4]

At cell temp and pressure:

$$V_{HC} = V_g = V_i \phi (1 - S_{wi}) = 43560 \times 0.23 (1 - 0.11) = 8920 \text{ cu.ft/ac}$$

[3.34]

Bulk

$$G_b = \frac{V_m P_i V_{HC}}{1000 Z_i R T_i} = \frac{379.4 \times 6290 \times 8920}{1000 \times 1.070 \times 10.73 \times 700} = 2629 \text{ Mscf/ac.ft}$$

[3.35]

Recoverable Condensate:

$$G_p = \frac{V_m P_d V_{HC}}{1000 Z_i R T_i} = \frac{379.4 \times 5412 \times 8920}{1000 \times 1.078 \times 10.73 \times 700} = 2262 \text{ Mscf/ac.ft}$$

[3.36]

Moles of Liquid Condensate:

$$n_L = 25\% C_4 + 50\% C_5 + 75\% C_6 + 100 C_{7+} = 0.0609 \text{ moles}$$

[3.37]

Residual

$$G_r = G_p (1 - n_L) = 2262 \times (1 - 0.0609) = 2275 \text{ Mscf/ac.ft}$$

[3.38]

Recoverable

$$V_{L3} = \frac{\sum(w_i n_L)}{[25\% C_4 w_{T4} + 50\% C_5 w_{T5} + 75\% C_6 w_{T6} + 100 C_{7+} w_{T7+}]} = 207.2 \text{ bbl}$$

[3.39]

$$\text{Gas-Liquid Ratio: } GLR = R_g = \frac{G_p}{V_L} = \frac{2454 \times 10^3}{220.74} = 11,117.2 \text{ scf/bbl} \quad [3.40]$$

Daily Voidageout Replacement:

$$V_g = \frac{G_p Z_i P_i T_i}{P_i T_i} = \frac{2262 \times 1.078 \times 15 \times 700}{6290 \times 520} = 84.000 \text{ cu.ft/ac.ft}$$

[3.41]

Conventionally:

$$G_p = \frac{G_{p1} + G_{p2} + G_{p3}}{3} = 2454 \frac{\text{Mscf}}{\text{ac.ft}} \text{ and } V_L = \frac{V_{L1} + V_{L2} + V_{L3}}{3} = 220.74 \text{ bbl/ac.ft}$$

[3.42]

$$\text{Gas-Liquid Ratio: } GLR = \frac{11582 + 10887 + 11117}{3} = 11,195 \text{ Mscf/bbl} \quad [3.43]$$

Gas-Condensate:

Gas:

Liquid:

Column (2):

$$\Delta G_p = \frac{V_m F V_{gcel}}{1000 Z R T_i} = \frac{379.4 \times 4700 \times 143.69}{1000 \times 0.941 \times 10.73 \times 700} = 37.30 \text{ Mscf} \quad [3.43]$$

Column (3): $\Sigma(2) = \Sigma_{P_d}^{F_d} \Delta G_p = 37.30 + \dots +$ [3.44]

Column (4):

$$\Delta G_r = \Delta G_p [1 - n_L] = \Delta G_p [1 - (0.25C_4 + 0.5C_5 + 0.75C_6 + C_{7+})] = 34.13 \quad [3.45]$$

Column (5):

$$\Sigma(4) = \Delta G_p [1 - n_L] = \frac{V_m F V_{grel}}{1000 Z R T_i} [1 - (0.25C_4 + 0.5C_5 + 0.75C_6 + C_{7+})] \quad [3.46]$$

Column (6):

$$V_L = \frac{\Delta G_p}{42} [n_L * wt_i] = \frac{\Delta G_p}{42} [0.25 * 32C_4 + 0.5 * 36.32C_5 + 0.75 * 40.04C_6 + \frac{1000M C_{7+}}{V_m Z R T_i}] = \frac{\Delta G_p}{42} [8C_4 + 18.16C_5 + 30.03C_6 + \frac{1000M C_{7+}}{V_m Z R T_i}] = 2.83 \text{ bbl/ac.ft} \quad [3.47]$$

Column (7): $\Sigma(6) = \Sigma_{P_d}^{F_d} \Delta V_L = 2.83 + \dots +$ [3.48]

Column (8):

$$GLR = (4) \div (6) = \frac{\Delta G_r}{\Delta V_L} = \frac{\Delta G_p [1 - (0.25C_4 + 0.5C_5 + 0.75C_6 + C_{7+})]}{\frac{\Delta G_p}{42} [8C_4 + 16.16C_5 + 30.03C_6 + \frac{1000M C_{7+}}{V_m Z R T_i}]} = \frac{42 [1 - (0.25C_4 + 0.5C_5 + 0.75C_6 + C_{7+})]}{[8C_4 + 16.16C_5 + 30.03C_6 + \frac{1000M C_{7+}}{V_m Z R T_i}]} \quad \text{Note: } Wt_{C7+} = \frac{M C_{7+}}{\frac{V_m Z R T_i}{1000}} \quad [3.49]$$

Column (9): $E_{Gp} = \frac{\Delta G_p}{G_p} = \frac{(3)}{G_p} = 1.52$ [3.50]

Column (10): $E_{Gr} = \frac{\Delta G_r}{G_r} = \frac{(5)}{G_r} = 1.50$ [3.51]

Column (11): $E_{V_L} = \frac{\Delta V_L}{V_L} = \frac{(7)}{V_L} = 1.37$ [3.52]

Table 3.7 Cumulative Gas Condensate Depletion performance in the Reservoir

Pressure <i>Psia</i>	Deferential $\Delta P = P_d - P$ <i>Psia</i>	Fluids Recovery at a ΔP			Gas- Liquid Ratio <i>Scf/bbl</i>
		Gas %	Liquid %	Residual Gas % G_r	
5412 P_d	0.0	0.00	0.0	0.00	11,119
4700	712	1.50	1.37	1.52	12,809
4000	1412	4.55	3.95	4.55	13,815
3300	2112	9.06	7.26	9.01	15,728
2600	2812	14.54	10.47	14.60	19,633
1900	3512	20.94	13.69	19.68	24,458
1400 P_R	4012	25.11	15.06	24.72	28,725

Source [Generated using Tables 3.6]

iii. Gas Injection Techniques

Procedure

The principal factors considered in this gas injection or recycling methods are displacement efficiency stratification permeability and sweep efficiency of 80% each

$$[\text{Recovery Efficiency}] = [\text{Displacement Efficiency}] [\text{Permeability Efficiency}] [\text{Sweep Efficiency}]$$

$$E_R = E_D * E_K * E_{swp} = 0.8 * 0.8 * 0.8 = 0.51$$

2 [3.42]

Using the general material balance equation, MBE by *Eilert, (1957)*

$$[\text{Bulk Condensate in the Reservoir}] = [\text{Total Condensate Recovery}] - [\text{Total Water Enchroachment}] + [\text{Total Water Production}]$$

$$G_p B_{gi} = G (B_g - B_{gi}) + W_e + W_p \Rightarrow G = \frac{G_p B_g - 5.615 (W_e - W_p)}{E_g - B_{gi}}$$

[3.43]

In gas-recycling/injection, there is no water influx and water was not produced here, meaning that: $W_e = W_p = 0$,

substituting these (W_e and W_p) into eqn3.43 and rearranging, it generated eqn3.44

$$G_b = \frac{G_p B_g}{B_g - B_{gi}} = \frac{V_m}{3} \left[\frac{354.56 P_1 \phi (1 - S_{wi})}{Z_i R T_i} + \frac{n_g n_f}{1000} \right] = 2629 \text{ Mscf/ac.ft}$$

[3.44]

$$G = \frac{(G_{n1} - G_{n2} + G_{n3})}{n} = \frac{1}{3} \left[\frac{354560 V_m n_g P_1 \phi (1 - S_{wi})}{Z_i R T_i (n_g + n_d)} + \frac{V_g}{n_g} + \frac{35.56 V_m P_1 \phi (1 - S_{wi})}{Z_i R T_i} \right] = 2454 \text{ Mscf/ac.ft}$$

[3.44]

$$\%G_p = \%N_p = \frac{G E_R}{G_b} = \frac{G E_D E_K E_{swp}}{G_b} = \frac{51.2 * 2454}{2629} = 47.79 \%$$

[3.45]

Daily Voidage out Replacement:

$$V_g = \frac{G_p Z_1 P_1 T_1}{P_1 T_1} = \frac{2454 * 1078 * 15 * 700}{6290 * 520} = 84.924 \text{ cu.ft/ac.ft}$$

[3.46]

4. Results and Discussion

i. Results

Table 4.1 shows three methods theoretical/field, separator recombined and laboratory test data used to estimate initial gas-condensate parameters. Table 4.2 Shows Initial fluids estimated by different methods. Table 4.3 shows *evaluation models for recovery Values and factors estimations by Gas Injection*. Table 4.4 shows *evaluation models for recovery Values and factors estimations by volumetric depletion*. Table 4.5 shows the *comparison of depletion and gas-injection methods fluids recovery results*. Conventionally average values were considered to reduce percentage error.

Table 4.1 Gas Condensate evaluation models for Initial fluids Estimations

S/No.	Parameter	Gas-Condensate Evaluation Models
1.	Bulk Gas - Condensate	$G_b = \frac{V_m}{3} \left[\frac{354.56 P_1 \phi (1 - S_{wi})}{Z_i R T_i} + \frac{n_g n_f}{1000} \right] \text{ and } W_{t_{C7+}} = \frac{1000 M_{C7+}}{V_m Z R Y_{C7+}}$
2.	Initial Gas	

$$\begin{aligned}
 3. \quad & \text{Liquid (Oil)} \quad G = \frac{1}{3} \left[\frac{354560 V_m n_g P_i \phi (1 - S_{wi})}{Z_i R T_i (n_g + n_0)} + \frac{V_g}{n_g} + \frac{35.56 V_m P_d \phi (1 - S_{wi})}{Z_i R T_i} \right] \\
 4. \quad & \text{GLR and Voidage Out} \quad V_L = \frac{1}{3} \left[\frac{43.56 V_m V_{or} P_i \phi (1 - S_{wi})}{Z_i R T_i (V_{gs} + V_{gl})} + \frac{V_g}{n_g} + \left(8C_4 + 18.16C_5 + 30.03C_6 - \frac{1000 M C_{7+}}{V_m Z R Y_{C7+}} \right) \right] \\
 & \text{Gas-Liquid Ratio: } GLR = \frac{G}{V_L} \quad \text{and} \quad V_{out} = \frac{2.885 \cdot 10^{-4} G_p I_i T_i}{P_i}
 \end{aligned}$$

Table 4.2 Condensate Reservoir Initial Fluids Estimation Using Different Methods

Condensate	symbol	Theoretical Field Data	Separator Recombined	Laboratory Test Data	Average Data Considered
Bulk Volume	G_b	2620.00	2900	2629.00	2716.33
Recoverable	G	2400.00	2700	2262.00	2454.00
Residue Gas	G_r	2300.00	2671	2275.00	2415.33
Liquid Value	V_L	207.03	248.00	207.20	220.74
Gas-Liquid	GLR	11,593.00	10,887	10,980.00	11,153.33
Voidage Gas	V_g	8306.00	9344	8400.00	8683.33

Source [Generated Using Theoretical, Separator and Laboratory-Test Data]

Table 4.3 Evaluation models for recovery Values and factors estimations by Gas Injection

		Recovery Models Using Gas – Injection
11.	Bulk Gas – Condensate	$G_b = \frac{V_m}{3} \left[\frac{354.56 P_i \phi (1 - S_{wi})}{Z_i R T_i} + \frac{n_g n_f}{1000} \right]$
12.	Recoverable Gas Initially in Place	$G = \frac{1}{3} \left[\frac{354560 V_m n_g P_i \phi (1 - S_{wi})}{Z_i R T_i (n_g + n_0)} + \frac{V_g}{n_g} + \frac{35.56 V_m P_d \phi (1 - S_{wi})}{Z_i R T_i} \right]$
13.	Recovery Factors	$\% G_p = \% N_p = \frac{G E_R}{G_b} = \frac{G E_p E_R E_{swp}}{G_b}$ for both Oil and Gas

Table 4.4 Evaluation models for recovery Values and factors estimations by Volumetric Depletion

No.	Parameters	Volumetric Depletion Recovery Models
1.	Incremental Gas	$\Delta G_p = \frac{V_m P V_{gcel}}{1000 Z R T_i}$ at a given pressure
2.	Total Gas	$\sum \Delta G_p = \sum_{P_a}^{P_d} \left(\frac{V_m P V_{gcel}}{1000 Z R T_i} \right)$
3.	Sum-up	$\Delta G_r = \Delta G_p [1 - (0.25C_4 + 0.5C_5 + 0.75C_6 + C_{7+})]$
4.	Residue Gas Value	$\sum \Delta G_r = \sum_{P_a}^{P_d} \left(\frac{V_m P V_{gcel}}{1000 Z R T_i} [1 - (0.25C_4 + 0.5C_5 + 0.75C_6 + C_{7+})] \right)$
5.	Residue Gas Sum	$\Delta V_L = \frac{\Delta G_p}{42} [8C_4 + 18.16C_5 + 30.03C_6 + \frac{1000 M C_{7+}}{V_m Z R Y_{C7+}}]$
6.	Incremental Liquid	$\sum \Delta V_L = \sum_{P_a}^{P_d} \left(\frac{\Delta G_p}{42} [8C_4 + 18.16C_5 + 30.03C_6 + \frac{1000 M C_{7+}}{V_m Z R Y_{C7+}}] \right)$
7.	Liquid Recovered	$GLR = \frac{42 [1 - (0.25C_4 + 0.5C_5 + 0.75C_6 + C_{7+})]}{[8C_4 + 16.16C_5 + 30.03C_6 + \frac{1000 M C_{7+}}{V_m Z R Y_{C7+}}]}$
8.	Gas-Liquid Ratio	$\% G_p = \frac{\sum_{P_a}^{P_d} \Delta G_p}{G} = \frac{\sum_{P_a}^{P_d} \left(\frac{V_m P V_{gcel}}{1000 Z R T_i} \right)}{G}$
9.	Gas	$\% V_L = \frac{\sum_{P_a}^{P_d} \Delta V_L}{V_L} = \frac{\sum_{P_a}^{P_d} \left(\frac{\Delta G_p}{42} [8C_4 + 18.16C_5 + 30.03C_6 + \frac{1000 M C_{7+}}{V_m Z R Y_{C7+}}] \right)}{V_L}$

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Recovery Factor

$$\% G_r = \frac{\sum_{P_2}^{P_1} \Delta G_r}{G_r} = \frac{\sum_{P_2}^{P_1} \left(\frac{V_m P V_{gas}}{1000 Z R T_i} [1 - (0.25C_4 + 0.5C_5 + 0.75C_6 + C_{7+})] \right)}{G_r}$$

Liquid Recovery Factor

Percentage residue Gas

Source [Generated in Tables 3.7]

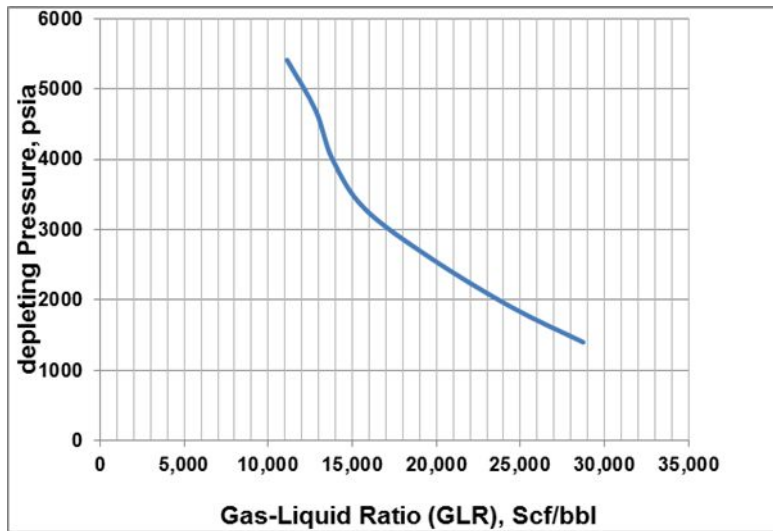
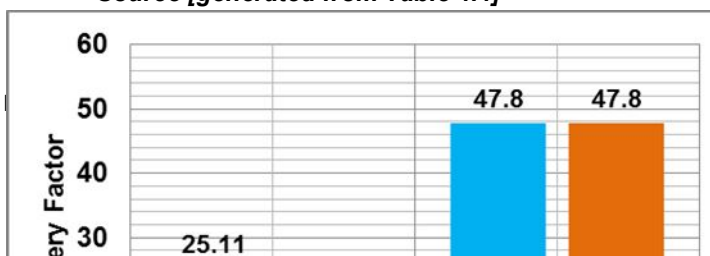


Fig 4.1 Estimated Gas-Liquid Ratio in Volumetric depletion Method

Table 4.5 Comparison of Depletion and Gas-Injection Methods Fluids Recovery Results

Recovery Method	Gas-Condensate <i>M scf/ac.ft</i>			Condensate Liquid <i>bbl/ac.ft</i>			Residue Gas <i>M scf/ac.ft</i>		
	<i>G</i>	<i>G_p</i>	<i>% G_r</i>	<i>N</i>	<i>N_p</i>	<i>% N_p</i>	<i>G</i>	<i>G_r</i>	<i>% G_r</i>
6290 - 1400 psia									
Volumetric Depletion	2454	606.61	24.72	220.14	33.34	15.06	2415.33	571.31	25.11
Gas-Injection	2454	173.0	47.80	220.14	105.2	47.80	2415.33	154.5	47.80

Source [generated from Table 4.4]



25.11	47.8
15.06	47.8



Fig 4.1 Estimated Recovery Factor of each Fluid in the Condensate

DISCUSSION

Table 4.1 shows models for initial condensate in place estimation. The models were generated using theoretical, separator and laboratory-test data and conventional average equations were considered in order to reduce percentage error. Table 4.2 Shows results of gas-condensate reservoir initial fluids estimation using theoretical, separator and Laboratory-test data. Here we observed that the bulk condensate initially in place would be best estimated using theoretical and Laboratory-test data only, because the separator data showed high percentage error, due to unaccounted for particulate and shrinkage facto of the separator fluids, in the volumetric Material Balance Equation (MBE) used. Table 4.3 Shows Evaluation models to estimate gas-condensate recovery values and factors in gas injection methods. Table 4.4 Evaluation models for recovery Values and factors estimations by Volumetric Depletion. Table 4.5 Compared recovery values and factors results in volumetric depletion and gas injection techniques. We found out that gas-condensate recovery factor (Gas = Oil = 47.80%) using gas injection as pressure maintenance was higher than using volumetric depletion method (Gas = 25.11 & Oil = 15.06%). Figure 4.1 is the graphical representation of the fluids recovery factor from the dew-point pressure (P_d) to the abandonment pressure (P_a). Figure 4.2 is a graphical representation of the GLR behavior with the deferential pressure.

CONCLUSION AND RECOMMENDATIONS

a. Conclusion

Gas injection technique has higher recovery factor (47.80 for both oil and gas) than volumetric depletion technique with recovery factors of 25.11% for gas and 15.06% for oil. This was possible because the reservoir pressure was fairly maintained through viodage out replacement using gas injection technique. Gas-injection or recycling would favour condensate recovery with good injected gas invasion factor, displacement and sweep efficiencies. The disadvantages in gas injection technique include: High cost of re-cycling, deferred income from the sale of gas, additional cost since more wells, compressors and distribution systems would be needed in the injection and liquid recovery plants. The volumetric depletion from initial or dew-point pressure to

abandonment had lower recovery factor, because the reservoir pressure was not maintained. Normally when pressure is not maintained, retrograde condensation of heavier hydrocarbons establishes itself as the flowing fluid-stream approaches the wellbore. Retrograde liquid is less mobile due to high viscosity and gravity effects. Improving recovery factor in a gas-condensate reservoir depends on the operator's techniques used.

b. Recommendations

- Gas injection is recommended here since it has higher recovery factor than volumetric-depletion method.
- Particulates (water and sand particles in the samples) and acid gases should not be omitted from the compositional analysis, this insures correct recovery history.
- Gas condensate reservoir performances prediction should be backed-up with the available laboratory data. This improves initial reserve values estimation.

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