

Buildup Test Analysis in Naturally Fractured Oil Reservoir

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Abstract: Naturally fractured reservoirs have a significant share of the world's hydrocarbon resources however, they represent one of the most daunting challenges reservoir engineers can deal with. This paper presents how to identify and model the naturally fractured reservoirs (Dual porosity model) using the results of the build-up test. The paper starts by giving an overview on the meaning of naturally fractured reservoir then, the main objectives of the well-tests on this type of reservoirs including the main procedures of these tests after that, third section includes the mathematical formulations governing these tests. Three case studies are analyzed. One of these cases is analyzed using one of the industrial software which is called Ecrin (Saphir). The other two cases are analyzed using a spread sheet program which is developed for analyzing buildup test data from naturally fractured reservoir.

Keywords: Fractured Reservoir – Buildup Test – Dual Porosity – Interporosity flow – Storativity.

1. INTRODUCTION

Naturally fractured reservoirs (NFR) are considered one of the most common encountered heterogeneous reservoirs in the world [1]. These reservoirs have two main classes that may be detected in such reservoirs, in case of the fractures are trending in a single direction so, the reservoir would have as anisotropic permeability (i.e. the permeability is direction-dependent) the other trend can be the Dual porosity where the reservoir can be classified into two regions: matrix which has relatively high porosity and low permeability values, fissures that have relatively low capacity and permeability values[2]. Warren and Root presented the reservoir as shown in Figure 1, assuming that the fluid flow from the blocks to the fracture is in a Pseudo steady state form then fluids flow from the fractures to the wellbore[3]. Kazemi used a similar model but without a pseudo steady state restriction however both gave similar results as shown in Figure 2[4]. Warren and Root defined two main characteristics of the NFR which are storativity ratio(ω) and interporosity flow parameter (λ) [3].

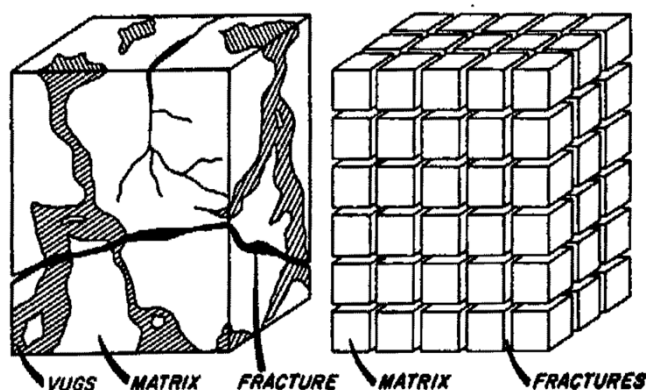


Figure1. Warren and Root model for NFR

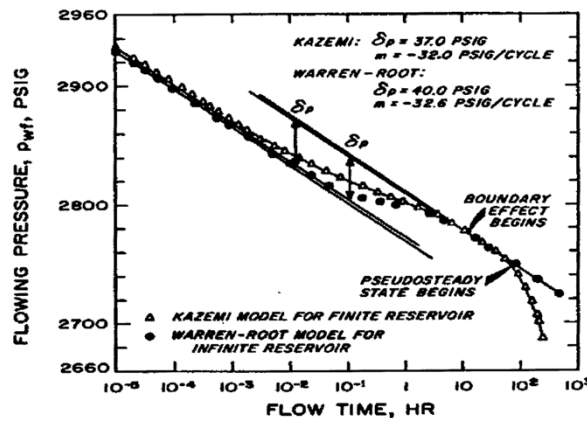


Figure2. Warren-Root and Kazemi results upon Draw down test data

1.1. Test Objectives Relevant to NFR

1.1.1. Naturally Fractured Reservoirs Identification

Warren and root[3] were the pioneer in proposing an identification method of dual porosity reservoirs, this type of reservoir have a significant form in semi-log plots as it contains two straight lines that have the same slope with a transition zone in between as shown in Figure 3 which represents a draw down test, the first straight line from the left represents the radial flow from the fissures as it has higher permeability than the matrix after a period the pressure in the fissures starts to decline at that point a pressure support come from the matrix to slow down the pressure decline as shown in the transition zone then the whole system starts to decline by the same rate. the same for buildup test as shown in the Figure 4, in case of plotting the shutting pressure versus Horner ratio, the second curve will be used to find the false pressure by extrapolation besides the skin factor, where the vertical displacement between the two parallel lines will be used to calculate the storativity ratio [5, 6].

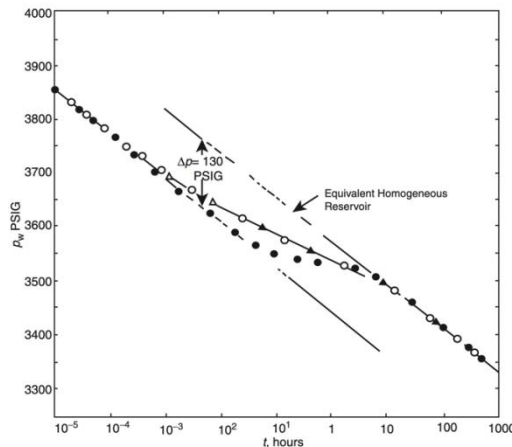


Figure3. Dual porosity reservoir Drawdown test

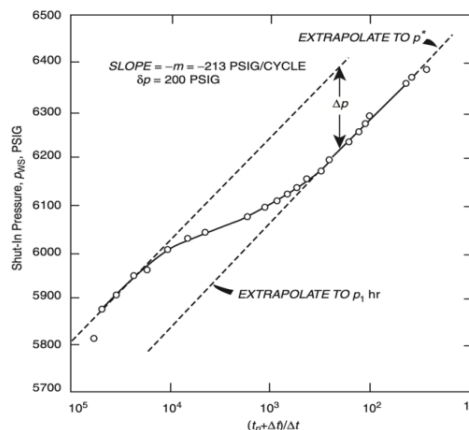


Figure4. Dual porosity reservoir Build-up test

2. TYPE CURVE

Type curve is a valuable tool for interpretation of production and pressure data as it is a log-log curve where the model itself presented in a dimensionless and constant operating conditions form, Fetkovitch was a pioneer in this field as he built his type curves using Arps decline equations by making them dimensionless by defining q_{DD} by dividing $q(t)$ over q_i -normalizing- and $t_{dd} = D_i \cdot t$, so now in calculating production rate at any time $q = q_i e^{-D_i t}$ then, when substituting in first 2 equations in the last one D_i and q_i will be cancelled and the equation will be in a form of $q_{dd} = e^{-t_{dd}}$, what he did here is just making the equation more generic as now instead of needing single exponential curve for each set of initial decline rate and initial rate now it is just one and we have only to match our data to it but, its drawback is, it did not consider the b factor in it [7]. Bourdet and Gringarten(1980) stated that, semi-log plots is not sufficient for identifying dual-porosity reservoirs due to the similarity of the pressure behavior to its behavior in case of stratified reservoirs, where in log-log plot, naturally fractured reservoirs seem like S-shaped curve and if we divided it to three sections, the first section in the plot will represent the flow from the fissures into the well then the pressure support due to the flow from the matrix to the fissures till pressure equalization and fluid flows from the whole system and the drawbacks of this technique appear in case of highly damaged reservoir as pressure behavior can be erroneously diagnosed as homogenous reservoir besides, in case of irregularly bounded well drainage systems the pressure behavior takes the S-shaped curve. Based on these drawbacks, Gringarten and Bourdet built two sets of pressure derivative type curves, the first one assumed pseudo steady state interporosity flow as shown in Figure 5 where the second type curve assumed transient interporosity flow as shown in Figure 6. They defined a set of independent controlling variables which are dimensionless pressure (P_D), dimensionless time (t_D), dimensionless wellbore storage (C_D), Storativity ratio (ω), $C_D \exp(2s)$, $\lambda \exp(-2s)$, - s: skin factor[8,9].

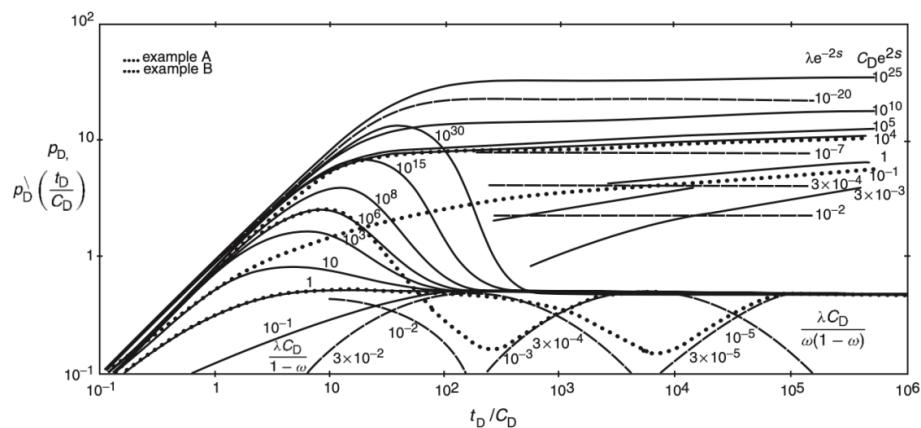


Figure5. First type curve

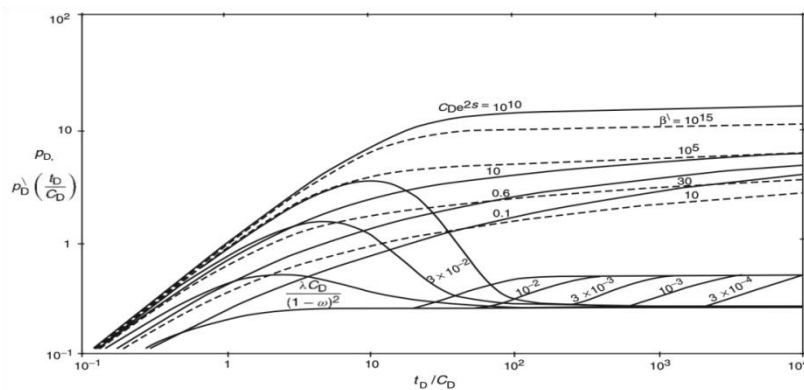


Figure6. Second type curve

3. MATHEMATICAL FORMULATIONS

3.1. Geometry Factor α

Geometric factor of the matrix blocks on the fluid flow between fracture/matrix that depends on the shape and size of matrix blocks[10-12]

$$\alpha = \frac{n(n + 2)}{L^3} \quad (1)$$

Shape factor (n) indicates to the directions available of the fluid to exchange between the matrix and the fracture. The higher the shape factor, the easier the exchange. The smaller the characteristic length of the matrix blocks (L), the easier the exchange.

$$L = \frac{\text{volume of matrix block}}{\text{area of the matrix block}} \times n \quad (2)$$

The geometric factor can also be calculated from the following expression:

$$\alpha = \frac{A}{Vx} \quad (3)$$

Where:

A: surface area of the matrix block, ft²

V = volume of the matrix block

x = characteristic length of the matrix block, ft

3.2. Porosity

Porosity is the ratio of the void volume to the total volume of the rock.

Matrix porosity [13]:

$$\phi_m = \frac{\text{void volume of the matrix}}{\text{total volume of rock sample}}$$

Fracture porosity:

$$\phi_m = \frac{\text{void volume of the fracture}}{\text{total volume of rock sample}}$$

3.3. Storage Capacity

Storage capacity is the amount of fluid that can be stored in the system voids volume[14].

Capacity of the matrix:

$$C_m = \phi_m V_m c_{tm} \quad (4)$$

Capacity of the fracture:

$$C_f = \phi_f V_f c_{tf} \quad (5)$$

Capacity for the whole reservoir:

$$C_{f+m} = \phi_m V_m c_{tm} + \phi_f V_f c_{tf} \quad (6)$$

Matrix compressibility:

$$c_{tm} = c_o S_o + c_w S_w + c_{pm} \quad (7)$$

Fracture compressibility:

$$c_{tf} = c_o S_o + c_w S_w + c_{pf} \quad (8)$$

For each system there is a corresponding dimensionless wellbore storage:

$$C_{DF+m} = \frac{\beta C}{C_{f+m} h r_w^2} \quad (10)$$

Where $\beta = \frac{1}{2} \pi$ in SI units, $\beta = 0.89$ in US units

3.4. Storativity Ratio

Storativity ratio (ω): is the ratio of fracture capacity to the total formation capacity. Storativity ratio ranges between 0.1 to 0.001 and can be expressed as [15, 16].

$$\omega = \frac{C_f}{C_{f+m}} \quad (11)$$

The smaller the ω , the higher the dip in the diagnostic plot (high pressure variation). At $\omega = 1$ the reservoir seems to be homogenous.

Storativity ratio can also be expressed as:

$$\omega = 10^{(-\Delta p/m)} \quad (12)$$

Where:

m: the semi-log line slope

Δp : the vertical distance between the two parallel lines

3.5. Interporosity Flow Coefficient (λ)

Interporosity flow coefficient or internal flow coefficient is a measure of the ability of fluids to flow from the matrix to the fracture [17,18].

$$\lambda = \alpha r_m^2 \frac{k_m}{k_f} \quad (13)$$

The larger the interporosity flow coefficient, the easier the exchange where lower λ delays the start of the transition period. The value of λ ranges from 10^{-4} to 10^{-8} .

Interporosity flow coefficient can also be expressed as:

For draw-down test

$$\lambda = \frac{\omega}{1-\omega} \times \frac{(\phi h c_t)_m \mu r_w^2}{1.781 k_f t_1} = \frac{1}{1-\omega} \times \frac{(\phi h c_t)_m \mu r_w^2}{1.781 k_f t_2} \quad (14)$$

For buildup test

$$\lambda = \frac{\omega}{1-\omega} \times \frac{(\phi h c_t)_m \mu r_w^2}{1.781 k_f t_p} \left(\frac{t_p + \Delta t}{\Delta t} \right)_1 = \frac{1}{1-\omega} \times \frac{(\phi h c_t)_m \mu r_w^2}{1.781 k_f t_p} \left(\frac{t_p + \Delta t}{\Delta t} \right)_2 \quad (15)$$

3.6. Dimensionless Factors

To enter the type curve to find the best match for the data requires using some dimensionless quantities such as the following [19, 20]:

Dimensionless pressure

$$p_D = \left[\frac{k_f h}{141.2 Q B \mu} \right] \Delta p \quad (16)$$

Dimensionless time

$$t_D = \frac{0.0002637 k_f t}{[(\phi \mu c_t)_f + (\phi \mu c_t)_m] \mu r_w^2} \quad (17)$$

Interporosity Dimensionless group

$$\beta \lambda = \delta \left[\frac{(C_D e^{2s})_{f+m}}{\lambda e^{-2s}} \right] \quad (18)$$

Where:

$\delta = 1.0508$ for spherical blocks

$\delta = 1.8914$ for slab matrix blocks

4. CASE STUDIES

4.1. First Case: Analyzing Buildup Test Data for an Infinite Conductivity Fractured Well

Table (1) shows pressure buildup data for an infinite conductivity fractured well. Before shutting the test, the well has produced with a constant production rate of 419 STB/day for 7800 hours. The initial reservoir pressure is 3700 psia. The crude oil has a viscosity of 0.65 cp and oil formation volume factor of 1.266 bbl/STB. The oil compressibility equals 0.000021 1/psi. The wellbore radius is 0.28 feet. The formation has a porosity of 12 % and net pay thickness of 82 feet.

Table1. Pressure buildup test data

Δt , hour	P_{ws} , psi	Δt , hour	P_{ws} , psi
0.083	3420	10	3500
0.167	3431	12	3506
0.25	3435	24	3528
0.5	3438	36	3544
0.75	3444	48	3555
2	3463	60	3563
3	3471	72	3570
4	3477	96	3582
5	3482	120	3590
6	3486	144	3600
7	3490	192	3610
8	3495	240	3620
9	3498		

Firstly, it is required to calculate the Horner ratio as presented in Table 2 using the following expression:

$$\frac{t_p + \Delta t}{\Delta t} \tag{19}$$

Table2. Calculation of Horner ratio

Δt , hour	Horner Ratio	Δt , hour	Horner Ratio
0.083	93976.90	10	781.00
0.167	46707.59	12	651.00
0.25	31201.00	24	326.00
0.5	15601.00	36	217.67
0.75	10401.00	48	163.50
2	3901.00	60	131.00
3	2601.00	72	109.33
4	1951.00	96	82.25
5	1561.00	120	66.00
6	1301.00	144	55.17
7	1115.29	192	41.63
8	976	240	33.50
9	867.67		

Then, plot the pressure versus Horner ratio on semi log scale as shown in Figure 7.

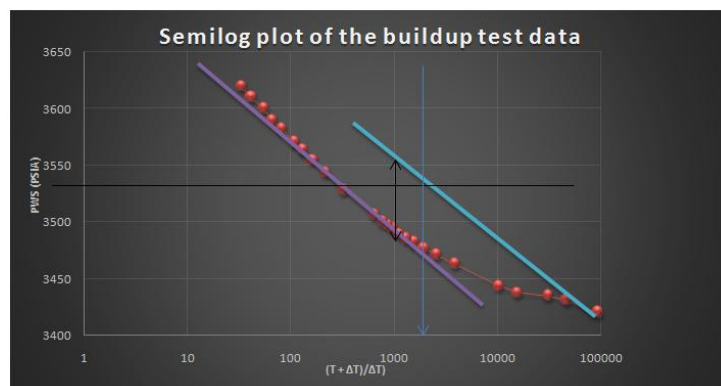


Figure7. Horner plot for Case 1

4.1.1. Analyzing Well Test Data for Case 1:

The top line in Figure 7 represents the fissure trend which has a higher permeability, while the bottom line represents matrix trend which will be the system trend after producing all oil in the fracture (fissure) zone and has lower permeability.

The transitional zone between two lines refers to the pressure declining in the fracture. The declining happens because the well is producing the oil inside the fracture in a higher rate than the matrix.

The slope of these two lines represents (m) which is used to calculate the formation flow capacity ($K_f h$) from the following expression:

$$K_f h = \frac{162.6 Q B \mu}{m} \tag{20}$$

The vertical distance between the two lines represents (Δp) which is needed to calculate Storativity ratio (ω) using Eq. 12.

The results show that:

The formation flow capacity = 1594.23 md.ft

The fracture permeability = 19.44 md.

Storativity ratio (ω) = 0.000518

Internal flow coefficient (λ) = 7.80196×10^{-8}

4.2. Second Case

Table 3 shows the buildup test pressure derivative for a naturally fractured reservoir.

Before shutting the test, the well has a constant production rate of 960 STB/day for a period of time. The crude oil has a viscosity of 1cp and oil formation volume factor of 1.28bbl/STB. The oil compressibility equals 0.000001 1/psi. The wellbore radius is 0.29 feet. The formation has a porosity of 0.7 % and net pay thickness of 36 feet.

Table3. *Buildup test pressure derivative*

Δt , hours		Δt , hours	
0.00348888	11.095	0.49238	48.791
0.00904446	20.693	0.54793	49.7
0.0146	25.4	0.60349	50.541
0.0201555	28.105	0.6646	51.305
0.0257111	29.978	0.7146	51.939
0.0312666	31.407	0.77015	52.589
0.0368222	32.499	0.82571	53.208
0.0423777	33.386	0.88127	53.796
0.0479333	34.096	0.93682	54.4
0.0590444	35.288	0.99238	54.874
0.0701555	36.213	1.0479	55.447
0.0812666	36.985	1.1035	55.875
0.0923777	37.718	1.2146	56.845
0.10349	38.33	1.3257	57.686
0.12571	39.415	1.4368	58.343
0.14793	40.385	1.5479	59.054
0.17016	41.211	1.659	59.726
0.19238	41.975	1.7702	60.345
0.2146	42.64	1.8813	60.949
0.23682	43.281	1.9924	61.476
0.25904	43.969	2.1035	61.995
0.28127	44.542	2.2146	62.477
0.30349	45.085	2.4368	63.363
0.32571	45.658	2.6924	64.303
0.38127	46.804	2.9146	64.983
0.43682	47.836	3.1368	65.686
		3.359	66.229

It is reported that the well was opened to flow at a rate of 2952 STB/day for 1.33 hours, shut-in for 0.31 hours, opened again at the same rate for 5.05 hours, closed for 0.39 hours, opened for 31.13 hours at the rate of 960 STB/day, and then shut-in.

Before calculating Horner ratio, it is required to calculate the total produced oil (N_p) and production time (t_p).

$$N_p = \frac{2952}{24} \times (1.33 + 5.05) + \frac{960}{24} \times 31.13 = 2030 \text{ STB}$$

$$t_p = \frac{24 \times 2030}{960} = 50.75 \text{ day}$$

Then, Horner ratio is calculated as presented in Table 4.

Table4. Pressure buildup test data (Case 2)

Δt , hours	Horner Ratio	Δt , hours	Horner Ratio
0.00348888	14548.219	0.49238	104.07791
0.00904446	5612.5567	0.54793	93.627708
0.0146	3477.2671	0.60349	85.099985
0.0201555	2519.0968	0.6646	77.366988
0.0257111	1974.9918	0.7146	72.02365
0.0312666	1624.2497	0.77015	66.900799
0.0368222	1379.3397	0.82571	62.466496
0.0423777	1198.6464	0.88127	58.591317
0.0479333	1059.8359	0.93682	55.176363
0.0590444	860.58194	0.99238	52.143211
0.0701555	724.44292	1.0479	49.433534
0.0812666	625.53087	1.1035	46.993203
0.0923777	550.4129	1.2146	42.786185
0.10349	491.41936	1.3257	39.284303
0.12571	404.73479	1.4368	36.323984
0.14793	344.09133	1.5479	33.788617
0.17016	299.26928	1.659	31.592827
0.19238	264.819	1.7702	29.671054
0.2146	237.5028	1.8813	27.977888
0.23682	215.31256	1.9924	26.473549
0.25904	196.9292	2.1035	25.12812
0.28127	181.44406	2.2146	23.917683
0.30349	168.23286	2.4368	21.82793
0.32571	156.8242	2.6924	19.850654
0.38127	134.11695	2.9146	18.413539
0.43682	117.18859	3.1368	17.180024

Then, the pressure is plotted versus Horner ratio on a semi log scale as shown in Figure 8.

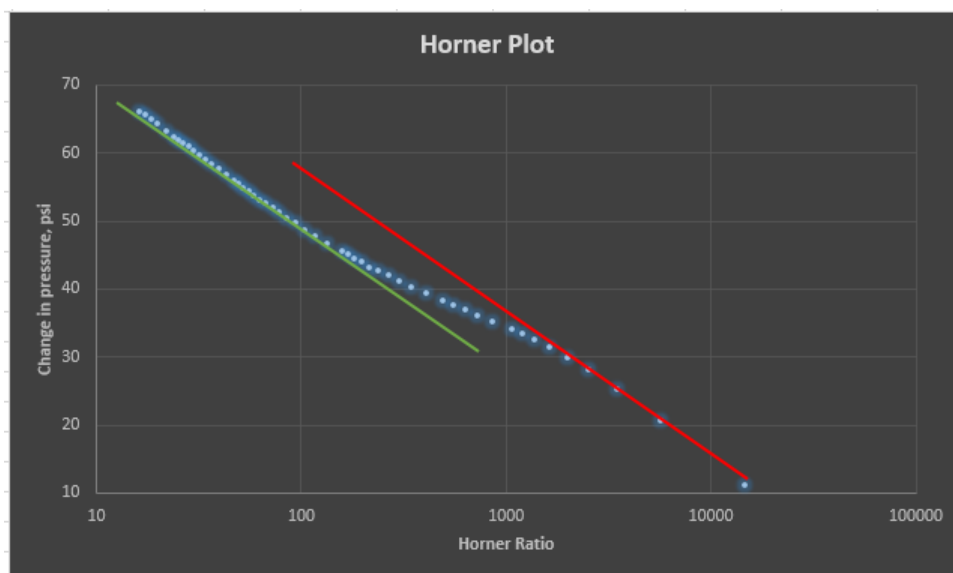


Figure8. Horner plot for naturally fractured reservoir

In this paper, plotting the change in pressure versus time as shown in Figure 9 is presented to analyze the well test data of naturally fractured reservoir.

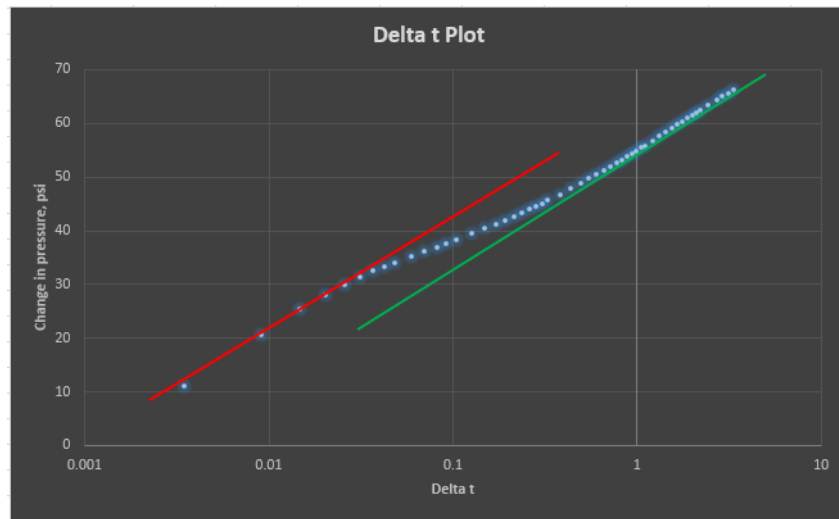


Figure9. Delta t plot for Figure 8 Horner plot for naturally fractured reservoir

As shown in Figures 8 and 9, the red line represents the fissure trend which has a higher permeability, while the green line represents matrix trend which will be the system trend after producing all oil in the fracture (fissure) zone and has lower permeability.

The transitional zone between two lines refers to the pressure declining in the fracture. The declining happens because the well is producing the oil inside the fracture in a higher rate than the matrix.

From Figure 8, The slope of the two parallel straight lines can be calculated as:

$$m = \frac{38 - 17}{\log(1000) - \log(10000)} = 21 \text{ psi/cycle}$$

The vertical distance between the two lines represents $\Delta p = 59 - 50 = 9 \text{ psi}$.

From Figure 9, The slope of the two parallel straight lines can be calculated as:

$$m = \frac{43 - 22}{\log(0.1) - \log(0.01)} = 21 \text{ psi/cycle}$$

The vertical distance between the two lines represents $\Delta p = 43 - 33 = 10 \text{ psi}$.

The derivative function and delta P are plotted versus equivalent time as shown in Figure 10.

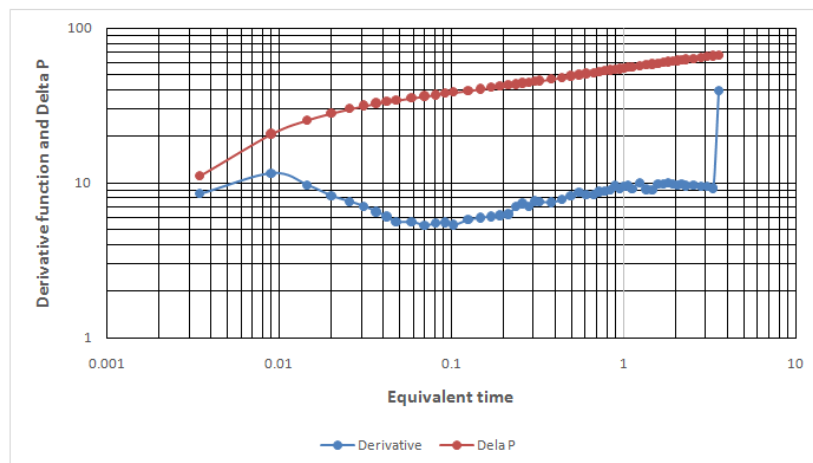


Figure10. Derivative function and delta P for naturally fractured reservoir

Flow capacity = 9195.848md.ft.

Fracture permeability = 255.44md.

$\omega = 0.018$

$\lambda = 6.86 \times 10^{-6}$

4.3. Third Case

Figure 11 represents the diagnostic plot of case-3 where the green curve represents the pressure change and the red one represents the pressure derivative which takes a S-shaped that indicates a naturally fractured reservoir, both curves are plotted against the elapsed time. The main use of the diagnostic plots is to define the flow regimes throughout the reservoir, the first note, the unit slope at the early time region indicates a wellbore storage effect that can be due to, all the production is from the fluid expansion in the well not from the reservoir in case of Drawdown test and for fluid compression in case of buildup test. Since there is no good match for the actual data with the model as shown in Figure 11, skin factor which is presented in Figure 12 should be changed to get good match.

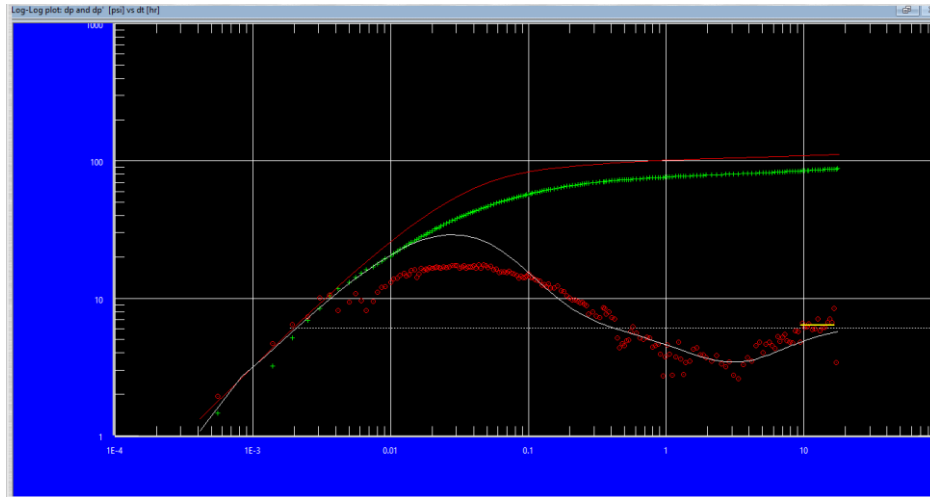


Figure11. First trial to match the diagnostic plot for Dual porosity model using Ecrin software (Case 3)

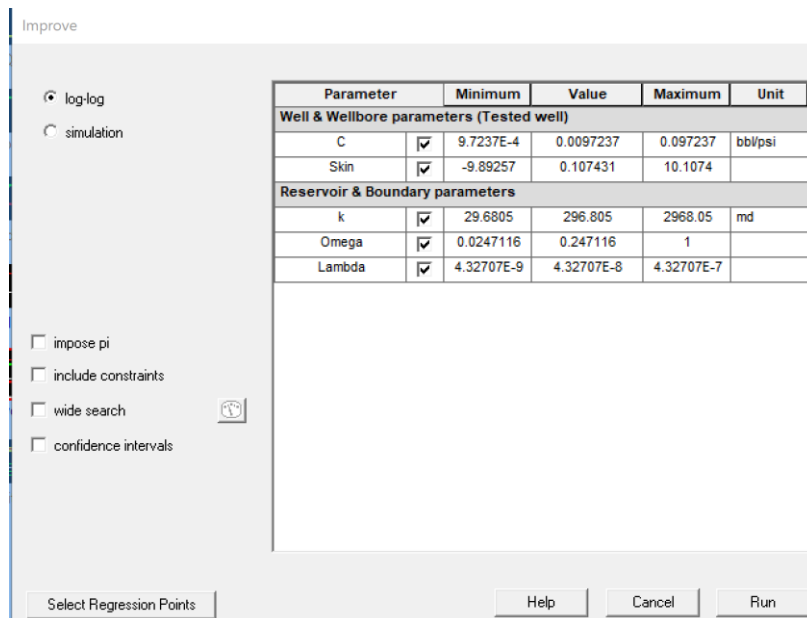


Figure12. First trial to find the best model

After modifying the skin factor, a good match was obtained as shown in Figure 13 and the results are presented in Figure 14. The first anticipated straight line that indicates a radial flow from the fracture to the wellbore is not deductible and only single straight line will appear in the semilog plot due to quick support from the matrix to the fracture that can be due to lower ω and/or higher λ so the matrix permeability is relatively high or due to high damage by skin or wellbore storage effect.

Due to the pressure support from the matrix to the fracture which takes a form of decrease in the pressure drop till reaching an equalization between the matrix and fracture pressures which is represented by the dip -transition zone- then after that, both systems will act like a single homogenous system with a radial fluid flow as the straight line implies however, in this case no boundary has been detected may be due to reservoir low permeability or not enough test time.

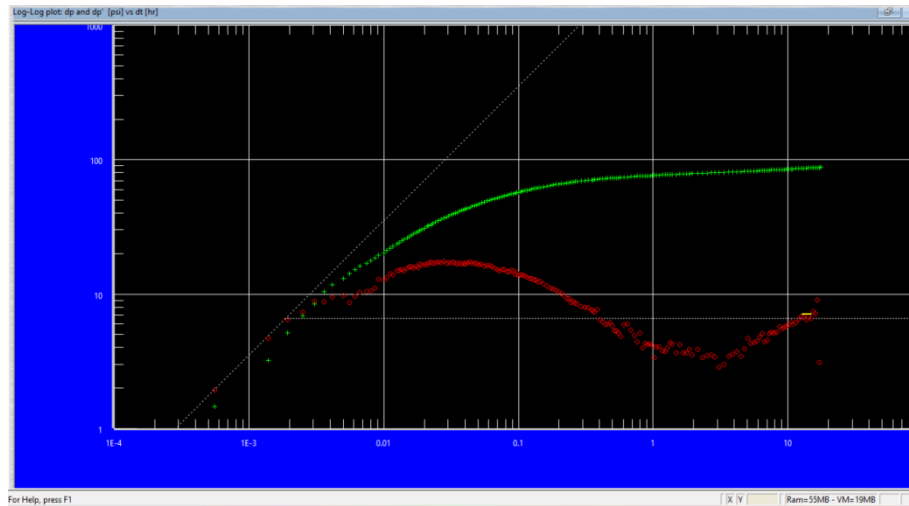


Figure13. Diagnostic plot for Dual porosity model using Ecrin software (Case 3)

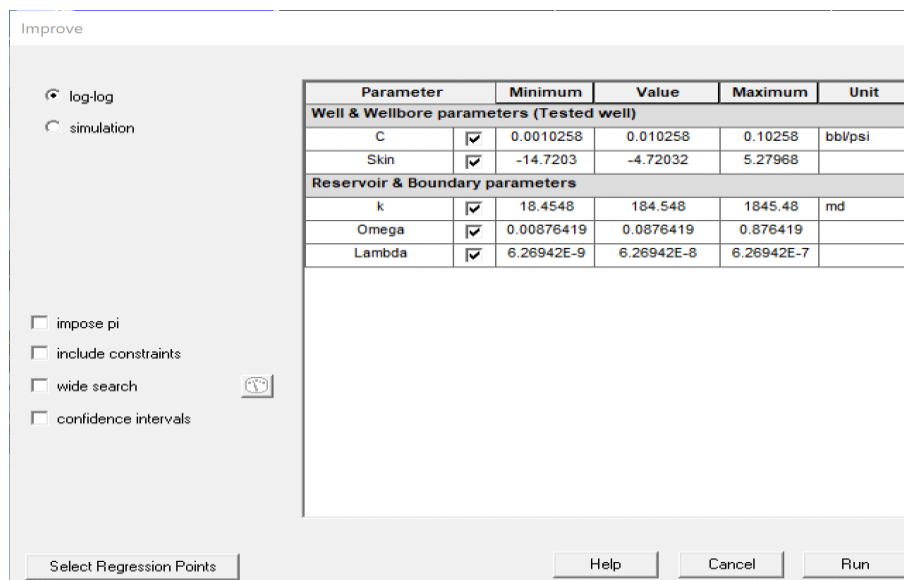


Figure8. Ecrin matching results using “improve option”

5. CONCLUSION

A spread sheet program was developed to analyze the buildup well test data in naturally fractured reservoir.

Buildup test data for an infinite conductivity fractured well (Case 1) was analyzed and the results showed that formation flow capacity = 1594.23 md.ft, fracture permeability = 19.44 md., storativity ratio (ω) = 0.000518 and internal flow coefficient (λ) = 7.80196×10^{-8} .

Buildup test data for an oil fractured well (Case 2) was analyzed and the results showed that formation flow capacity = 9195.848md.ft, fracture permeability = 255.44md., storativity ratio (ω) = 0.018 and internal flow coefficient (λ) = 6.86×10^{-6} .

Buildup test data for an oil fractured well (Case 3) was analyzed using Ecrinand the results showed that formation flow capacity = 6642md.ft, fracture permeability = 184.5md., storativity ratio (ω) = 0.087 and internal flow coefficient (λ) = 6.26×10^{-8} .

NOMENCLATURE

A: surface area of the matrix block, (ft²)

B: Oil formation volume factor, (rb/STB)

C_{DF+m} : Dimensionless wellbore storage

C_f : Capacity of the fracture, (ft³/psi)

C_{f+m} : Capacity of the whole reservoir

C_m : Capacity of the matrix, (ft³/psi)

c_o : Oil compressibility, (1/psi)

c_{pf} : Compressibility of the voids in fracture, (1/psi)

c_{pm} : Compressibility of the voids in matrix, (1/psi)

c_{tf} : fracture compressibility, (1/psi)

c_{tm} : Matrix compressibility, (1/psi)

c_w : Water compressibility, (1/psi)

k_f : permeability of the fracture, (md)

k_m : permeability of the matrix, (md)

m : slope

p_D : Dimensionless pressure

Q : flow rate, (bbl/D)

r_w : wellbore radius, (ft)

S_o : Oil saturation

S_w : Water saturation

t_D : Dimensionless time

V : volume of the matrix block, ft³

V_f : fracture volume, ft³

V_m : Matrix volume, ft³

X : characteristic length of the matrix block, (ft)

\emptyset_f : Porosity of the matrix

α : Geometric factor, (1/L²)

λ : interporosity flow coefficient

ω : storativity ratio

μ : viscosity, (cp)

ϕ_m : Matrix porosity

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