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Effect of Horizontal Well Length Variation on Productivity of Gas Condensate Well

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Abstract

The development of gas reservoirs and the key decisions to be made concerning gas reservoirs such as the number of wells to drill, well fracturing and capacity of the surface processing facilities are dependent on its productivity. Condensate blockage caused by liquid build up is difficult to control in the aforementioned reservoirs thereby affecting production. In this work, production is optimized from gas condensate reservoirs using horizontal wells. This is to demonstrate the performance of horizontal wells and vertical wells in gas condensate reservoirs and to study the effect of well length on horizontal well productivity and condensate recovery. A compositional simulator was used to carry our reservoir simulations on a 3D-model with properties similar to the typical Niger Delta gas condensate reservoir. The results of the sensitivity analysis of horizontal well length impact on productivity and the comparison between production capacity of a gas condensate well with the use of both vertical and horizontal wells using the criteria: drawdown pressure, condensate saturation build-up, well production rates, cumulative production, showed that the horizontal wells performed better than the vertical wells.

INTRODUCTION

The need for natural gas is expected to increase in the coming years owing to the facts that it is the cleanest fossil fuel compared to other fossil fuels. This is in line with environmental concerns (Wilson, 2003). It was estimated that most of the world's 6606.6 trillion cubic feet (TCF) gas reserves lay in gas/gas condensate reservoirs (See figure 1).

Afidick, Kaczorowski and Bette, (1994) defined a gas condensate reservoir as a "reservoir whose temperature is between the critical temperature and cricondentherm of the reservoir fluid." Also they defined a condensate as a "low-density, high API gravity liquid hydrocarbon phase that generally occurs in association with natural gas."

In gas condensate reservoirs, once reservoir initial pressure gets below dew point pressure and liquid is liberated from the gas, there is an accumulation of liquid in the near wellbore region which restricts gas flow through the well. When the gas condensate saturation surpasses the critical condensate saturation, the condensate flows and consequently decreases the relative permeability of the gas drastically leading to decline in the well deliverability.

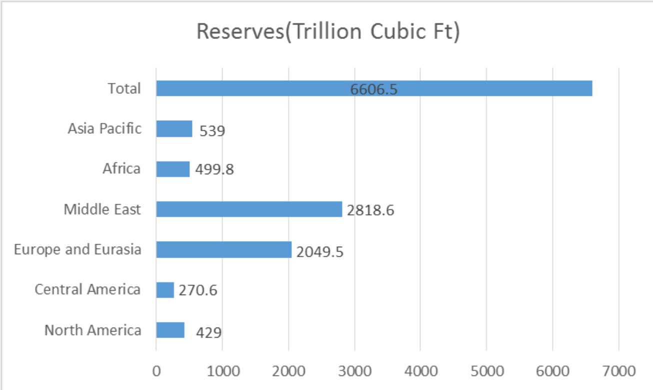

Figure 1: Global Natural Gas Reserves (BP Statistical Review of World Energy June, 2015).

Fan et al., (2005) noted that during production, the condensate liquid saturation builds up near the wellbore as reservoirs pressure falls below the dew point pressure which reduces or restricts gas flow. This reduction or restrictions great affects the productivity of the well and reservoir. This is known as condensate blocking. They pointed out that processes like gas cycling, hydraulic fracturing, use of horizontal or inclined wells, shutting in the well, and cyclic injection can reduce the effects of condensate blocking and improve flow, however, none of these options has proven to be durable.

Sognesand, (1991) in his work stated that horizontal wells would not prevent condensate drop out. However, by increasing reservoir contact using horizontal wells, a viable solution is in view as it offers more flow. The enlarging of the wellbore has had better long term performance (Sognesand, 1991).

The effect of horizontal well length variation on the productivity of gas condensate well is studied in this work in order to present and efficient and optimum process for the improving of the flow of gas by reducing the buildup of condensate in areas around the wellbore. This research focuses on optimizing productivity of a gas condensate reservoir by varying the horizontal well length.

Fevang and Whitson, (1996) presented an efficient and rather simple model of a gas condensate reservoir being depleted, showing three flow regimes; the region in closest proximity to the wellbore where the flow of gas and liquid is simultaneous but their velocity differs mostly because of the effects of relative permeability, the region where only the gas flows, although the condensate is present but the critical saturation has not been exceeded for the gas to flow thus it remains stationary and starts to accumulate leading to condensate buildup and the region that is most distant from the well where the reservoir fluid exists as a single phase gas due to the fact that the reservoir initial pressure has not dropped below the dew point pressure.

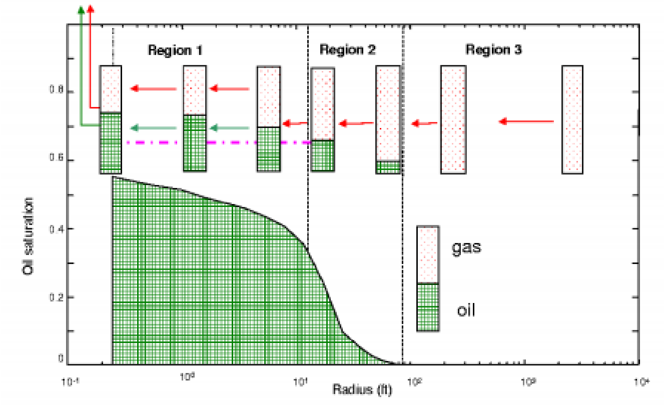

Figure 2: Schematic Gas-Condensate Flow Behavior (Fevang and Whitson 1995).

A formation damage, referred to as "condensate banking", is caused by liquid build-up around the wellbore and this occurrence dramatically reduces the performance of the well (Giamminonni et al 2010; Miller et al, 2010). This leads to the reduction of condensate and gas production.

Afidick, Kaczorowski and Bette (1994) did a study on the declined productivity of Arun gas condensate reservoirs which resulted from the accumulation of condensate. From experimental PVT analysis it was deduced that the fluid in the reservoir was a gas condensate which was lean and possessed a liquid dropout of 1.1% at maximum. The production decline exhibited by the reservoir as the pressure in the reservoir drops below the dew point pressure was said to be caused by the effect of liquid build-up in the region of the wellbore. This condensate accumulation in areas of the wellbore region was confirmed by a series of well tests analysis carried out on the wellbore from the cores of the reservoir.

Shell and Petroleum Development Oman described a productivity loss of 67% for wells in two fields (Smits, Van der Post, et al. 2001). Several of the biggest gas condensate reservoirs in the world such as the Cupiagua Field in Colombia (Lee and Chaverra 1998), the Karachaganak Field in Kazakhstan (Al-Shammasi and D'Ambrosio 2003, Albertini, Bigoni, et al. 2014), and the "Alpha" Field in Nigeria which is located in the northern Delta depositional belt of the Niger Delta have a common issue: condensate banking.

As Condensate banking is experienced in gas condensate reservoirs, the extent to which condensate drops out is a problem of production that hinges on on the ratio of the pressure drop that occurs inside the reservoir to the total pressure drop experienced from distant areas of the reservoir to a control point at surface. If pressure drop is substantial, then additional pressure drop due to condensate banking can be important for well deliverability. This condition is mainly applicable in a formation with a low horizontal permeability, low product of permeability and low net formation thickness. Contrarily, if the pressure drop occurs in a formation of high horizontal permeability, the additional pressure drop due to condensate banking will have little impact on well deliverability. A general guideline states that "condensate banking is assumed to be double the pressure drop in the reservoir for the same flow rate" (El-Banbi, McCain Jr, et al. 2000).

Many experimental and numerical studies have been carried out to reduce the effect of condensate saturation near the well, they may sufficiently improve flow but none of these options has proven to eradicate condensate banking. Some studies focused on reducing interfacial tension and increasing viscous forces, while others concentrated on gas injection, hydraulic fracturing and aziding, wettability alternation and horizontal well design.

Al-Shammasi and D'Ambrosio (2003) explored reducing interfacial tension (IFT) so as to decrease the saturation of the condensate. They recognized problem areas in behaviors of condensate, and suggested the need for "core flooding research and physical equilibrium property measurements." They disclosed how IFT can affect liquid mobility in a gas condensate system for a near critical fluid. Theinfluence of IFT on liquid mobility was examined, and it showed that low-tension partial pressure maintenance was an effective production procedure and found that gravity had a strong effect on low-tension depletion.

Boom, Wit, et al. (1996) also experimented on core materials from gas condensate reservoirs. They explored increasing viscous forces to decrease condensate banking near the wellbore. They concluded after using model experriments that both the wetting and non-wetting are substantially increased. Also, that the wetting phase relative permeability from the experiment can be integrated into field developments.

In a work by Li and Firoozabadi (2000), they investigated the reduction of condensate banking by increasing viscous forces, they studied a "phenomenological simple network model" to understand the effects of viscous forces, gravity, and wettability on critical condensate saturation and relative permeability of gas condensate systems. They observed that wettability significantly affects both critical condensate saturation and relative permeability. Results obtained suggested that the deliverability of the gas well in gas condensate reservoirs can be improved by altering the wettability near the wellbore but there has not been any field application.

Al-Anazi, Walker, et al. (2003) conducted a laboratory test and single-well numerical simulation to examined the removal of condensate banking using methanol as solvent in near wellbore region. Compatibility tests were carried out to guarantee that the injection of methanol did not damage the core sample obtained from the field and also, tests were also conducted to check for precipitation of salt during methanol injection. Based on the success of the laboratory experiment, a field test was carried out in the Hatter's Pond field, Alabama, USA (Fan et al. 2005).

Ahmed, Evans, et al. (1998) studied gas injection process as a method for the reduction of gas-well productivity losses as a result of condensate banking around the wellbore. They examined the feasibility of reducing condensate saturation near the wellbore by cyclic injection, often known as Huff and Puff injection. This injection process served as a pressure maintenance technique that uses dry gases such as methane, carbon dioxide & nitrogen to vaporize condensate around the wellbore. This proved to have a short-term benefit for increasing productivity, but the banking effect returned when the formation pressure drops below the dew point pressure of the current gas mixture. They observed that it is important to select the optimum injection volume and pressure for the effective use of the Huff "n" Puff technique; and also insisted that the method should be initiated before maximum liquid dropout. Nevertheless, the results of this study revealed that the injection gas used can increase the liquid blockage when they are injected with small volume. The "Huff 'n' Puff" technique was carried out in the Anschutz Ranch Field by Saudi Aramco, the process worked on a small scale but it required a significant cycling of wells and large investment in compressors and pumps (Al-Anazi, Sharma, et al. 2004).

In an experiment conducted by Barnum, Brinkman, et al. (1995b) using hydraulic fracturing and acidizing on a gas condensate field, they observed that the well returned to its initial production rates. Conversely, hydraulic fracturing did not produce a conduit past condensate banking area. Antoci, Briggiler, et al. (2001) also conducted experiments using hydraulic fracturing and acidizing on a gas condensate field in Argentina experiencing condensate banking problems. Rather than using the conventional water based fluid to stimulate the blocked area, methanol was used instead. They observed that methanol as the stimulant vaporized the condensate saturation around the wellbore and also increased the effective fracture length thus resulting to increased well productivity but at the expense of higher treatment cost

Muladi and Pinczewski (1999b) carried out a simulation study on the "application of horizontal wells in a gas condensate reservoir", they observed the "difference in production performance between horizontal and vertical wells for different heterogeneities in a gas condensate reservoir". They found out that horizontal wells have better performances than vertical wells when applied in high average permeability reservoirs. They also observed in horizontal wells, critical condensate saturation has no direct consequence on well deliverability due to increased reservoir contact, even though gas relative permeability appears to be reduced as a result of condensate banking but this will not meaningfully affect the well performance enough, compared to vertical wells.

Dehane, Tiab, et al. (2000) investigated horizontal and vertical wells performances for a gas condensate reservoir under various depletion scheme in the Djebel Bissa Field, Algeria. They observed the drawdown pressure for horizontal well was low, compared to vertical well under the same flow rate, considerably minimizing condensate saturation. They also observed for the same production rate, the liquid saturation around a horizontal well does not exceed 6% and that for a vertical well can reach a value of 15%. They studied the "effect of horizontal well length section and reservoir thickness on horizontal well productivity and condensate recovery". They observed that reservoir thickness affects condensate recovery and pressure drawdown.

Harisch, Bachman, et al. (2001) evaluated a horizontal gas condensate well using "numerical pressure transient analysis." They found that multiphase effects had little influence on the pressure response of the system although horizontal well fluid flow regimes, driven by reservoir permeability appeared to be dominant. Hashemi and Gringarten (2005b) used reservoir simulation to measure the "increase in well productivity from different remediation solutions and evaluate their effectiveness in gas condensate reservoirs." They observed that horizontal wells compared to vertical wells, increased productivity in dry gas systems; their performance was even better in gas condensate reservoirs below the dew point since they decrease pressure drawdown and condensate banking.

For this work, a compositional reservoir simulator will be used to assess if horizontal wells can increase productivity more efficiently than vertical wells, specifically in the "ALPHA'' Field located in the Niger Delta Basin. Drawdown pressures for the ALPHA field horizontal well will be compared with the drawdown pressures of the ALPHA field vertical well, also the productivity index for the horizontal well and vertical well in the ALPHA field will be compared.

Proper understanding of gas condensate reservoirs is important because of the retrograde phenomena associated with it. Various literatures have established that horizontal wells has a noteworthy advantage over vertical wells (Engineer 1985, Muladi and Pinczewski 1999b, Dehane, Tiab, et al. 2000, Harisch, Bachman, et al. 2001, Hashemi and Gringarten 2005b). Over the last decade, horizontal well technology has developed significantly due to the advantages it offers over vertical wells such as (Joshi 1987, Lacy, Ding, et al. 1992, Mitchell 1995). It minimizes or eliminates production problems such as water and gas coning, provides large reservoir contact area, drains multiple zones by intersecting high permeability areas. Additionally, horizontal wells tend to decrease drawdown for a certain production rate and thus reducing condensate dropout (Muladi and Pinczewski 1999b, Dehane, Tiab, et al. 2000, Hashemi and Gringarten 2005b). This influences positively the productivity of a gas condensate reservoir, as less condensate banking will occur. (Miller, Nasrabadi, et al. 2010) experimented with "the application of horizontal wells in a giant gas condensate reservoir in the North Field, Qatar "and they observed that horizontal wells reduced condensate banking. The results indicated that horizontal wells have smaller drawdown compared to vertical wells, which lead to a delay in reaching the dewpoint pressure compared to vertical wells. The main advantage being that horizontal wells offer higher gas rates and increased liquid recovery and this was verified by Lacy, Ding et al (1992).

METHODOLOGY

A box model was built to depict a gas condensate reservoir since there was no access to full real field data. Also, the simulator helped to make some basic assumptions which are related to gas condensate reservoirs. A Cartesian grid block of number of cells 9X9X4 in the X, Y, and Z direction was used. The sizes of the grid blocks in the X, Y, and Z directions were 400, 300 and 10 respectively. The reservoir had a total number of 324 cells with 290 being active cells and 34 inactive cells. The reservoir had a permeability function of 400 in the X direction, 300 in the Y and 30 in the Z, with a porosity of 0.3. The ratio of the vertical to horizontal permeability was 0.1. The reservoir rock and fluid properties are described in table 1. Peng-Robinson (PR) equation of state was used to initiate a proper reservoir fluid. PR EOS was used because it shows a better trait of the reservoir fluid at the critical point. Also, a slightly better performance around the critical conditions makes PR EOS somewhat better suited to model gas-condensate systems. A dynamic simulation model was built using the grid and property data and the model was initialized to obtain initial reservoir conditions (figures 4,5,6 and 7) i.e. volumes estimates and reservoir fluid saturation distribution then prediction models were carried out to determine a) well deliverability using vertical wells and b) optimization technique using horizontal well designs.

Table 2 shows the equation of state parameters that are used to describe the model. The acentric factors in column eight of Table 2 are used to define the mixing laws. The volume shifts in column nine of Table 2 are used to determine the fugacity coefficients. The parachors in column ten of Table 2 are used to determine the surface tension between the liquid and vapor phase of a multicomponent mixture.

The vertical well was first put on stream while the horizontal well was shut in to validate the effect of vertical wells on gas condensate reservoir productivity. For maximum productivity, a run was made to both vertical and horizontal wells and also horizontal well lengths were varied.

Table 1: Reservoir rock and fluid properties

Porosity (%)	0.3	Permeability (mD)	30-400	Initial water saturation Sw,	0.2
Vertical – to horizontal permeability Ratio (kv/kh)	0.1	X- direction permeability, mD	400	Reservoir depth, ft.	2145
Y – direction permeability, mD	300	Z – direction permeability, mD	30	Initial reservoir pressure, psia	4500
Reservoir thickness h, ft.	40	Initial oil saturation So,	0	Dewpoint pressure, psia	3862
Initial gas saturation Sg,	0.8	Initial reservoir temperature, F	183.9	Initial gas viscosity (cP)	0.04
Water viscosity (cP)	0.465	Water Density (lbs/cuft)	63.03	Water Compressibility (1/psi)	2.43E-06
Rock Compressibility (1/psi)	6.00E-06	Condensate Initially In Place (MMSTB)	2.34	Gas Initially In Place (BSCF)	6.69

Table 2: Equation of state parameters

S/N	Names	TC (^{O}R)	Pc(psia)	Vc	Zc	MW	ACCENTRIC FACTOR	VOLUME SHIFT	PARACHOR
1	X1+	357.14	673.47	1.67	0.2369	16.32	0.0145	-0.1436	77.01
2	X2+	527.39	640.32	2.54	0.2768	34.36	0.1047	-0.1004	109.52
3	C4+	796.68	514.23	4.92	0.2578	65.28	0.2187	-0.0492	207.05
4	C10+	1119.30	356.14	8.65	0.2658	135.55	0.473	0.0215	394.21
5	C17+	1365.61	219.83	15.0	0.2268	237.89	0.7738	-0.5155	614.23

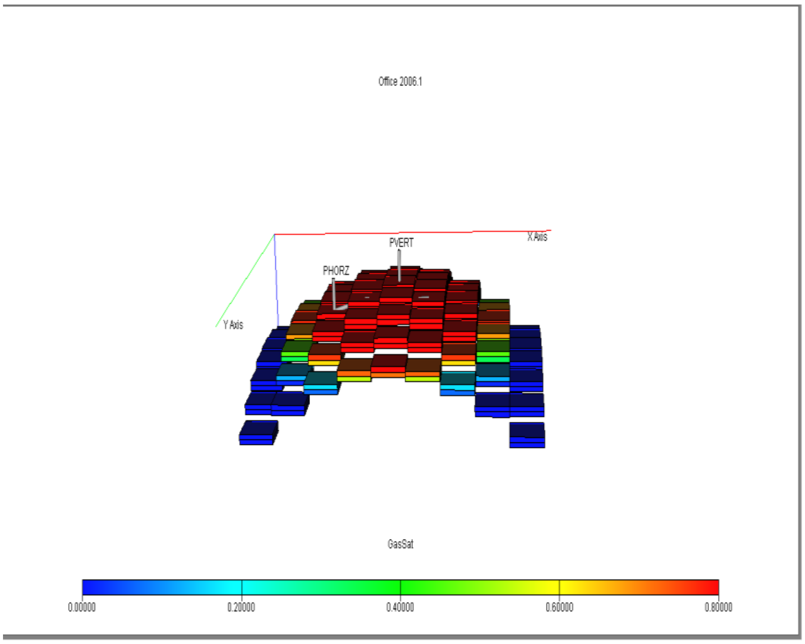

Figure 4: Gas saturation

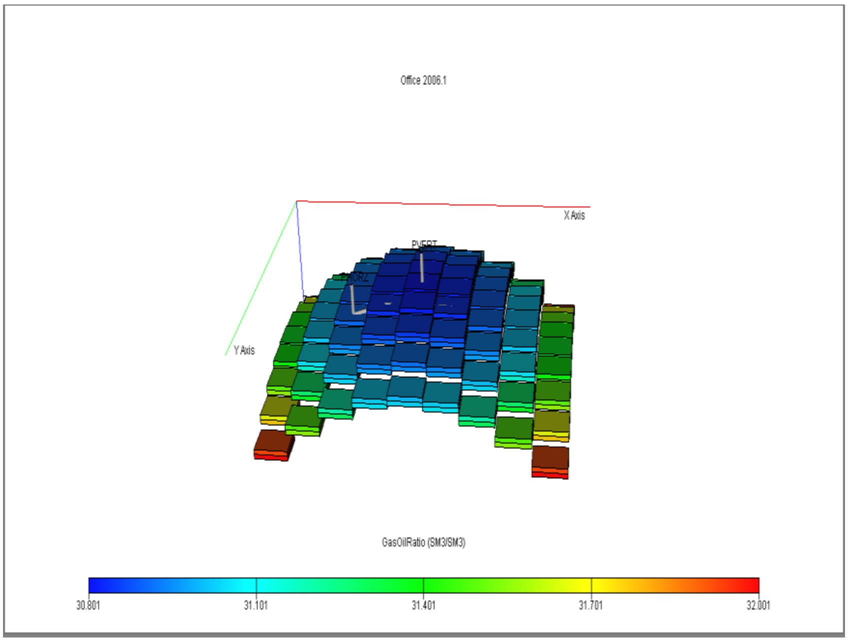

Figure 5: GOR ratio.

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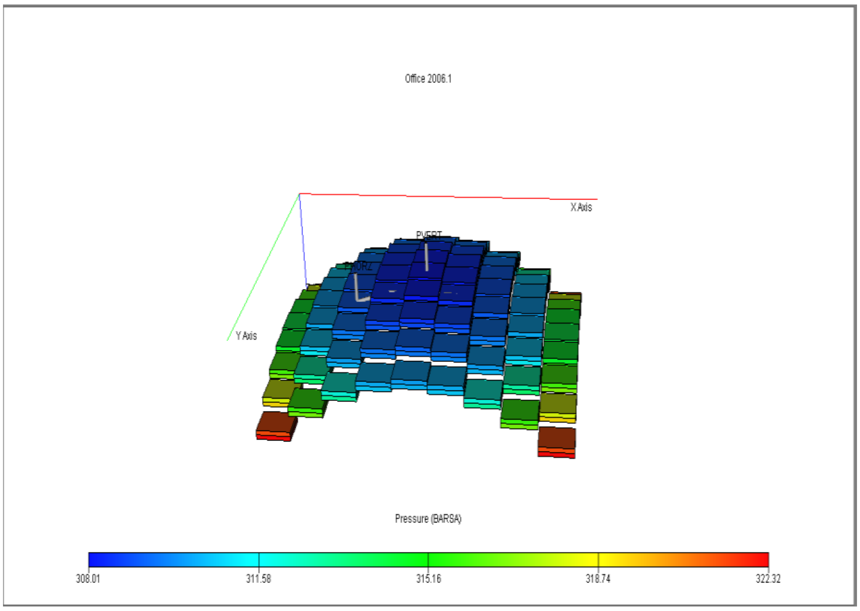

Figure 6: Pressure distribution.

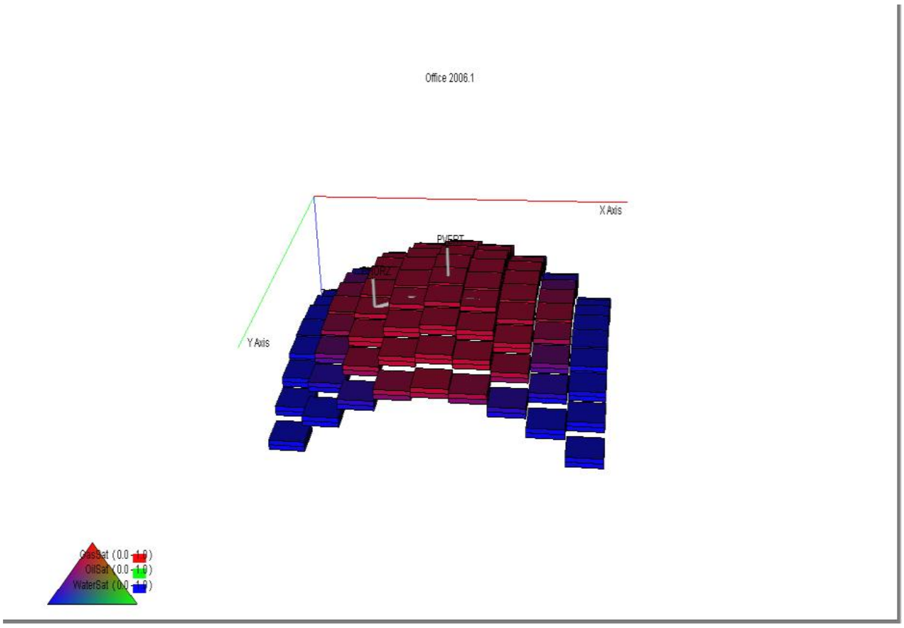

Figure 8: Ternary fluid distribution.

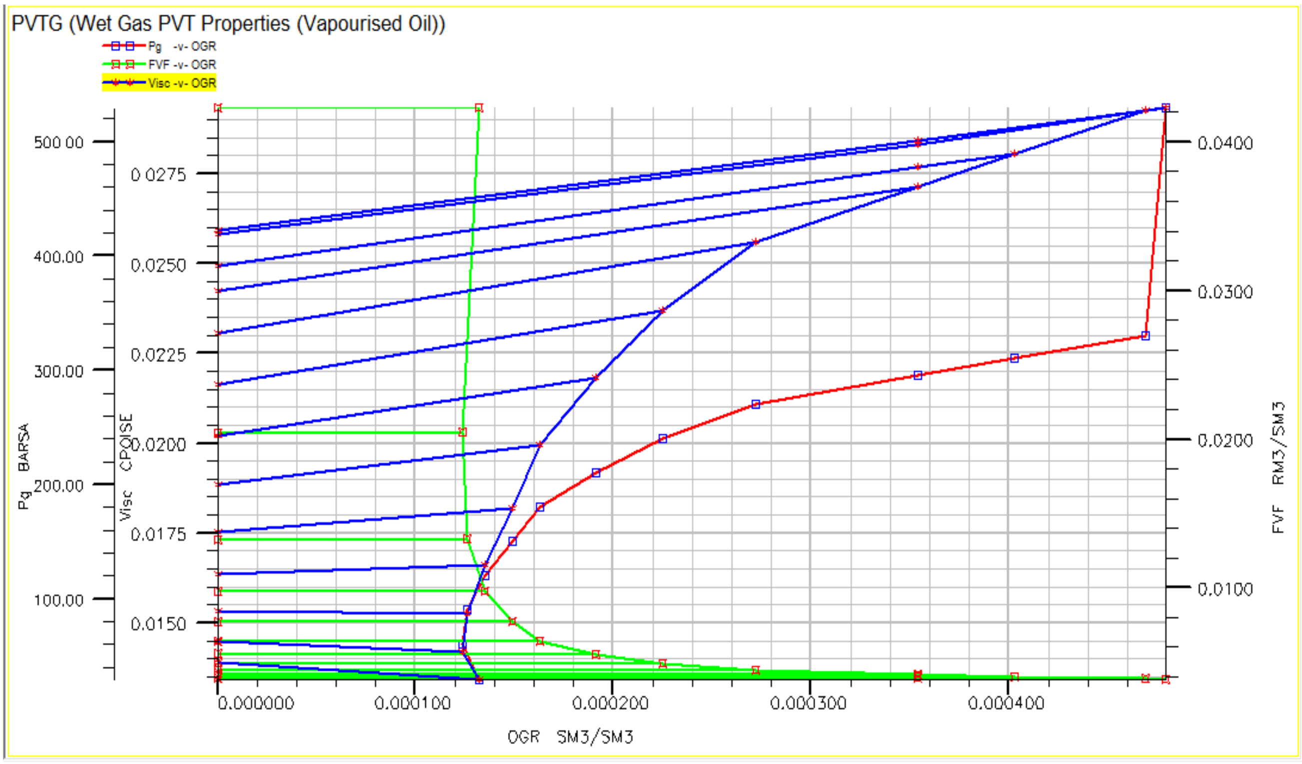

Figure 3: Wet gas PVT properties

For the relative permeability curves for water-oil and gas-oil, Corey's correlation were used to generate them.

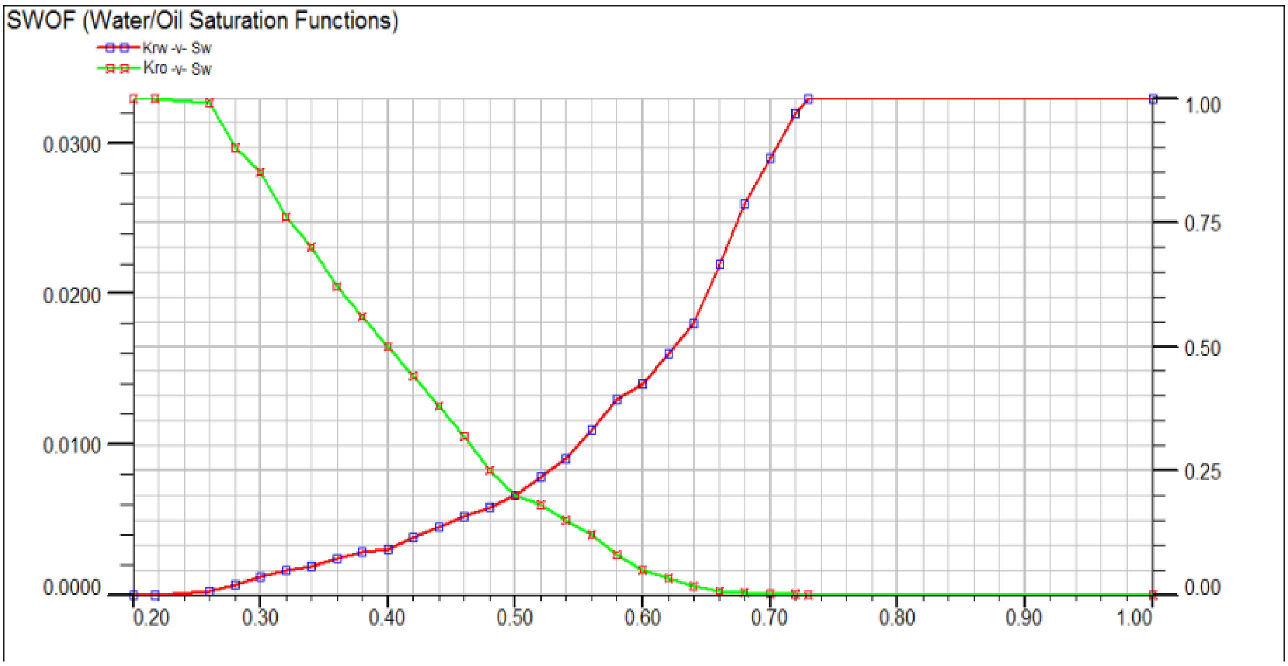

Figure 4: Water relative permeability curve

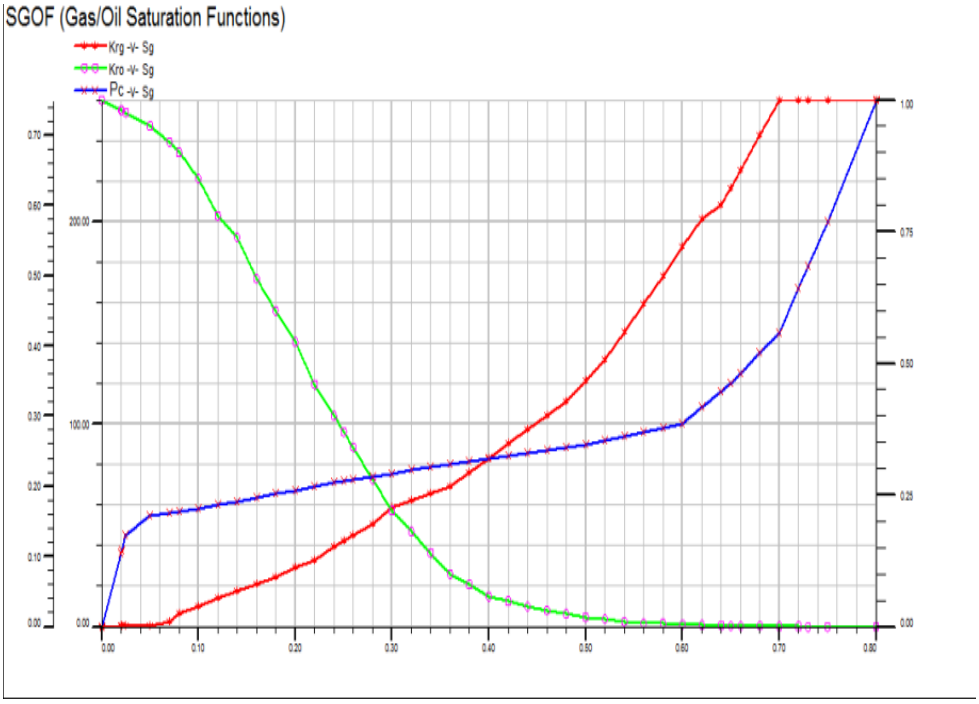

Figure 5: Gas-Oil relative permeability function

After the simulation runs, the vertical well performance was compared with the horizontal well performance. Also, a sensitivity analysis was carried out on the horizontal well length to determine its effect on productivity. The maximum gas production rate, minimum bottom hole pressure and simulation time were constrained to 4000MSCF, 2000psia and 5 years respectively.

RESULTS AND ANALYSIS

For the comparison between the vertical and horizontal wells, the following criteria was used: drawdown pressure, condensate saturation build-up, well production rates, and cumulative production. For the sensitivity analysis, 1118ft was the base case for the horizontal well length.

Drawdown pressure comparison:

The green and red lines in figure 7 show the pressure drop both in the vertical and horizontal wells. This sharp pressure decline gives an indication that the aquifer strength could be weak. Although the pressure drop for the vertical and horizontal well was from 4351 psi to 73 psi, it took a longer period of time 11900 days for pressure to drop in horizontal wells compared to 11500 days in verticals wells. The figure below shows that the vertical well has a larger drawdown compared to the horizontal well. The bottom hole pressure drop for the vertical well was from 4300 psi to 2000 psia after 3.6 years and for the horizontal well exhibited the same nature as the vertical wells only that pressure dropped to 2000 psia after 4.3 years

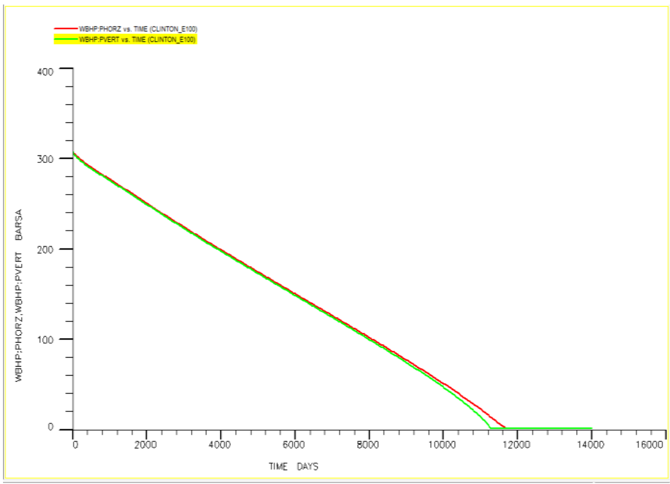

Figure 6: Vertical and Horzontal well pressure drawdown curve

Condensate saturation build-up:

The pressure drawdown for the vertical well (figure 8) causes the dew point pressure to be reached earlier for the vertical well (170 days) than the horizontal well (200 days) as can be seen in figure 8. The figure below also shows that condensate saturation forms on a much larger scale for the vertical well (0.16) than the horizontal well (0.06).

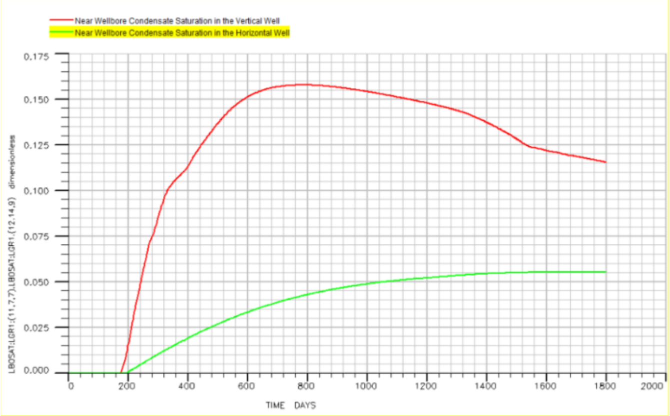

Figure 7: Condensate saturation build up between vertical and horizontal wells

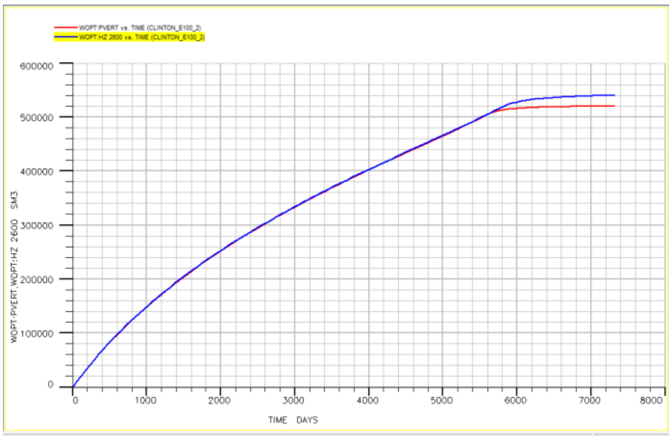

Figure 9: Cumulative condensate production for a vertical well vs. horizontal well.

Flow-rate and cumulative production:

Figure 9 shows that the condensate production rate drops significantly immediately condensate saturation begins to build-up around the wellbore. Condensate saturation build-up of 6% for the horizontal well reduced condensate production rate by about 81% before the well reached its bottom hole pressure limit of 2000 psia. Also, condensate saturation build-up of 16% for the vertical well reduced condensate production rate by 74% before the well reached its bottom hole pressure limit of 2000 psia.

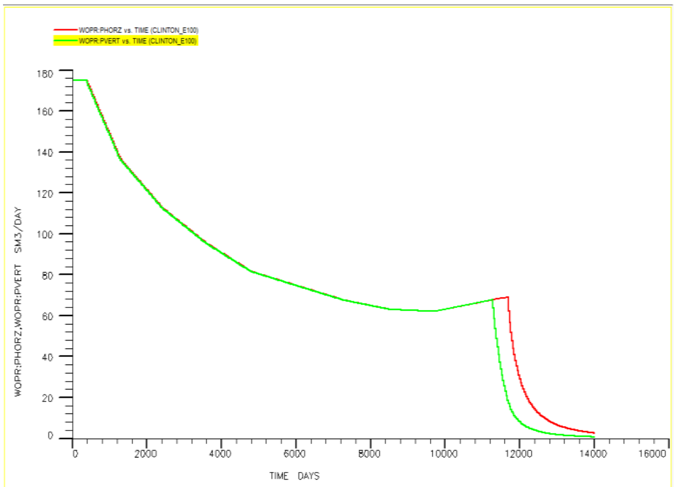

Figure 8: Plot of condensate production rate for vertical and horizontal well

Figure 10 shows the cumulative condensate production comparison between the horizontal and vertical well. The horizontal well gave a cumulative condensate production of 4.7 million barrels while the vertical well gave a cumulative condensate production of 4.5 million barrels. Hence, application of the horizontal well gave a condensate production increment of 4.3%.

From figure 11, it seen that the cumulative gas production for horizontal well is 109.4 billion scf, while that of the vertical well is 102.4 billion scf. Hence, application of the horizontal well gave an increment of 6.4%.

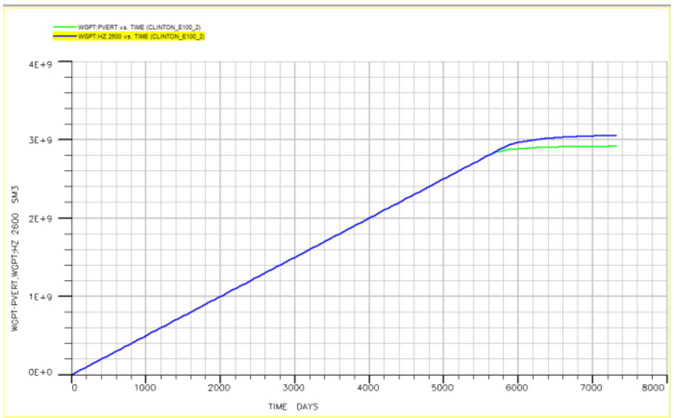

Figure 10: Cumulative gas production for horizontal and vertical wells

Sensitivity Analysis on Horizontal well length:

A sensitivity analysis was carried out to examine the influence of horizontal well length on pressure drop and condensate production to determine the optimal well length beyond which horizontal wells are uneconomic.

Case 1: Well length equal 2100 ft (Horizontal and Vertical)

The difference in condensate production between the vertical and horizontal well is: 0.09 MMstb. This is 2.04% increase in condensate production using horizontal well instead of vertical well. Horizontal well production was 1.02 times that of the vertical well. The difference in gas production between the vertical and horizontal well was: 1.35 billion scf. This is 1.40% increase in gas production using horizontal well instead of vertical well.

Case 2: Well length equal 2400 ft (Horizontal and Vertical)

Between the vertical and horizontal well, condensate production resulted to 0.26 MMstb. This is 5.68% increase in condensate production when using horizontal well instead of vertical well. Horizontal well production was 2.10 times the vertical well production. The difference in gas production between the vertical and horizontal well was: 4 billion scf. There was a 3.76% gain in gas production when using horizontal well.

Case 3: Vertical Well and Horizontal well with length equal 2600 ft

The difference in condensate production between the vertical and horizontal well was 0.35 MMstb. It implies a 7.49% increase in condensate production when using horizontal well instead of vertical well. The horizontal well production was 3.42 times the vertical well production. The difference in gas production between the vertical and horizontal well was: 7 billion scf. This is 6.4% increase in gas production when using horizontal well.

Tables 1 and 2 shows the cumulative condensate and Gas produced for the horizontal well lengths.

Table 3: Cumulative Condensate Production and Percentage Increase for different horizontal well length and vertical well.

case	Cum. Condensate Production (MMstb)	Production difference (MMstb)	Percentage Increase (%)
Vertical well (base case)	4.32	0	0
Horizontal well (2100 ft.)	4.41	0.09	1.4
Horizontal well (2400 ft.)	4.58	0.26	5.86
Horizontal well (2600 ft.)	4.67	0.35	7.49

Table 4: Cumulative Gas Production and Percentage Increase for different horizontal well length and vertical well.

case	Cum. Gas Production (Billion scf)	Production difference (Billion scf)	Percentage Increase (%)
Vertical well (base case)	102.4	0	0
Horizontal well (2100 ft.)	103.8	1.35	3.86
Horizontal well (2400ft.)	106.4	4	3.76
Horizontal well (2600 ft.)	109.4	7	6.4

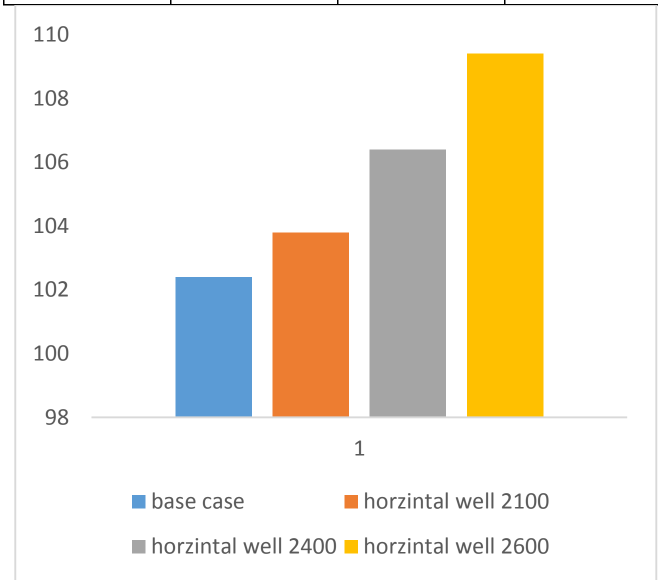

Figure 13: Cumulative condensate production for the four cases

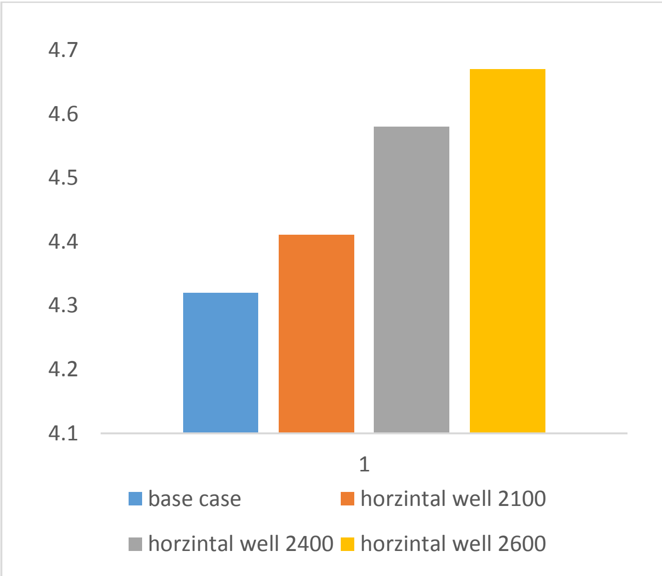

Figure 12: Cumulative gas production for the four cases

The figures 14 to 17 below show cumulative bottom hole pressure drops for all the cases, the gas production total for all wells, condensate production total for all wells and field production total.

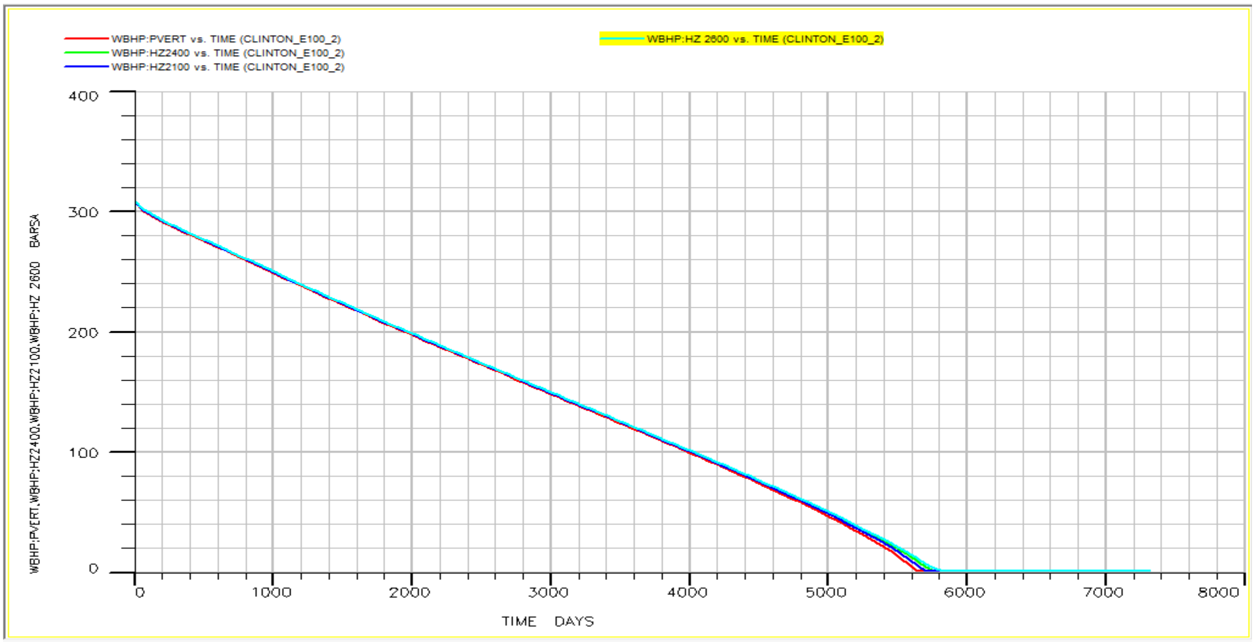

Figure 14: Cumulative pressure drop for all well

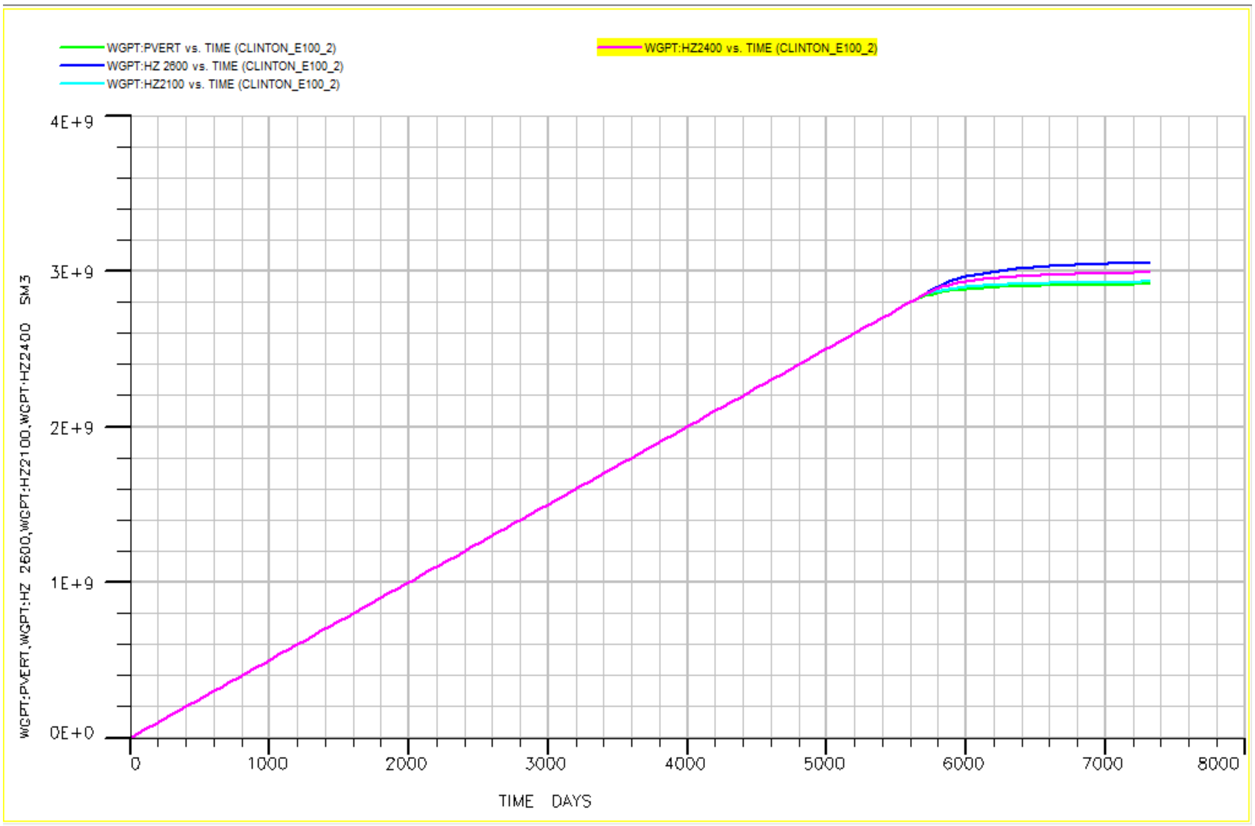

Figure 15: Gas production total for all wells.

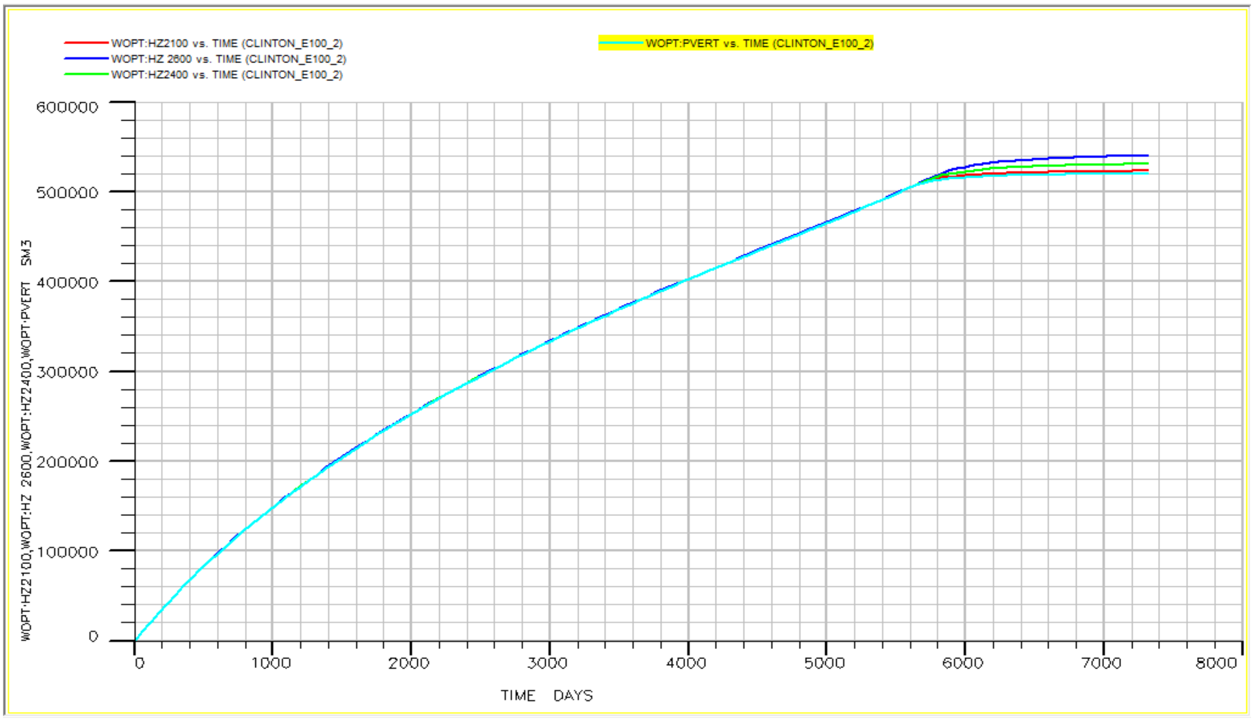

Figure 16: Condensate production total for all wells

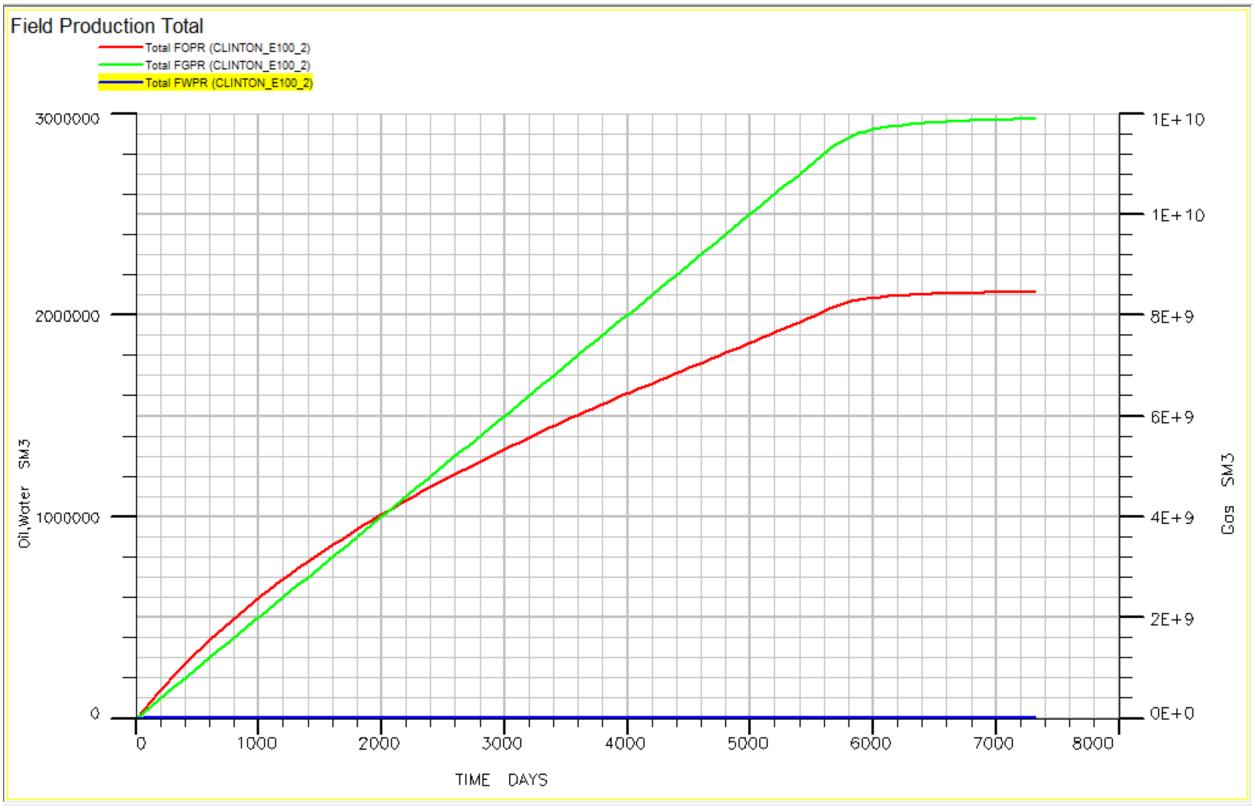

Figure 17: Field production total.

CONCLUSION

From the results of the comparison between production capacity of a gas condensate well with the use of both vertical and horizontal wells under the criteria's of: drawdown pressure, condensate saturation build-up, well production rates, cumulative production. It can be inferred that the horizontal wells showed better production performance. For the drawdown pressure comparison criterion, the horizontal well exhibited a slower decline which extended the time to reach dew point pressure thereby restricting the effects of condensate blockage. The condensate saturation build-up was deterred for an extended period of time in horizontal wells, which in turn increased the productivity of the wellbore for longer period of time. Also, the well flow rate of the condensate was reduced drastically, therefore leading to the effective production of gas. Finally, as regards the cumulative production, it was observed that the horizontal well performed better.

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