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The Impact of Different Completion Parameters on Well Performance of Gas Unconventional Reservoirs

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Abstract— Unconventional reservoirs are defined as reservoirs that cannot be produced at economic flow rates or that do not produce economic volumes of oil and gas without assistance from massive stimulation treatments or special recovery process. Shale and tight reservoirs are low quality reservoirs with low permeability. This low permeability can be as low as 100 Nano decries. . Well performance in gas unconventional reservoirs is greatly affected by different completion parameters of the horizontal wells. These completion parameters include number of frac stages, frac face skin, production under different draw down or (p_i - p_{wf}) and the effect of production from different drainage areas. In this study, these parameters will be studied and quantified for proper analysis of long-term linear flow periods associated with tight/shale gas production.

Index Terms— Unconventional reservoirs, low permeability, . Well performance, , frac face skin, tight/shale gas, hydraulic fracture , completion configurations, draw down

1. Introduction

Horizontal drilling and multistage hydraulic fracture are the two key enabling technologies for the economic development of ultralow permeability reservoirs as tight and shale gas reservoirs (permeability in Nano Darcy).The use of multi-fractured horizontal wells is expected to create a complex sequence of flow regimes.

Well performance of gas unconventional reservoirs is greatly affected by the different completion configurations between the reservoir and the horizontal well. Completion parameters that greatly affect the well performance include the number of frac stages, frac face skin, production under different draw down or (p_i - p_{wf}) and the effect of production from different drainage areas. These parameters should be studied and quantified for proper analysis of long-term linear flow periods associated with tight/shale gas production.

2. Methodology

GASSIM simulator is used, GASSIM is a single phase, 2D simulator that is originally developed to simulate real gas flow in both x-y and r-z domain. Later, it was modified to include the ability to simulate liquid case. It is written in Visual Basic code for Excel. It has been used extensively in previous studies and proved to give accurate solutions.

3. The effect of number of the frac stages .

The effect of the number of stages of the hydraulic fractures on well performance of gas unconventional reservoirs can be studied in terms of the frac spacing.

From **Fig.1** The spacing between two successive fracs

$$=\frac{l_e}{n} \tag{1}$$

Where $l_e$the horizontal well length and n is is the number of stages.

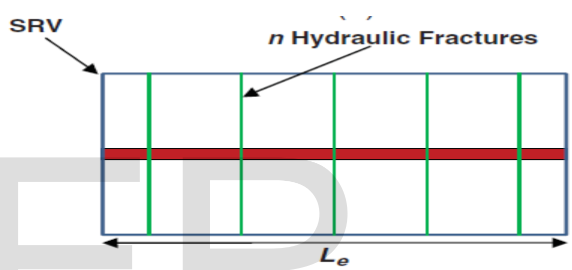

Fig.1- Horizontal well with length $l_e$and number of stages n.

For fixed well length, increasing the number of stages, decreases the frac spacing. The input data to GASSIM is summarized in Table1. The production rates for different stages (n= 2, 5, 10, 15,20,25, 30 and 40) are shown in Fig. 2 The time to the end of formation linear flow or the time to the end of half slope period (t_{esh}), estimated ultimate recovery (EUR) if the economic limit is 3MSCF/D, the recovery factor and the productivity index is summarized in **Table 2.**
Increasing the number of the frac stages will result in a decrease in the time to the end of transient linear regime or a decrease in the time to the end of half slope period t_{esh}as shown in **Fig. 3** The time to the end of half slope period is decreased due to the decrease in the stimulated drainage volume for each stage which will cause a rapid depletion of the reservoir fluid. Mathematically:

Stimulated volume for each stage is:$\frac{4x_f * y_e * h}{n}$. (2)

Eq.2 is valid if there is no drainage at the symmetry line between to successive fracs, so that each stage has its own drainage volume or in other words no frac interference occurs.

Increasing the number of stages also decrease the total time needed to deplete the reservoir due to increasing the production rate as shown in **Fig.4** Mathematically:

The total production of the total stages

= n* production of single stage (3)

Eq.3 is valid if we assume that all stages are identically and equally spaced.

Although the initial rate increases with increasing the number of stages ,the ratio of the initial rate to the rate at the beginning the boundary dominated flow decreases which indicates that the decline rate is higher when more stages are added as shown in **Fig. 5**.

Increasing the number of stages also results in an increase in the productivity index (*PI*).The increase in the productivity index is a result of the increase in the production rate with increasing the number of stages under constant bottom hole flowing pressure i.e. constant p_{wf} as shown in **Fig. 6.**

Table 1- The input data to GASSIM to simulate the effect of changing the number of stages on well performance.

γ_g	0.7
T	240 F° =700 R^{o}
p_i	5000 psi
p_{wf}	1000 psi
h	300 ft
r_w	0.35 ft
c_f	$6*10^{-6}$
c_w	$3.6*10^{-6}$
s_w	0.4
$\emptyset$	0.1
k	.0004 md
x_f	500 ft
f_c	1000 md-ft
l_e	5000 ft
w	1000 ft

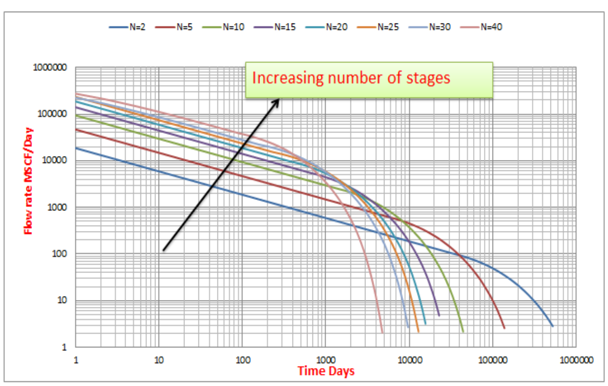

Fig. 2- The production rate for different stages on the same graph .

Table 2- Summary of t_{esh}, EUR, total time, RF and PI for different values of n.

Number of stages	t_{ehs} *years*	*EUR BSCF*	*Total time Years*	*RF %*	*PI MSCFD/psia²/cp*
2	100.1	17.03	1434.6	76.4	$1.79*10^{-7}$
5	16.016	17.4	378.4	78	$1.12*10^{-6}$
10	4	17.4	121.1	78.2	$4.52*10^{-6}$
15	1.78	17.45	62.6	78.3	$1*10^{-5}$
20	1	17.43	35.7	78.3	$2.7*10^{-5}$
25	0.641	17.45	24.6	78.3	$2.7*10^{-5}$
30	0.4463	17.45	18.7	78.3	$3.84*10^{-5}$
40	0.25	17.44	11.9	78.3	6.610^{-5}

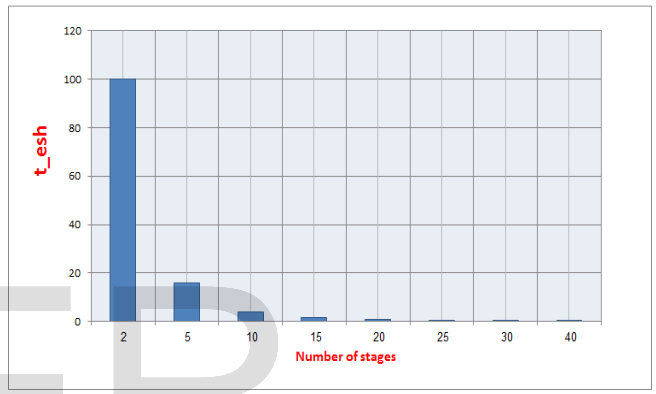

Fig. 3-The effect of increasing frac stages on the transient linear period.

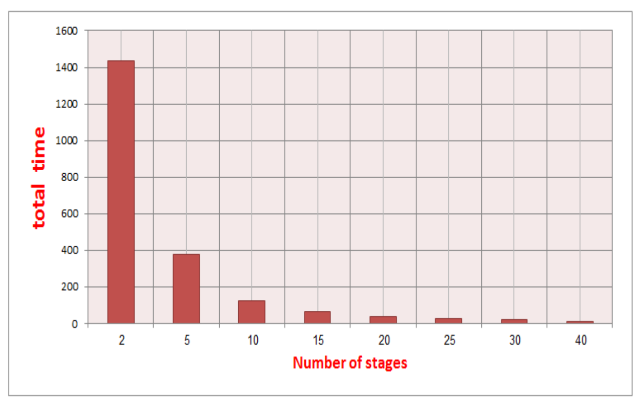

Fig. 4-The effect of inceasing frac stages on the total depletion time till economic limit is reached .

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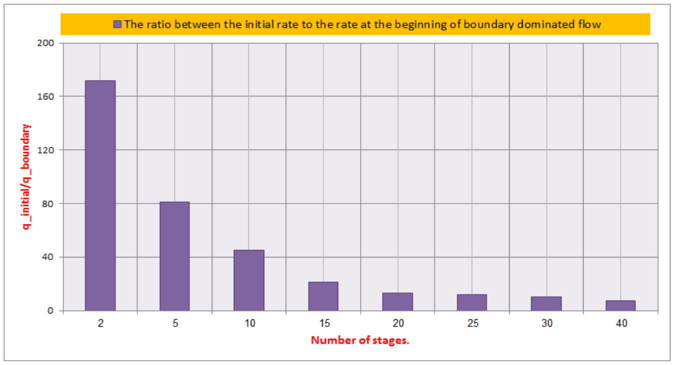

Fig. 5-The ratio between the initial rate to the rate at the beginning of the boundary dominated flow.

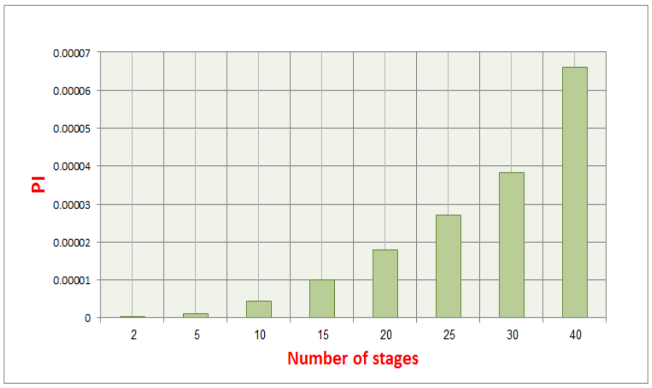

Fig. 6-The effect of increasing frac stages on the productivity index.

Increasing the number of stages, increases the cumulative production as shown in **Fig. 7** and **Fig. 4.8 . Fig. 4.9** is the percentage of production increase for n> 2 and n>15 after 14000 day of production . As shown in **Fig.4.9**, increasing the number of stages from n=2 to n=5,10,15 will result in a percentage of production increase of 60%, 73.6%, 75.5% while increasing the number of stages from n=2 to n=40 results in a percentage of production increased of 77%.Increasing the number of stages from n=15 to n=40 results in percentage of production increase of 5%. Similar results after 2000 day of production is shown in **Fig.4.10 .**

The number of stages should be economically optimum and determined in terms of the in situe conditions of the reservoir , the estimated ultimate recovery and the expected production period. **Fig. 11** is the percentage of production increase if the production period extended from 2000 to 14000 day .As shown from **Fig.11** that for n=2,5,10,15 extending the production period from 2000 to 14000 will result in a percentage of production increase of 60% ,58%,48%,35%while for n= 40 increasing the production period will result in average production increase of 3.8% .

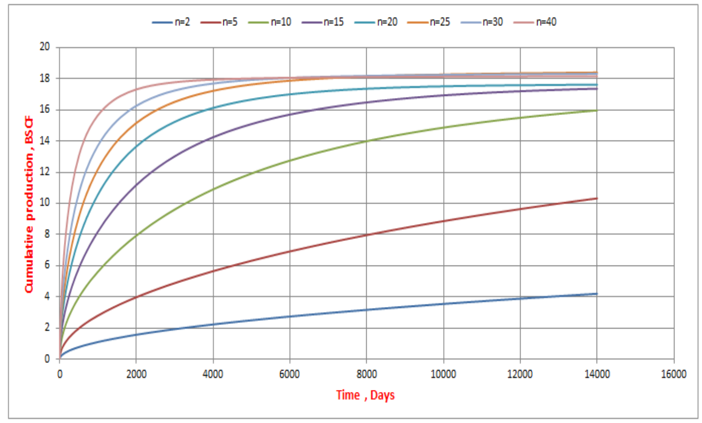

Fig. 7–The cumulative production with the time for different stages.

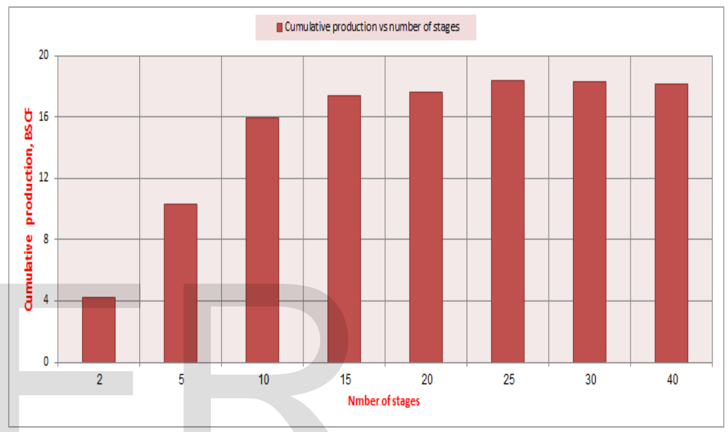

Fig. 8– The cumulative production different stages after 14000 day.

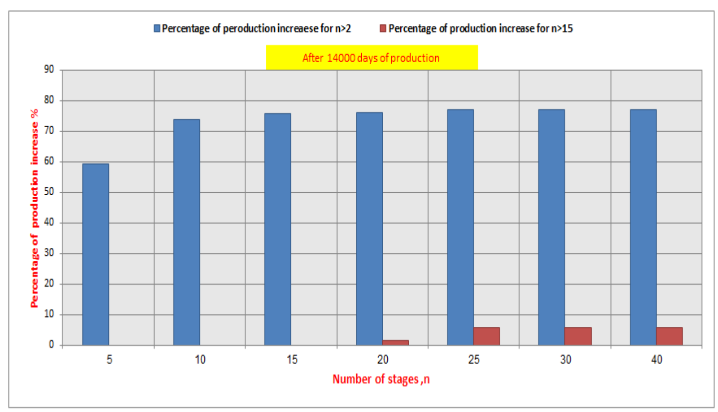

Fig. 9- The percentage of production increase for n> 2 and n>15 after 14000 day of production.

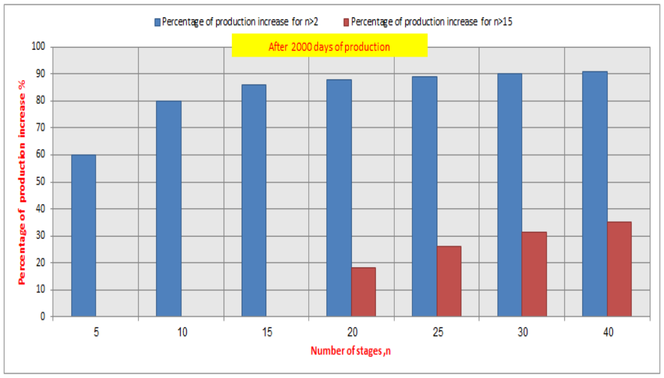

Fig. 10- The percentage of production increase for n> 2 and n>15 after 2000 day of production.

The number of stages should be economically optimum and determined in terms of the in situe conditions of the reservoir , the estimated ultimate recovery and the expected production period. **Fig. 11** is the percentage of production increase if the production period extended from 2000 to 14000 day .As shown from **Fig.11** that for n=2,5,10,15 extending the production period from 2000 to 14000 will result in a percentage of production increase of 60% ,58%,48%,35%while for n= 40 increasing the production period will result in average production increase of 3.8% .

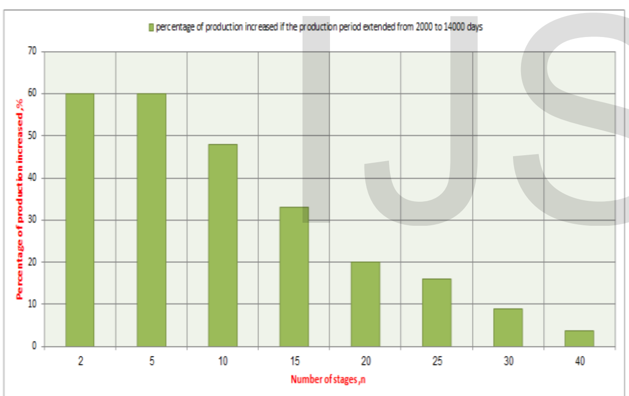

Fig. 11- Percentage of production increase if the production period extended from 2000 to 14000 day.

4. Effect of fracture face skin.

Fracture face skin is modeled in two different models as chocked fracture damage and fracture face damage.[1] Chocked fracture damage occurs when the region around the well bore has a reduced permeability. Choked fracture damage originates when the proppant within the fracture is embedded or crushed or lost as shown in Fig.12 Where $\boldsymbol{x_s}$,$\boldsymbol{k_s}$,$\boldsymbol{w_s}$ are the chocked fracture length , the permeability of the damaged zone and the width of the damaged zone respectively. Fracture face damage occurs due to the filtration of the fracturing fluid into the formation and formation of filter cake. Filtration and filter cake reduce the permeability in the region surrounding the frac as shown in Fig.4.13 . Different values of fracture face skin (0, 0.01, 0.02, 0.05, 0.07, 0.1, 0.2, 0.5, 0.7, 1) are used to study the impact of skin on the well performance. The data used for simulation is summarized in Table 3. As the fracture face skin increases, the linear flow regimes dimensioned gradually and look like another flow regimes. This is could lead to wrong analysis for the well performance and reservoir parameters estimated from wrong flow regime as shown in Fig. 14.

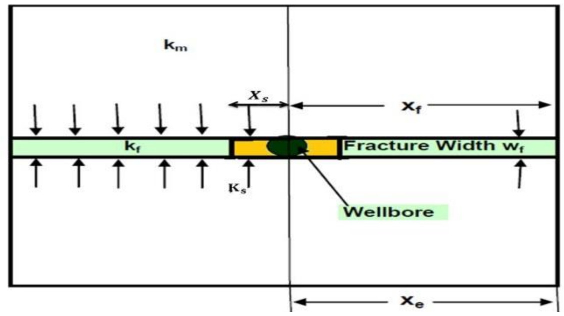

Fig. 12- Choked fracture damage from $\boldsymbol{Cinco-ley\ and\ samaneigo}$(1981).

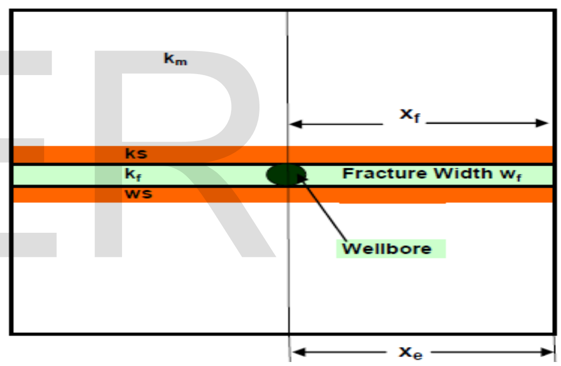

Fig. 13- Hydraulic fracture with fracture face damage from $\boldsymbol{Cinco-ley\ and\ samaneigo}$(1981) .

For small values of frac face skin i.e (s_{ff}=0.0. s_{ff}=0.01,s_{ff}=0.05, s_{ff}=0.1), the linear flow regime or half slope on log- log plot is changed at early time and the curves become more flatten but finally linear flow is reached or the half slope appears .The flatness of the curves may cause misinterpretation of the well performance during the early production period. The flat part of the curve indicates a transient radial flow which is completely incorrect. Other note is that, although the small values of skin change the shape of the production rate on the log-log plot, the total production time is nearly the same i.e. the curves are matched. For large values of skin (s_{ff}=0.5 ,s_{ff}=1), the linear flow regime doesn't appear on the log –log plot at all but complete transient radial and boundary flow appear on the log-log plot and the total production time increased

Table 3- The data used for simulating the effect of Skin on the well performance of gas unconventional reservoirs.

γ_g	0.7
T	$240\ F^{\circ} = 700\ R^{o}$
p_i	5000 psi
p_{wf}	1000 psi
h	300 ft
r_w	0.35 ft
c_f	$6*10^{-6}$
c_w	$3.6*10^{-6}$
s_w	0.4
$\emptyset$	0.1
k	0.01 md
x_f	500 ft
l_e	5000 ft

The straight line specialized plot of $\frac{[m(p_i)-m(p_{wf})]}{q_g}$ vs $\sqrt{t}$ for different values of skin is shown in **Fig.15** . As shown in **Fig.15** that the linear flow behavior still preserves its straight line shape which is a clear evident on the linear flow behavior but the effect of skin appears only as an intercept on y-axis .Increasing the skin will cause an increase in the intercept value. The straight lines representing different values of skin are parallel to each other but with different intercepts.

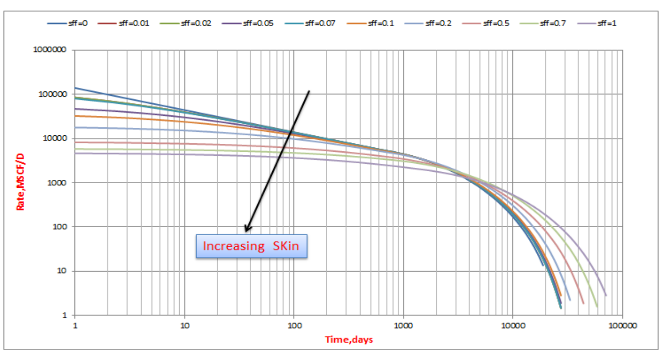

Fig. 14- The production rate for different skin values.

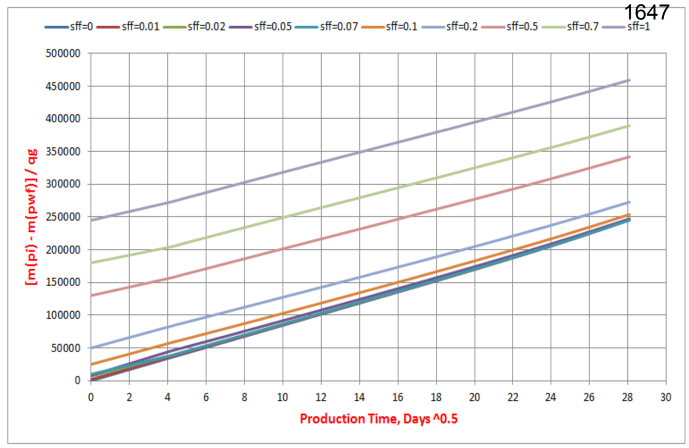

Fig. 15-Plot of $\frac{[m(P_i)-m(P_{wf})]}{q_g}$ vs $\sqrt{t}$ for different values of skin.

From the above , the frac face skin causes dramatic change on the log –log plot by masking the actual linear behavior to be like another flow regime .The linear flow still preserve its characteristic shape on the specialized plot of $\frac{[m(P_i)-m(P_{wf})]}{q_g}$ vs $\sqrt{t}$ as straight line so that interpretation of the actual production data may be completely incorrect if the analysis is limited to log-log plot till specialized plot of $\frac{[m(P_i)-m(P_{wf})]}{q_g}$ vs $\sqrt{t}$ is plotted. The cumulative production for different values of frac face skin is shown in **Fig.16** .

The percentage of production loss for different values of skin is shown in **Fig.17** In this case the impact of frac face skin is 7.6%, 14%, 44% and 60% production loss for frac face skin of 0.05,0.1,0.5 and 1, respectively.

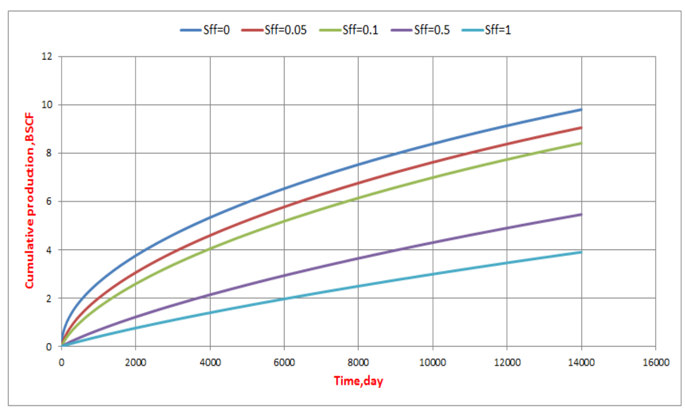

Fig. 16–The cumulative production vs.time for different values of frac face skin.

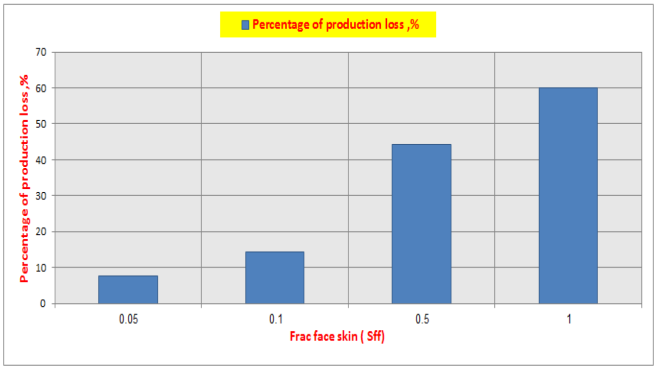

Fig. 17- Percentage of production loss for different values of frac face skin.

5. Effect of Production under different drawdown .

In this section, we will investigate the effect of production under different draw down on well performance of gas unconventional reservoirs. Two scenarios will be used to indicate the effect of the draw down on well performance of gas unconventional reservoirs. The first scenario used is performing the simulation cases under constant initial reservoir pressure while bottom hole flowing pressure changes for each case. During the production life of the reservoir ,the well may be shut down for several reasons so the second scenario is performing the simulation cases with different initial reservoir pressure while P_{wf} is constant. Finally performing the simulation cases under constant draw down but with different initial reservoir pressure and bottom hole flowing pressure i.e. $(P_i - P_{wf})$ is constant while P_i and P_{wf} aren't constants .

5.1 Production under different draw down while the initial reservoir pressure is constant.

In this case, different values of P_{wf} for each simulation case is used while initial reservoir pressure is constant. The data used for simulation is summarized in **Table 4.**

The straight line specialized plot of $\frac{[m(P_i)-m(P_{wf})]}{q_g}$ vs.$\sqrt{t}$ for the previous simulation cases is shown in **Fig. 18 .** As it is shown in **Fig. 18** that all the previous cases don't have the same slope m_{cp} as obtained from the analytical solution. This indicate that linear flow analysis is greatly affected by the drawdown.

To demonstrate this effect *Ibrahim and Wattenberger (2005)*[2]defined a dimensionless draw down parameter defined as :

$$D_D = \frac{[m(p_i)-m(p_{wf})]}{m(p_i)} \qquad (6)$$

Then defined correction factor for correcting the slope of straight line as:

$$f_c = 1-0.0852D_D-0.0857{D_D}^2 \qquad (7)$$

To indicate the importance of the correction factor defined in Eq. 7 a plot of $\frac{[m(P_i)-m(P_{wf})]}{q_g}$ vs. $f_c\sqrt{t}$ is shown in **Fig.19** .The correction factor normalize the different slopes straight lines shown in **Fig. 18** into only one straight line with constant slope in **Fig. 19** Linear analysis without using the correction factor will result in an over estimation of the calculated reservoir parameters as fracture half-length , $\sqrt{k}A_c$ and *OGIP.*

Table 3- The data used for simulating the effect of production under differentp_{wf} on the well performance through gas unconventional reservoirs.

γ_g	0.7
T	$240\ F^{\circ} = 700\ R^{o}$
p_i	5000 psi
h	300 ft
r_w	0.35 ft
c_f	$6*10^{-6}$
c_w	$3.6*10^{-6}$
s_w	0.4
Ø	0.1
k	0.01 md
x_f	500 ft
f_c	1000 md-ft
l_e	5000 ft
w	1000 ft

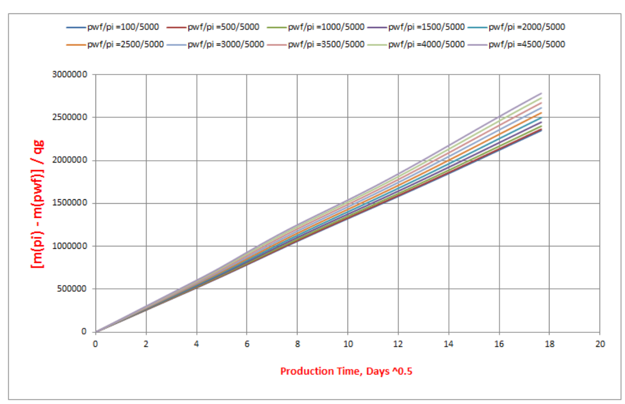

Fig. 18- Plot of $\frac{[m(P_i)-m(P_{wf})]}{q_g}$vs $\sqrt{t}$ for the different values of p_{wf} at constant p_i =5000 psi.

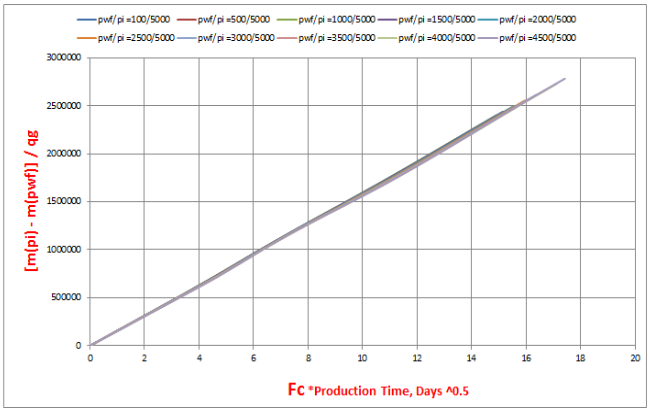

Fig. 19- $\frac{[m(P_i)-m(P_{wf})]}{q_g}$**vs** $f_c\sqrt{t}$ **for the different values of** p_{wf} **at constant** p_i **=5000 psi.**

5.2 Production under constant p_{wf} while the initial reservoir pressure isn't constant .

Different scenario to indicate the effect of production under different draw down while the initial reservoir pressure is not constant but p_{wf} is constant. During the production period the well may be shut for different reasons but when the production is continued the reservoir pressure may be not at the initial reservoir pressure during the initial production period. To show the effect of production under different initial reservoir pressure different simulation cases are run with constant p_{wf}. The input data used to run these simulation cases is the same data in **Table 4** but with p_{wf}=2000 psi and p_i=6000,5000,4000,3000 and 2500 psi.

A plot of $\frac{[m(P_i)-m(P_{wf})]}{q_g}$vs.$f_c\sqrt{t}$ is shown in **Fig. 20.** As shown in **Fig. 20** that different straight lines with different slopes is obtained for different p_i.The reason for these different slopes straight lines is the reservoir and fluid pressure dependent properities $\sqrt{(\emptyset\mu_g c_t)_i}$. To obtain a single straight line with constant slope it is preffered to plot $\frac{[m(P_i)-m(P_{wf})]}{q_g}$ $vs.\frac{f_c}{\sqrt{(\emptyset\mu_g c_t)_i}}\sqrt{t}$ or $\sqrt{(\emptyset\mu_g c_t)_i}\frac{[m(P_i)-m(P_{wf})]}{q_g}$ $vs.f_c\sqrt{t}$ to eleminate the effect of the pressure dependent properities and obtaining a single straight line with constant slope as shown in **Fig.21.**

6. The effect of Production from different drainage area on well performance

In this section we will study the effect of production from different drainage areas on well performance of gas unconventional reservoirs . This effect will be studied by assuming that the horizontal well isn't completely penetrate the reservoir .Assuming different horizontal well lengthes (l_e) with constant number of stages.In the previous study of the impact of different fracture stages we assumed a constant

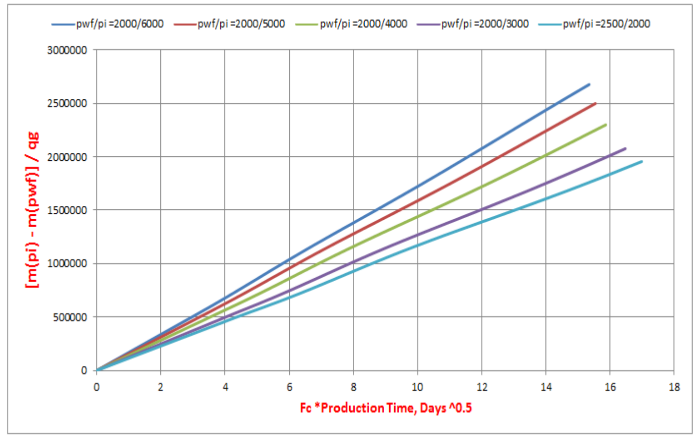

Fig. 4. 20-Plot of $\frac{[m(P_i)-m(P_{wf})]}{q_g}$**vs** $f_c\sqrt{t}$ **for the different values of** p_i **at constant** p_{wf} **=2000 psi.**

The slope of the straight line in **Fig.4.31** is $m_{cp}=\frac{315.4327T}{\sqrt{k}x_e h}$ which is constant for the same reservoir because it doesn't include any pressure dependent properties. This slope can be used for the straight line analysis to obtain the different reservoir and frac properties.

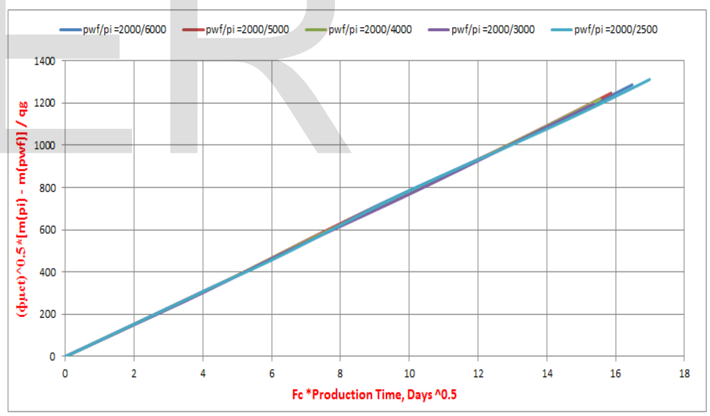

Fig. 21-Plot of $\sqrt{(\emptyset\mu_g c_t)_i}\frac{[m(P_i)-m(P_{wf})]}{q_g}$ $vs\ f_c\sqrt{t}$**for the different values of** p_i **at constant** p_{wf} **=2000 psi.**

reservoir length but the number of stages was variable. The data used for simulationg the effect of different drainage areas is summerised in **Table 5**.The well length is changed in each simulation case (l_e =1000, 2000, 3000, 4000 and 5000 ft). The effect of different drainage areas or frac spacing on the well performance can be illustrated by plotting all the previous cases on the same log log plot as shown in **Fig. 22.**

Table 4- The data used for simulating the effect of production from different drainage areas on the well performance of gas unconventional reservoirs.

γ_g	0.7
T	$240\ F^{\circ} = 700\ R^{o}$
p_i	5000 psi
h	300 ft
r_w	0.35 ft
c_f	$6*10^{-6}$
c_w	$3.6*10^{-6}$
s_w	0.4
$\emptyset$	0.1
k	0.001 md
x_f	500 ft
f_c	1000 md-ft
w	1000 ft

As shown in **Fig. 4.22**, the plots for the different cases overlaps each other until the transient linear period is finished. Since the reservoir properties and the fracture half-length are the same in all these simulated cases so that they have the same slope on the straight line specialized plot of $\frac{[m(P_i)-m(P_{wf})]}{q_g}\ vs. \sqrt{t}$. **Table 6** and **Fig. 23** summarize the calculated time to the end of transient linear for each case.

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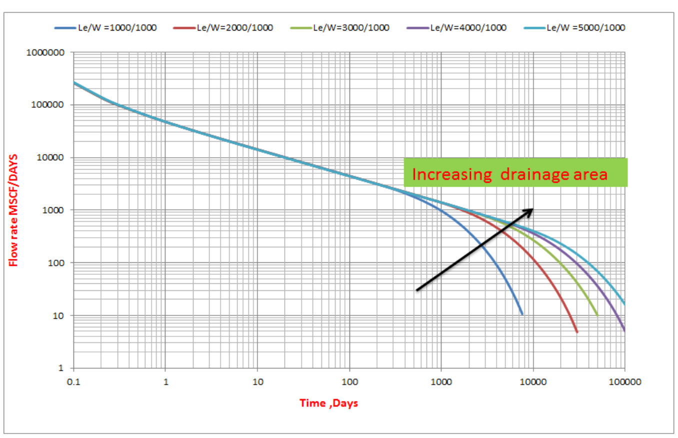

Fig. 22 - Log log plot of the previous simulated cases under different drainage areas .

Table 5 -The time to the end of transient linear for each case

Case	*Frac spacing* $2y_e$ *ft*	t_{ehs} *days*
1	*333.3*	*260*
2	*666.67*	*1040*
3	*1000*	*2340*
4	*1333.3*	*4160*
5	*1666.67*	*6500*

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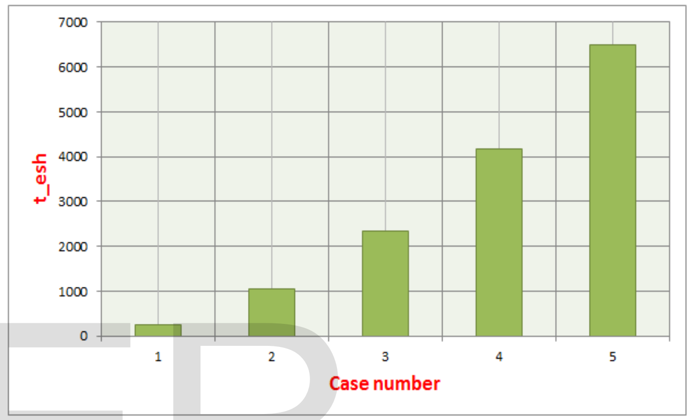

Fig. 4. 23- The time to the end of transient linear flow period for each case.

7. Conclusions.

The major conclusions of this work can be summarized as follows:

1. Well performance of gas un conventional reservoirs is greatly affected by the completion configuration between the horizontal well and reservoir.
2. Increasing the number of stages not only causes a rapid depletion of the reservoir but also result in a decrease in the time to the end of half slope period.
3. A decrease in the time to the end of transient linear regime makes performing (RTA) analysis difficult to be performed.
4. The number of stages should be economically optimum and determined in terms of the in situe conditions of the reservoir , the estimated ultimate recovery and the expected production period

5. Interpretation of the actual production data may be completely incorrect if the analysis is limited to log-log plot as the fracture face skin masks the actual linear behavior to be like another flow regimes so

the straight line specialized plot is required for proper interpretation as the skin appears only as an intercept on y-axis .

6. RTA is a draw down dependent analysis so that performing RTA without the use of the correction factor developed by *Ibrahim and wattenberger* would result in over estimation of the reservoir properties.
7. The length of the horizontal well throught out the reservoir only results in an increase in the time of the end of transient linear flow but has no effect on the straight line specialized plot .

8. NOMENCLATURE

x_e= half width of the reservoir, ft

x_f= frac half length ft

y_e= half distance between two successive fracs ,ft

p_{wD}= dimensionless pressure

t_{Dxe}= dimensionless time based on half width of the reservoir

t_{Dye} =dimensionless time based on half distance between two successive fracs

q_D= dimensionless rate

m_{wD} = dimensionless pseudo pressure

$m(p_i)$= pseudopressure at initial reservoir pressure, psi^2/cp

$m(p_{wf})$ = pseudopressure at bottom hole flowing pressure ,psi^2/cp

q_g= gas flow rate, MSCF/D

T= reservoir tempreture,R^o,F^o

K= reservoir permeability , md

c_t= total compressibility, psi^{-1}

μ_g= gas viscosity, cp

∅= porosity

m_{cR} =slope in case of constant rate

m_{cp}=slope in case of constant pressure

h= reservoir thickness , ft

A_c = cross sectional area to the flow, ft^2

t_{esh} = time to the end of half slope period ,Day

v_p= pore volume ft^3

$OGIP$ = original gas in place,BSCF.

B_{gi} = gas formation volume factor at initial reservoir pressure ,RB/STB

l_e = reservoir extension, ft

9. REFERENCES

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