

Economic Evaluation of Hydraulic Fracturing in a Gas Condensate Reservoir Operating below Dewpoint

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How to cite this paper: Kerunwa, A., Ariche, P.O. and Izuwa, N.C. (2020) Economic Evaluation of Hydraulic Fracturing in a Gas Condensate Reservoir Operating below Dewpoint. *Open Journal of Yangtze Gas and Oil*, 5, 73-86.

<https://doi.org/10.4236/ojogas.2020.53007>

Received: April 6, 2020

Accepted: May 11, 2020

Published: May 14, 2020

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Abstract

Hydraulic fracturing is among the approaches used to optimize production from a gas condensate reservoir. A detailed economic analysis is required to evaluate the profitability and feasibility of hydraulic fracturing as an optimization option in a gas condensate reservoir operating below dewpoint. The objective of this research is to evaluate the economic benefits derivable from the use of hydraulic fracturing to improve gas and liquid recovery from a gas condensate reservoir operating below dewpoint. This research considers the use of four profit indicators to ascertain the profitability of hydraulic fracturing in a gas condensate reservoir operating below dewpoint by increasing the fracture halflength, fracture width and fracture permeability. The production data of the reservoir was obtained and the economic calculations done on excel spreadsheet and plots generated. The four profit indicators considered in the research are Net Present Value, Payout, Discounted Cash Flow Rate of Return and Profit per Dollar Invested. The economic justification was done by carrying out a comparative economic analysis from the result obtained when the reservoir of study was unfractured with that obtained when the reservoir was fractured at various fracture parameters. The economic analysis was done considering a royalty and tax rate of 18.5% and 30% respectively and a gas price of \$2/MSCF and condensate price of \$30/bbl. This is done so as to find out if the additional cost of hydraulic fracturing can be offset by the recovery from the reservoir when its pressure declined below dewpoint. The result obtained showed that the additional recovery due to hydraulic fracturing by increasing the fracture halflength, fracture width and fracture permeability was not enough to justify the application of hydraulic fracturing when the reservoir pressure declined below dewpoint.

Keywords

Economic Evaluation, Fracture Halflength, Proppants, Profit Indicators,

1. Introduction

Gas condensate reservoir is among the types of reservoirs that we have and as such it represents a major source of hydrocarbon. Gas condensate reservoir is 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 cricondenterm (T_{Ct}) on the pressure-temperature diagram [1]. Gas condensate reservoir is of economic importance as a result of the additional liquid produced when the reservoir pressure drops below dewpoint. At pressures below dewpoint pressure of the reservoir, liquid drops out of the gas phase in a process known as condensate banking. This dropped out liquid plugs the pore spaces thereby limiting the flow of gas through the porous medium. One of the methods used to improve recovery from a gas condensate reservoir is hydraulic fracturing. A well's ability to produce hydrocarbons or receive fluids that are injected is limited by the natural permeability of the reservoir and then changes in near-wellbore that results from drilling and/or other operations. Hydraulic fracturing, otherwise called hydraulic stimulation, causes an improvement in the flow of hydrocarbon by the creation of fractures in the formation connecting the wellbore and reservoir. A hydraulic fracture involves inducement of fracture through pressure by the injection of fluid into a target reservoir rock formation. Fluid is then pumped into the rock formation at high pressures that are far above the fracture pressure—the rocks breaking pressure [2]. Hydraulic Fracturing involves the injection of a large volume of frac fluids into the well under high pressure to fracture the reservoir rock. It involves pumping fluid into a wellbore faster than the escape of the fluid into the formation causing enormous rise in pressure, thereby leading to the creation of cracks in the deep formation-rocks through which brine, natural gas and crude oil will easily flow through [3]. The fracturing fluid used is primarily water that contains sand or some other proppants that are suspended with the help of a thickening agent. Hydraulic fracturing is mostly suited to wells in low and moderately permeability reservoirs that do not provide commercial production rates [4]. Hydraulic fracturing performs the primary objective of increasing the well contact area by increasing the wellbore radius and enhancing the productivity of the well by achieving linear flow instead of radial flow when fluid is going inside the wellbore [5]. However, hydraulic fracturing does not eliminate condensate accumulation in areas where the pressure in the formation is below dewpoint. It only delays the time of reaching the dew point pressure but does not completely prevent condensate blockage [6]. In this work, Economic Analysis of hydraulic fracturing was carried out to ascertain if hydraulic fracturing will be a better alternative to optimize liquid and gas recovery from a gas condensate reservoir operating below dewpoint due to liquid blockage effect. Various profit indicators

such as Net Present Value, Discounted Cash Flow Rate of Return, Payout Time and Profit per Dollar Invested were considered to ascertain the profitability of Hydraulic Fracturing technique in improving recovery from gas condensate reservoir operating below dewpoint.

2. 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 type of reservoir. A brief insight to some of the literature reviewed during the research is outlined below:

Andrey *et al.*, (2016) [7] carried out a research on economic analysis and optimization of fracture-stimulated wells in condensate reservoirs. In their study, they built and validated a numerical model for production decline calculation in condensate reservoir with transient analysis of three phase pressure distribution. The model developed has been used for the sensitivity analysis study of reservoir productivity involving spacing and fracture size changes and the permeability of condensate reservoirs which was fractured, thereby accounting for the properties of the reservoir as well as multiphase flows of such reservoir. Ignatyev *et al.*, (2011) [8] evaluated horizontal wells' hydraulic fracturing as an approach for effectively developing gas/condensate Arctic region fields. They established that horizontal wells' productivity with fractures was much greater than horizontal well's production without fractures nine times and thrice bigger than fractured vertical wells. They posited that in horizontal wells multistage type of fracturing lowered the losses occurring in condensate together with the drawdown then lifted up the PI of the well. Zeeshan *et al.*, (2016) [5] utilized a novel approach to optimize the parameters of hydraulic fracturing in gas condensate reservoirs. They highlighted the effect of skin damage due fracture face associated with the length and width of hydraulic fractures and 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. Sheraz *et al.*, (2016) [9] carried out a research on recovery enhancement in a gas condensate reservoir with low permeability through the technologies of hydraulic fracturing and EOR. They investigated the impact of coupling and inertia on hydraulically fractured wells, using 3D reservoir simulation on real time data. They presented a comprehensive strategy that detailed all the factors having maximum influence on ultimate recovery and verified the operational and economic aspects of such technologies, to increase the overall gas and condensate production from the field. Ravari *et al.*, (2005) [10] conducted a research on gas condensate damage that occurred in hydraulically fractured wells. In their study, they used compositional reservoir simulation to model production for three scenarios; all having low permeability with hydraulic fractures. The simulation results showed that lower wellbore pressures yielded higher production rates which were in agreement with field results. Even though they observed damage to condensate well

below the dewpoint, there was no case that showed reduced pressure at borehole led to extremely poor well performance. Even for the case of very rich gas condensate, the optimum conditions correspond to the lowest Pwf. Mogan *et al.*, (2006) [11] carried out a research on non-darcy flow effect on the productivity of a gas condensate well that was hydraulically fractured. They utilized two level local grid refinements to show that very small grid blocks corresponding to actual fracture width could be simulated. An actual fracture width was used to accurately model non-darcy flow. The results of the simulation show that there was overestimation of productivity improvements by a high factor of three if non-darcy flow is neglected. Factors different from the ones mentioned earlier that control the improvement of productivity like well flow rates, fracture conductivity, fracture length as well as the parameters of reservoir were also studied.

3. Methodology

In the bid to present a detailed economic evaluation of hydraulic fracturing in gas condensate reservoir operating below dewpoint, the research adopts three approaches:

- 1) Obtaining hydraulic fracturing parameter of the gas condensate reservoir under study
- 2) Obtaining the production and input data of the gas condensate reservoir of study.
- 3) Using profit indicators to carry out economic calculations to ascertain the profitability of the hydraulic fracturing technique.

3.1. Hydraulic Fracturing Parameter

Hydraulic fracturing was used as a well stimulation approach in order to optimize production from the reservoir of study when the reservoir pressure dropped below dewpoint as a result of liquid dropout. The hydraulic fracturing job was done at various fracture parameters. The fracture parameters considered are fracture halflength (X_f), fracture width (W_f) and fracture permeability (K_f). During the hydraulic fracturing job three cases were considered. These are:

CASE 1: $X_f = 1000$ ft, $W_f = 0.03$ ft, $K_f = 1000$ md.

CASE 2: $X_f = 2000$ ft, $W_f = 0.06$ ft, $K_f = 2000$ md.

CASE 3: $X_f = 3000$ ft, $W_f = 0.1$ ft, $K_f = 3000$ md.

3.2. Production and Input Data

The gas and liquid production data was obtained from the reservoir when it is unfractured and when it is fractured at various fracture halflength, fracture width and fracture permeability. This is done so as to evaluate the economic viability of the hydraulic fracturing job. In both cases no form of pressure maintenance was done to the reservoir. Production of the reservoir fluid was done using the reservoir energy. The production data were collected for a period of ten (10) years. The reservoir fluid was produced at a rate of 40,000 MSCF/D. Other input data such as investment cost, operating cost, royalties and taxes

payable for these projects were obtained and used in the analysis. The production data are shown in **Table 1** and **Table 2** below while the CAPEX for the different cases considered are shown in **Table 3**.

Table 1. The Cumulative Liquid Production for the different cases considered.

YEAR	FLPT (STB) FOR UNFRACTURED CASE	FLPT (STB) FOR XF = 1000 FT, WF = 0.03 FT, KF = 1000 MD	FLPT (STB) FOR XF = 2000 FT, WF = 0.06 FT, KF = 2000 FT	FLPT (STB) FOR XF = 3000 FT, WF = 0.1 FT, KF = 3000 MD
1	253,192.86	253,192.86	253,192.86	253,192.86
2	484,541.72	490,540.25	490,551.19	490,640.75
3	666,909.06	684,208.69	684,240.88	684,458.75
4	800,764.13	833,562.5	833,623.75	833,988.5
5	889,688.25	940,845.69	940,941.31	941,466.5
6	939,643.56	1,010,093.9	1,010,226.7	1,010,919.3
7	957,482.44	1,046,489.3	1,046,659.1	1,047,517.9
8	957,802.75	1,055,935.5	1,056,136.6	1,057,138.6
9	957,802.75	1,055,935.5	1,056,136.6	1,057,138.6
10	957,802.75	1,055,935.5	1,056,136.6	1,057,138.6

Table 2. The Cumulative Gas Production (FGPT) for the different cases considered.

YEAR	FGPT(MSCF) FOR UNFRACTURED CASE	FGPT (MSCF) FOR XF = 1000 FT, WF = 0.03 FT, KF = 1000 MD	FGPT (MSCF) FOR XF = 2000 FT, WF = 0.06 FT, KF = 2000 FT	FGPT (MSCF) FOR XF = 3000 FT, WF = 0.1 FT, KF = 3000 MD
1	14,400,000	14,400,000	14,400,000	14,400,000
2	28,800,000	28,800,000	28,800,000	28,800,000
3	43,200,000	43,200,000	43,200,000	43,200,000
4	57,600,000	57,600,000	57,600,000	57,600,000
5	72,000,000	72,000,000	72,000,000	72,000,000
6	86,400,000	86,400,000	86,400,000	86,400,000
7	1.008E+8	1.008E+8	1.008E+8	1.008E+8
8	1.152E+8	1.152E+8	1.152E+8	1.152E+8
9	1.282E+8	1.296E+8	1.296E+8	1.296E+8
10	1.294E+8	1.420E+8	1.421E+8	1.422E+8

Table 3. Total CAPEX for the different cases considered.

S/NO	CASES CONSIDERED	TOTAL CAPEX (\$MILLION)
1.	Natural Depletion without hydraulic fracture	35.5
2.	Depletion with Hydraulic Fracture at Xf = 1000 ft, Wf = 0.03 ft and Kf = 1000 md	38.4
3.	Depletion with Hydraulic Fracture at Xf = 2000 ft, Wf = 0.06 ft and Kf = 2000 md	38.9
4.	Depletion with Hydraulic Fracture at Xf = 3000 ft, Wf = 0.1 ft and Kf = 3000 md	39.4

3.3. Profit Indicators Utilized to Carry out Economic Calculations

In the bid to have a clear understanding of the objective of this paper, the profit indicators considered are presented below:

3.3.1. Net Present Value

Net present value commonly abbreviated as NPV is the commonly used method for considering the time value of money when making investment decisions [12]. It is a popular decision criterion. NPV and PV are used interchangeably. The “Net” is used to distinguish that the investment and/or operating costs have been deducted from net cash flow (NCF) [13] [14]. It helps to compare the value of a certain amount of money today to the value of the future amount of that same money and vice versa, taking into consideration inflation and returns. For instance, if one is given an investment opportunity, the NPV can be used as a tool for the evaluation of the profitability of a venture and also to make decisions with respect to capital budgeting [15]. NPV is thus calculated as follows:

$$N = F \left[\frac{1}{(1+i)^t} \right] \quad (1)$$

where:

N = Net present value, F = Future Value

$$\left[\frac{1}{(1+i)^t} \right] = \text{Discount Factor}$$

Positive NPV shows that the investment opportunity is viable; therefore any investment opportunities with negative NPVs should be rejected [13].

3.3.2. Payout Time

Payout time commonly abbreviated as PO is an indicator of the rate at which cash flows are generated early in the project [13]. This address the concern, “The time it takes to get our investment recovered” It says nothing about the amount or rate of earnings after payout time. Payout time can also be called payback period. This determines the number of years that will have to elapse in order for the invested capital to be recovered out of the net incoming cashflow. It is the time at which cumulative NCR becomes zero. This method is mostly used by industry for assessing the economic desirability of an investment. The payback may or may not be with interest. The payout is calculated using the interpolation below:

$$\begin{aligned} & (\text{PO} - \text{IP}) / (\text{FP} - \text{IP}) \\ & = (0 - \text{CUM NCR at IP}) / (\text{CUM NCR at FP} - \text{CUM NCR at IP}) \end{aligned}$$

where: PO = payout, IP = initial point, FP = final point, CUM NCR = cumulative net cash recovery. In this equation, PO is made the subject of the equation.

When comparing the payback period for investment proposals, it is usually more desirable to have a short payback period than a longer one. This is because a short payback period indicates that the investment provides revenues early in its life, which is sufficient to cover the initial outlay [12].

3.3.3. Discounted Cash Flow Rate of Return

This is the discount interest rate such that NPV equals zero. It is among the widely used profit indicators in recent years. Discounted Cash Flow - Rate of

Return is commonly abbreviated as DCF-ROR [13]. This is the interest rate which causes the equivalent receipts of a cash flow to equal the equivalent disbursements of the cash flow. It is also defined as the interest rate that reduces the worth of a series of receipt and disbursements to zero [12]. Calculating DCF-ROR involves an iterative (trial and error) process. This profit indicator is also known by some other names such as: Internal rate of return, Investors method, receipts versus disbursement method.

3.3.4. Profit per Dollar Invested (P/\$)

This is another important profit indicator used to evaluate the profitability of a project. It is a ratio of Cumulative NCR to CAPEX. Mathematically, it is calculated as [13] [14]:

$$P/\$ = \frac{\text{Cumm.NCR}}{\text{CAPEX}} \quad (3)$$

4. Reservoir Overview

The reservoir contains a lean gas condensate fluid with an API of 45.7°, a GOR of 56.9 MSCF/STB and a Condensate to Gas Ratio of 17.6 STB/MMSCF. The reservoir fluid was produced using a single vertical well model located at the centre of the square drainage area with an I.D of 0.5 ft as the base case and a fractured single well model at various fracture halflength, fracture width and fracture permeability as the second case. The reservoir was initially above dewpoint with initial reservoir pressure of 4868 psia but declined below dewpoint pressure of 4191 psia due to production.

5. Results and Discussions

To analyse the profitability of hydraulic fracturing, economic analysis was performed to ascertain if the execution of the project will be economically viable. It is usually good to proceed with projects if the profitability calculations are in line with the following decision rules [14].

5.1. Net Present Value (NPV)

From **Table 4** below, the NPV at an expected rate of return of 10% for the unfractured reservoir which is the sum of all the present values in that column is equal to \$445.3 Million. From **Table 5**, fracturing the reservoir at $X_f = 1000$ ft, $W_f = 0.03$ ft and $K_f = 1000$ md generated an NPV of \$455.5 Million at 10% discount rate. This increase in NPV at this fracture parameter as seen in **Figure 1** below is due to the increase in cumulative liquid recovery as seen in **Table 1** above. This shows that the additional liquid recovered at the expiration of the production period was able to offset the additional cost of hydraulic fracturing. From **Table 6**, increasing the fracture parameters to $X_f = 2000$ ft, $W_f = 0.06$ ft and $K_f = 2000$ md gave an NPV of \$455 Million at 10% discount rate. **Table 7** shows that further increase in fracture parameters to $X_f = 3000$ ft, $W_f = 0.1$ ft and $K_f = 3000$ md yielded an NPV of \$453.5 Million dollars at 10% discount rate

after 10 years of production. The decrease in NPV at these fracture parameters as shown in **Table 8** clearly indicates that the additional liquid recovered at the end of the production period was not enough to compensate for the additional cost of hydraulic fracturing.

5.2. Pay out (P.O)

Pay Out is the point where Cumulative NCR changes to positive. From **Table 4** for natural depletion without hydraulic fracture, the P.O lies between 1st and 2nd year that is, P.O is 1.52 yrs. From **Table 5**, the P.O lies between 1st and 2nd year, fracturing the reservoir at $X_f = 1000$ ft, $W_f = 0.03$ ft and $K_f = 1000$ md generated a P.O of 1.59 yrs. From **Table 6**, the P.O lies between 1st and 2nd year, increasing the fracture parameters at $X_f = 2000$ ft, $W_f = 0.06$ ft and $K_f = 2000$ md gave a P.O of 1.6 yrs. From **Table 7**, the P.O lies between 1st and 2nd year, extending the fracture parameters at $X_f = 3000$ ft, $W_f = 0.1$ ft and $K_f = 3000$ md gave a P.O of 1.62 yrs. The increase in P.O as seen in **Table 8** for the hydraulic fractured reservoir is due to the additional cost incurred by the hydraulic fracturing job which delayed the payout time.

5.3. Profit per Dollar Invested

From **Table 4** the Cumulative Net Cash Recovery (CNCR) for Natural Depletion without fracture after 10 years is \$865.7 Million and the CAPEX is \$35.5 Million, the profit per dollar invested is \$24.4. From **Table 5**, fracturing the reservoir at $X_f = 1000$ ft, $W_f = 0.03$ ft and $K_f = 1000$ md gave a profit per dollar invested of \$23.2 after 10 yrs of production. From **Table 6**, increasing the fracture parameters at $X_f = 2000$ ft, $W_f = 0.06$ ft and $K_f = 2000$ md yielded a profit per dollar invested of \$22.9 after 10 yrs of production. From **Table 7**, further increase of fracture parameters at $X_f = 3000$ ft, $W_f = 0.1$ ft and $K_f = 3000$ md yielded a profit per dollar invested of \$22.6 after 10 yrs of production. The decrease in profit per dollar invested for the fractured cases as seen in **Table 8** is due to the additional cost of hydraulic fracturing which could not be compensated by the additional liquid recovered.

5.4. Discounted Cash Flow-Rate of Return (DCF-ROR)

DCF-ROR was obtained from the plot of NPV against interest rate as shown in **Figures 1-4**. It is the interest rate that discounts NPV to zero. From **Figure 1** and **Table 8**, DCF-ROR for Natural Depletion without fracture is 88%. From **Table 5** fracturing the reservoir at $X_f = 1000$ ft, $W_f = 0.03$ ft and $K_f = 1000$ md gave a DCF-ROR of 92% as shown in **Figure 2** and **Table 8**. This increase in DCF-ROR as seen in **Table 8** and **Figure 1** is due to the increased liquid recovery witnessed at the fracture parameter. **Table 6** shows that increasing the fracture parameters to $X_f = 2000$ ft, $W_f = 0.06$ ft and $K_f = 2000$ md gave a DCF-ROR of 87% as shown in **Figure 3**. From **Table 7**, further increase in parameters at $X_f = 3000$ ft, $W_f = 0.1$ ft and $K_f = 3000$ md yielded a DCF-ROR of 88% as seen in **Figure 4** and **Table 8**. The decrease in DCF-ROR at these fracture parameters

clearly shows that the additional liquid recovered was not able to offset the additional cost of hydraulic fracturing.

Table 4. Cash Flows for Natural Depletion without Hydraulic Fracture.

Time(Yrs)	0	1	2	3	4	5	6	7	8	9	10	NPV
Gp(BSCF)	0	14.4	28.8	43.2	57.6	72	86.4	100.8	115.2	128.2	129.4	
Np(MMSTB)	0	0.253	0.49	0.67	0.80	0.89	0.940	0.957	0.958	0.96	0.958	
CAPEX(\$MM)	-35.5	0	0	0	0	0	0	0	0	0	0	
OPEX(\$MM)	0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	
Gross Rev(\$MM)	0	36.4	72	106	139	171	201	230	259	285	287	
NCR(\$MM) b/4 Royalty and Tax	-35.5	33.4	69	103	136	168	198	227	256	282	284	
Royalty + Tax (\$MM) 48.5% of NCR	0	16	33.5	50	66	81.5	96	110.1	124.2	136.8	137.7	
NCR (\$MM) after Royalty and Tax	0	17	35.5	53	70	86.5	102	116.9	131.8	145.2	146.3	
CUM. NCR (\$MM)	-35.5	-18.3	17	70	140	226.5	328.5	445.4	577.2	722.4	865.7	
PV @10%	-35.5	15.5	29.4	39.9	47.8	53.7	57.6	60	61.5	61.6	56.4	445.8
PV @ 30%	-35.5	13.1	21	24.1	24.5	23.3	21.1	18.6	16.2	13.7	10.6	150.8
PV @ 50%	-35.5	11.3	15.8	15.7	13.8	11.4	9	6.9	5.2	3.8	2.5	59.9
PV @ 80%	-35.5	9.4	11	9.1	6.7	4.6	3	1.9	1.2	0.7	0.4	12.5
PV @ 100%	-35.5	8.5	8.88	6.6	4	2.7	1.59	0.9	0.5	0.29	0.1	-1.3
PV @ 150%	-35.5	6.8	5.7	3.4	1.79	0.88	0.4	0.19	0.09	0.04	0.01	-16.2

Table 5. Cash Flows for Fractured Case (At $X_f = 1000$ ft, $W_f = 0.03$ ft, $K_f = 1000$ md).

Time(Yrs)	0	1	2	3	4	5	6	7	8	9	10	NPV
Gp(BSCF)	0	14.4	28.8	43.2	57.6	72	86.4	100.8	115.2	129.6	142	
Np(MMSTB)	0	0.23	0.49	0.684	0.834	0.941	1.01	1.046	1.056	1.056	1.056	
CAPEX(\$MM)	-38.4	0	0	0	0	0	0	0	0	0	0	
OPEX(\$MM)	0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	
Gross Rev(\$MM)	0	36.4	72.3	106.9	140.2	172.2	203.1	233	262.1	290.9	315.7	
NCR(\$MM) b/4 Royalty and Tax	-38.4	33.4	69.3	103.9	137.2	169.2	200.1	230	259.1	287.9	312.7	
Royalty + Tax (\$MM) 48.5% of NCR	0	16.2	33.6	50.4	66.5	82.1	97.05	111.6	125.7	139.6	151.7	
NCR (\$MM) after Royalty and Tax	0	17.2	35.7	53.5	70.7	87.1	103.1	118.5	133.4	148.3	161	
CUM. NCR (\$MM)	-38.4	-21.2	14.5	68	138.7	225.8	328.9	447.4	580.8	729.1	890.1	
PV @10%	-38.4	15.6	29.5	40.2	48.3	54.1	58.2	60.8	62.2	62.9	62.1	455.5
PV @ 30%	-38.4	13.2	21.1	24.4	24.7	23.5	21.4	18.9	16.4	14	11.7	150.8
PV @ 50%	-38.4	11.5	15.9	15.9	14	11.5	9.05	6.9	5.2	3.9	2.8	58.1
PV @ 80%	-38.4	9.6	11	9.2	6.7	4.6	3	1.9	1.2	0.7	0.5	10.1
PV @ 100%	-38.4	8.6	8.9	6.7	4.4	2.7	1.6	0.9	0.5	0.3	0.2	-3.54
PV @ 150%	-38.4	6.9	5.7	3.4	1.8	0.9	0.4	0.2	0.09	0.04	0.02	-18.9

Table 6. Cash Flows for Fractured Case (At $X_f = 2000$ ft, $W_f = 0.06$ ft, $K_f = 2000$ md).

Time(Yrs)	0	1	2	3	4	5	6	7	8	9	10	NPV
Gp(BSCF)	0	14.4	28.8	43.2	57.6	72	86.4	100.8	115.2	129.6	142.1	
Np(MMSTB)	0	0.253	0.49	0.684	0.834	0.941	1.01	1.047	1.056	1.056	1.056	
CAPEX(\$MM)	-38.9		0	0	0	0	0	0	0	0	0	
OPEX(\$MM)	0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	
Gross Rev (\$MM)	0	36.4	72.3	106.9	140.2	172.2	203.1	233	262.1	290.9	315.9	
NCR(\$MM) b/4 Royalty and Tax	-38.9	33.4	69.3	103.9	137.2	169.2	200.1	230	259.1	287.9	312.9	
Royalty + Tax (\$MM) 48.5% of NCR	0	16.2	34	50.4	66.5	82.1	97.0	111.6	125.7	139.6	151.8	
NCR (\$MM) after Royalty and Tax	0	17.2	35.7	53.5	70.7	87.1	103.1	118.5	133.4	148.3	161.1	
CUM. NCR (\$MM)	-38.9	-21.7	14	67.5	138.2	225.3	328.4	446.9	580.3	728.6	889.7	
PV @10%	-38.9	15.6	29.5	40.2	48.3	54.1	58.2	60.8	62.2	62.9	62.1	455
PV @ 30%	-38.9	13.2	21.1	24.4	24.7	23.5	21.4	18.9	16.4	14	11.7	150.3
PV @ 50%	-38.9	11.5	15.9	15.9	14	11.5	9.05	6.9	5.2	3.9	2.8	57.6
PV @ 80%	-38.9	9.6	11	9.2	6.7	4.6	3	1.9	0.9	0.7	0.5	9.3
PV @ 100%	-38.9	8.6	8.9	6.7	4.4	2.7	1.61	0.92	0.5	0.3	0.2	-4.04
PV @ 150%	-38.9	6.9	5.7	3.4	1.8	0.9	0.4	0.2	0.09	0.04	0.02	-19.4

Table 7. Cash Flows for Fractured Case (At $X_f = 3000$ ft, $W_f = 0.1$ ft, $K_f = 3000$ md).

Time (Yrs)	0	1	2	3	4	5	6	7	8	9	10	NPV
Gp(BSCF)	0	14.4	28.8	43.2	57.6	72	86.4	100	115	129	142	
Np(MMSTB)	0	0.253	0.491	0.684	0.834	0.941	1.011	1.048	1.057	1.057	1.057	
CAPEX(\$MM)	-39.4	0	0	0	0	0	0	0	0	0	0	
OPEX(\$MM)	0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	
Gross Rev (\$MM)	0	36.4	72.3	107	140.2	172.2	203.1	233	262.1	291	316	
NCR(\$MM) b/4 Royalty and Tax	-39.4	33.4	69.3	104	137.2	169.2	200.1	230	259.1	288	313	
Royalty + Tax (\$MM) 48.5% of NCR	0	16.2	33.6	50.4	66.5	82.1	97.0	111.6	125.7	139.7	151.8	
NCR (\$MM) after Royalty and Tax	0	17.2	35.7	53.6	70.7	87.1	103.1	118.5	133.4	148.3	161.2	
CUM. NCR (\$MM)	-39.4	-22.2	13.5	67.1	137.8	224.9	328	446.5	579.9	728.2	889.4	
PV @10%	-39.4	15.6	29.5	40.2	48.3	54.1	58.2	60.8	62.2	62.9	62.2	453.5
PV @ 30%	-39.4	13.2	21.1	24.4	24.7	23.5	21.4	18.9	16.4	14	11.7	149.8
PV @ 50%	-39.4	11.5	15.9	15.9	14	11.5	9	6.9	5.2	3.9	2.8	57.1
PV @ 80%	-39.4	9.6	11	9.2	6.7	4.6	3	1.9	1.2	0.7	0.5	9.1
PV @ 100%	-39.4	8.6	8.9	6.7	4.4	2.7	1.61	0.92	0.5	0.3	0.2	-4.5
PV @ 150%	-39.4	6.9	5.7	3.4	1.8	0.9	0.4	0.2	0.09	0.04	0.02	-19.9

Table 8. Summary of the Economic Analysis Carried Out.

CASES CONSIDERED	NPV @ 10% (MM\$)	DCF-ROR (%)	PAY-OUT (YEARS)	PROFIT PER DOLLAR INVESTED (MM\$)
Case 1: Natural Depletion Without Fracture	445.8	88	1.52	24.4
Case 2: Fractured Case at $X_f = 1000$ ft, $W_f = 0.03$ ft, $K_f = 1000$ md	455.5	92	1.59	23.2
Case 3: Fractured Case at $X_f = 2000$ ft, $W_f = 0.06$ ft, $K_f = 2000$ md	455	87	1.6	22.9
Case 4: Fractured Case at $X_f = 3000$ ft, $W_f = 0.1$ ft, $K_f = 3000$ md	453.5	88	1.62	22.6

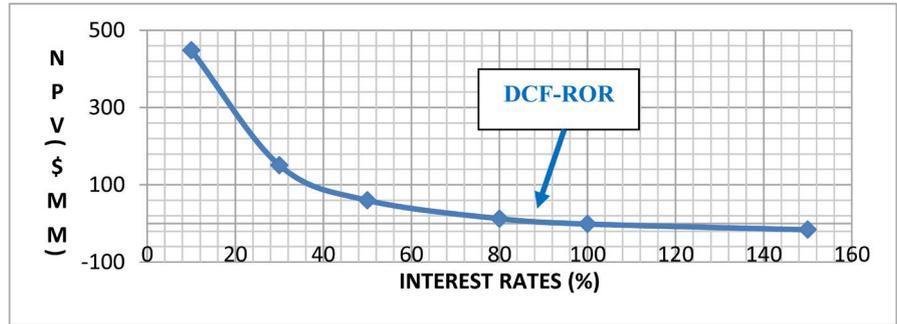


Figure 1. NPV against DCF-ROR for Natural Depletion without Hydraulic Fracture.

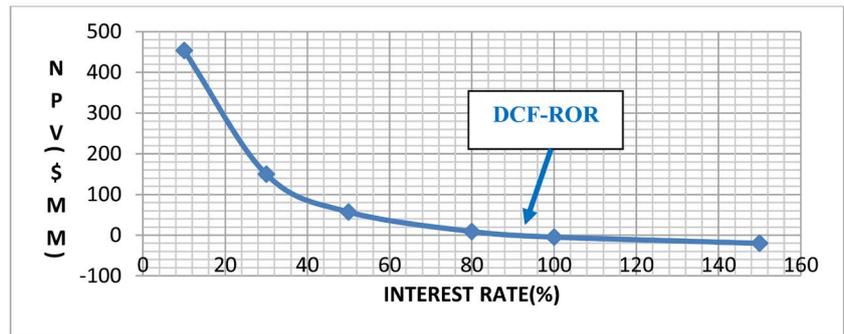


Figure 2. NPV against Interest Rates for Fractured Case at $X_f = 1000$ ft, $W_f = 0.03$ ft, $K_f = 1000$ md.

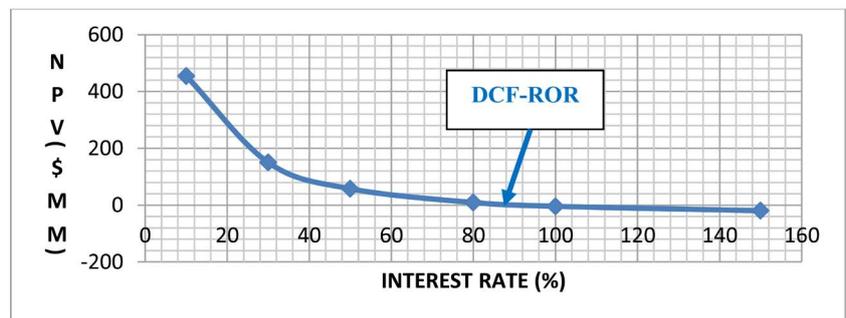


Figure 3. NPV against Interest Rates for Fractured Case at $X_f = 2000$ ft, $W_f = 0.06$ ft, $K_f = 2000$ md.

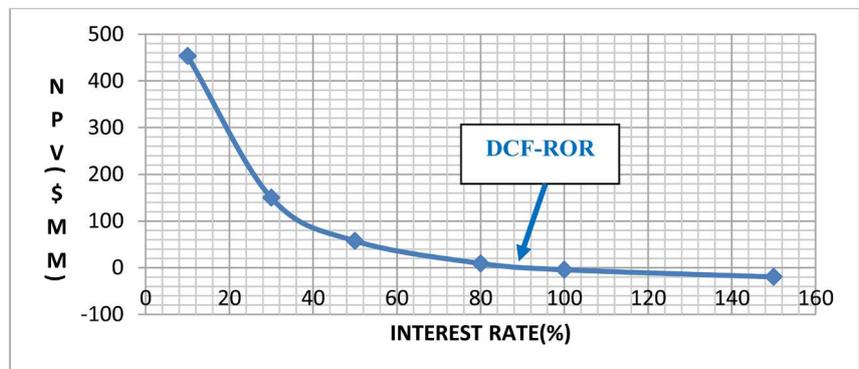


Figure 4. NPV against Interest Rates for Fractured Case at $X_f = 3000$ ft, $W_f = 0.1$ ft, $K_f = 3000$ md.

6. Conclusions

The results of the economic analysis of hydraulic fracturing from a gas condensate reservoir operating below dewpoint show that:

1) The additional liquid recovered by continuous increase in fracture half-length, fracture width and fracture permeability may not be able to offset the additional cost incurred by hydraulic fracturing. This is because the reservoir contains a lean gas condensate fluid which is characterised with a low liquid yield. This is manifested by the profit per dollar invested calculated.

2) The NPV obtained by fracturing the reservoir at a fracture half-length of 1000 ft, fracture width of 0.03 ft and fracture permeability of 1000 md gave the highest amount when compared with the NPV obtained when the reservoir is unfractured and that obtained by fracturing the reservoir at other fracture parameters.

3) Fracturing the reservoir at $X_f = 1000$ ft, $W_f = 0.03$ ft and $K_f = 1000$ md gave a higher DCF-ROR when compared with other cases considered. Fracturing the reservoir gave a later payout which resulted from the additional cost incurred due to fracturing.

4) Also fracturing the reservoir resulted to a 10.2% increase in the additional liquid recovered after the simulation period compared with the cumulative liquid recovered when the reservoir was unfractured.

Acknowledgements

The authors greatly appreciate the assistance of O'bmond Energy Nig. Ltd. for providing the data utilized in this study. Special thanks to Engr Chijioke Eze of O'bmond Energy Nig. Ltd. for his advice.

Conflicts of Interest

The authors declare no conflicts of interest regarding the publication of this paper.

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Nomenclature

NPV = Net Present Value

FV = Future Value

i = Interest Rate

t = Time

PO = Pay out

NCR = Net Cash Recovery

NCF = Net Cash Flow

DCF-ROR = Discounted Cashflow Rate of Return

X_f = Fracture Halflength

W_f = Fracture Width

K_f = Fracture Permeability

CAPEX = Capital Expenditure

API = American Petroleum Institute

GOR = Gas Oil Ratio

I.D = Internal Diameter

FLPT = Field Liquid Production Total

FGPT = Field Gas Production Total