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**Evaluation of low permeability, naturally fractured carbonate reservoir with
Pressure Transient Analysis**

By

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**A report submitted in partial fulfilment of the requirements for
the MSc and/or the DIC.**

September 2012

DECLARATION OF OWN WORK

I declare that this thesis

“Evaluation of low permeability, naturally fractured carbonate reservoir with Pressure Transient Analysis”

is entirely my own work and that where any material could be construed as the work of others, it is fully cited and referenced, and/or with appropriate acknowledgement given.

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Evaluation of low permeability, naturally fractured carbonate reservoir with Pressure Transient Analysis

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Abstract

Well test analysis is an established procedure in well performance evaluation and reservoir appraisal. With new completion technologies and robust oil price, tight hydrocarbon formations are being increasingly evaluated for contingent development, as widely extensive tight formations or secondary reservoirs in existing fields, similar to the one in the present study. Such formations are usually tight carbonates and shales with poor effective porosity and the main flow path being the natural fractures. Well test analysis assists in evaluating the various properties of a double porosity reservoir.

Tight formations with poor effective porosity bear large uncertainty on pay thickness and subsequent reservoir volumetric data. The use of multi-layer double porosity interpretation model assists in reduction of the uncertainty on the pay thickness, which is initially indicated by wireline interpretation. This happens due to the fact that the fissure network is the main path of flow, and porosity to permeability correlations cannot be accurate if developed only by means of core analysis and extrapolated to wireline data.

The objectives are to assess reservoir properties through well test interpretation and assess methods to estimate connected fluid volume and present the optimal development option. Deconvolution of the subsequent flow periods has been used in order to access a further radius of investigation around the wellbore to observe radial flow stabilization. A method to estimate the connected drainage volume for each individual layer is proposed and compared to a method using deconvolved derivative time and pressure differential endpoint values (Whittle and Gringarten, 2008).

Fissure compaction was found to reflect on pressure transient response as a decrease of wellbore storage and increase of skin. Acid treatments and propped fracturing are the best known techniques for well productivity increase and skin reduction in tight reservoirs. While acid treatments increase rates, they have to be repeated due to fissure compaction around the wellbore with pore pressure decrease and have to be repeated in time, while propped fractures maintain the main flow path open through a wider reservoir contact area.

Introduction

Tight oil formations bear a range of uncertainties regarding effective formation thickness, fracture porosity and permeability. When a high contrast between fracture and matrix permeability is observed, the existence of a natural fracture network defines the main flow paths and reservoir pay zones, which is known as the double porosity model (Barenblatt et al., 1960). Early studies introduced the parameters that describe flow in a double porosity reservoir, such as the interporosity flow coefficient (λ) and storativity ratio (ω) that take into account reservoir anisotropy (Warren and Root, 1963).

With an increased amount of parameters acting as variables, the pressure transient data match with an interpretation model is often subject to multiple matching interpretations. Hence, an in depth study has to be performed in order to constrain the parameters range of validity and integrate data from other sources as inputs to support the interpretation model selection. A main target is to develop a consistent well test interpretation model that would take into account the phenomena that would alter the flow period behaviour throughout the test i.e. fissure compaction.

The fracture fluid flow can be approximated as a prismatic tube with smooth walls and calculated using the cubic flow law (Lomize 1951, Witherspoon et al. 1980), resulting that the permeability of a rock mass increases as a function of fracture density for homogenous fracture networks (Leckenby et al., 2005).

Double porosity behaviour exhibits a transient interporosity flow period occurring at middle times, while a fissured reservoir behaves similarly to a homogenous one at late times (Kazemi, 1969). The combination of a buildup test and a well interference test yield an approximate value of average matrix permeability. A quantitative estimation of fissure volume and porous blocks of the reservoir can be performed using type curves (Bourdet and Gringarten, 1980), yielding two characteristic

parameters: ω and λ , the ratio of fissure storativity to total storativity and the interporosity flow coefficient, respectively.

Fissured reservoirs and multi-layered reservoirs with high permeability contrast exhibit similar double porosity transient behaviour and may be distinguished only if their actual skin is zero (Gringarten, 1984). Wells in double porosity reservoirs yield lower skin values of around minus 3.5 due to a pseudo-steady state model of matrix block support and fracture face alternation (Stewart, 1988). In wells with double porosity behaviour, which are acidized, wellbore storage yields values up to two orders of magnitude higher than homogenous reservoirs, due to volume of connected fractures (Gringarten, 1984). The porous medium parameters (ω , λ) may vary with production time, due to the fracture geometry and volume variation, mainly due to pore pressure change.

The permeability tensor theory has been developed to integrate double porosity analytical solving models with Discrete Fracture Network (DFN) reservoir modelling (Oda, 1985). More geologically realistic reservoir models can be created, taking into account permeability anisotropy on all directions. Permeability tensor is important on deciding the direction of wells to be drilled. Seismic surveys and existent well test data will contribute in optimising well completion planning. DFN adds a tensor parameter to permeability calculations and an estimation of anisotropy deriving parameters for the double porosity continuum models (Dershowitz et al., 2000).

Pressure transient analysis using the logarithmic plot of pressure and Bourdet derivative has been empowered by the introduction of the deconvolution algorithm (Von Schroeter et al., 2001, Levitan 2007), which converts variable rate flow periods into a constant rate single drawdown flow period with duration equal to the sum of the test flow periods' durations. The algorithm provides access to a further radius of investigation using data for the whole test duration, rather than individual flow periods and the resultant data points can be matched with similar interpretation models using derivative numerical and type curve matching methods.

A recent pressure transient analysis interpretation method (Igbokoyi and Tiab, 2010), using elliptical flow has been developed in order to account for permeability anisotropy and provides a range of permeability and a direction of maximum horizontal permeability. Based on the elliptical flow interpretation model, a pressure transient test design has been developed, consisting of fracture injection test, shut-in, followed by fracture closure in the subsequent pressure falloff flow period (Martin et al., 2012). The interpretation of the fall-off periods yields the reservoir properties and an in-situ maximum and minimum horizontal formation stresses, providing valuable rock mechanics information about the reservoir.

Only fractures near wellbore increase productivity, while maximum productivity is obtained by wellbores directly intersecting fractures (Gureghian, 1975). The influence of a fracture on well performance depends on its orientation, length and distance to the producer wellbore, in case it is not directly connected (Givens et. al, 1966). Maximising reservoir contact is the main path to increased well productivity in tight formations. As such, horizontal wellbores, hydraulic fracturing and combination thereof are the most effective methods to achieve increased productivity. The interaction and interference of hydraulic fractures with pre-existing natural fractures in non-homogenous reservoirs is a key aspect in stimulation efficiency. Hydraulically fractured wells have optimum performance when the wellbore or the induced fractures intersect the existing natural fractures and are less or not affected by fractures not connected to wellbore (Meehan, 1989).

Another important aspect of hydraulic fracture propagation is the interaction of induced fractures with the existing fracture network. If a general direction of the natural fractures exists in the reservoir, the optimum stimulation results are achieved by a perpendicular intersection of the natural fractures by the induced ones. In highly anisotropic cases, the hydraulic fractures may be diverted into the existing network, causing proppant loss, smaller effective reservoir penetration, making pumping more difficult due to flow path tortuosity (Taleghani, 2009). Therefore it is assumed that hydraulic fracturing stimulation is more efficient in fissured reservoirs with isotropic in-situ horizontal stresses.

Methodology, Analysis and Discussion

Reservoir properties and Test Design

This study focuses in the use of well test analysis in the appraisal of a tight oil field, for which limited information and further studies are available. The reservoir studied is saturated with single phase light oil above bubble point, with low GOR. According to the petrophysical model, as seen in Fig. 2, there are two distinct producing layers, separated by a non-reservoir shale interval. The pay zones mostly consist of fissured limestone and wackestone carbonates. Due to the low pressure of this shallow reservoir, the fluid is produced with the use of a beam pump as represented in the completion drawing (Fig. 1).

Table 1: Reservoir and Fluid Properties

| | |
|-----------------------------------|----------------------|
| h_1 (ft) | 14 |
| h_2 (ft) | 9 |
| Well Deviation | 40° |
| ϕ_1 (av. Pay 1) | 0.135 |
| ϕ_2 (av. Pay 2) | 0.09 |
| c_t (psi ⁻¹) | 3.8×10^{-6} |
| B_o (rb/stb) | 1.03 |
| GOR (scf/stb) | 108 |
| API (°) | 36 |
| SG (g/cc) | 0.856 |
| S_{or} (min) | 0.19 |
| S_{wc} (min) | 0.17 |
| μ_o (cp) | 3.8 |
| r_w (ft) | 0.583 |
| p_i (psia) | 1188.5 |
| p_i datum (psia) 742 m TVDss | 1061.5 |
| p_b (psia) @ 100° F | 301.7 |
| T (°F) | 95 |

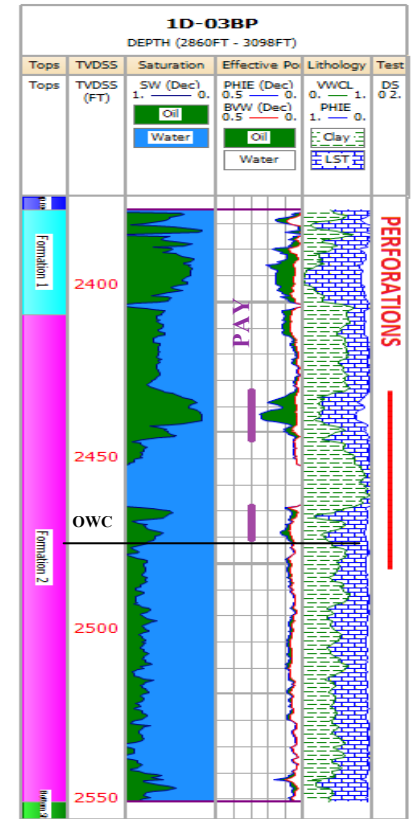
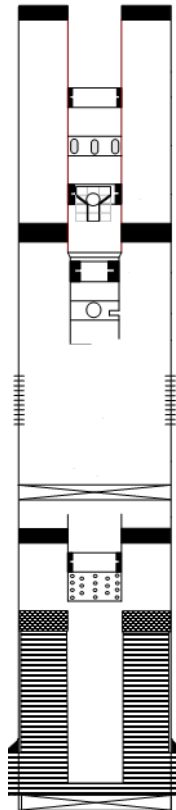
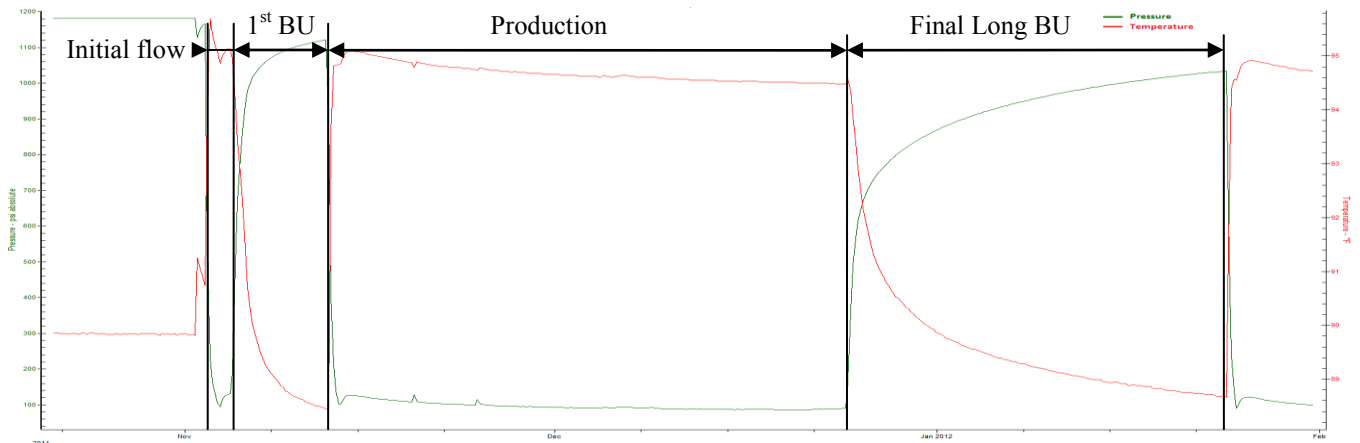
**Fig. 1: Completion Drawing and petrophysical model of the tested well**

Figure 3 illustrates the test design, which is typical for low permeability formations. An initial short flow is followed by a short shut in to validate initial reservoir pressure measurements and estimates depending on depth. A longer duration production to provide a better measurement of time averaged rates is followed by a last long duration buildup.

**Fig. 2: Well Test Design**

Identification of double porosity behaviour

Prior to typical type curve matching of middle time behaviour and pressure derivative analysis, there are several indications to suggest double porosity as the most appropriate interpretation model. A wellbore storage much higher than the one expected for the tested well geometry and depth for a homogenous reservoir, is a good indication of a secondary porosity volume connected to the wellbore and contributing to prolonged duration of the early times phenomenon. It is important to note that the well is not damaged, nor acidized. The majority of fluid production is driven by fluid expansion and contraction of the fracture volume in the fissure medium. The pressure change and Bourdet derivative indicate a unit slope trend, corresponding to wellbore storage and skin, as no fracture with high permeability contrast to the fissure network is directly

connected to the wellbore.

Additionally, core tests indicating consistently significantly lower permeability values than the permeability figures resulting from pressure transient analysis. Permeability in tests is obtained through radial flow stabilization identification and subsequent mobility values for the producing pay zones. This observation is a good indication that small scale core plugs behave differently than the formation porous medium at the reservoir scale. Table 2 illustrates the difference in permeability derived from well test interpretation compared to the one interpreted through porosity to permeability correlation (Fig. 3) in conjunction with wireline interpretation averages.

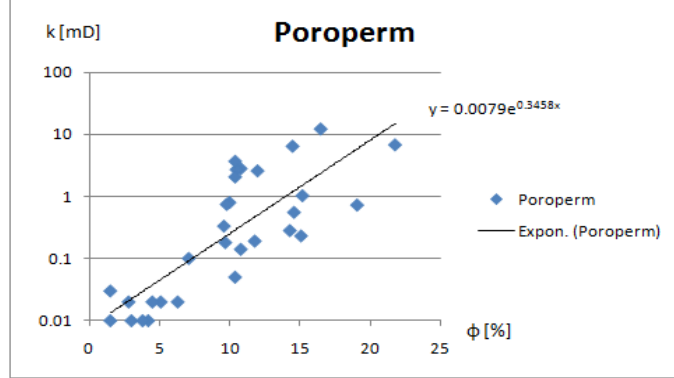


Fig. 3: Porosity to permeability correlation from core laboratory tests

Table 2: Well test permeability versus core RCA test

| | Well Test k_{IARF} [mD] | Core k_C [mD] | k_{IARF}/k_C ratio |
|---------|------------------------------|--------------------|----------------------|
| Layer 1 | 19.3 | 0.84 | 23.0 |
| Layer 2 | 6 | 0.18 | 33.3 |

A common indication used to identify double porosity behaviour is the transition between two distinct radial flow stabilizations at the same level and the “S” shape curvature of the pressure log-log plot. However that is rare, due to superposition with other transient phenomena, or it occurs during wellbore storage unit slope region. The first radial flow, often not identified as a straight line, may superpose with other early times phenomena. In the case that both radial flow regimes manifest in time without other superposed phenomena, the double porosity behaviour can be identified by two parallel lines with the same slope on the Horner plot, one during middle and the other during late times.

However, identification through the transition between two radial flow stabilizations does not suffice to satisfy the interpretation model uniqueness criterion, as in many cases double porosity behaviour can be confused with a sealing fault boundary on a homogenous reservoir and vice versa. Hence, it is essential to be aware of the expected distances to flow barriers that can be identified within seismic resolution, to be used as confining parameters.

Storativity Ratio and Interporosity flow determination

The two main characteristics of double porosity behaving reservoirs are defined from literature as follows in Eq. (1) and (4)

$$\omega = \frac{(\phi V_{c_t})_f}{(\phi V_{c_t})_{f+m}} \dots \dots \dots (1)$$

As the total compressibility is assumed the same for fracture and matrix and the fracture porosity is equal to unity:

$$\omega = \frac{V_f}{V_f + \phi_m} \dots \dots \dots (2)$$

$$V_f = \frac{\omega}{1-\omega} \phi_m \dots \dots \dots (3)$$

$$\lambda = \alpha r_w^2 \frac{k_m}{k_f} \dots \dots \dots (4)$$

$$a = \frac{4n(n+2)}{l^2} \dots \dots \dots (5)$$

For a layered fracture pattern, as the one identified in this study, Eq. (4) turns to:

$$\lambda = \frac{12}{h_m^2} r_w^2 \frac{k_m}{k_f} \dots \dots \dots (6)$$

Having some estimates for the distance between the fractures from core samples and some core plugs RCA measurements yielding matrix permeability (k_m), Eq. (6) would yield an estimate of the fracture permeability. That would allow for a porosity to permeability correlation equation to be developed using total porosity (ϕ_{f+m}), based on the assumption of a

homogenous distribution of planar fractures spatially within the reservoir. The interporosity flow parameter (λ) represents the ability of the matrix to flow into the fissure network.

Fluid mobility is calculated using the Bourdet derivative for the infinite acting radial flow after the interporosity flow transition Eq. (7).

$$\frac{kh}{\mu} = \frac{70.62QB_o}{\Delta p} \quad (7)$$

Deconvolution of multiple flow periods

In view of recent advance in well test analysis the application of the deconvolution algorithm to convert two main buildup flow periods into a single constant rate drawdown can be used in order to obtain access to further radius of investigation. This assisted in determining the infinite acting radial flow line yielding reservoir mobility on the Bourdet derivative, as presented in Fig. 4(b).

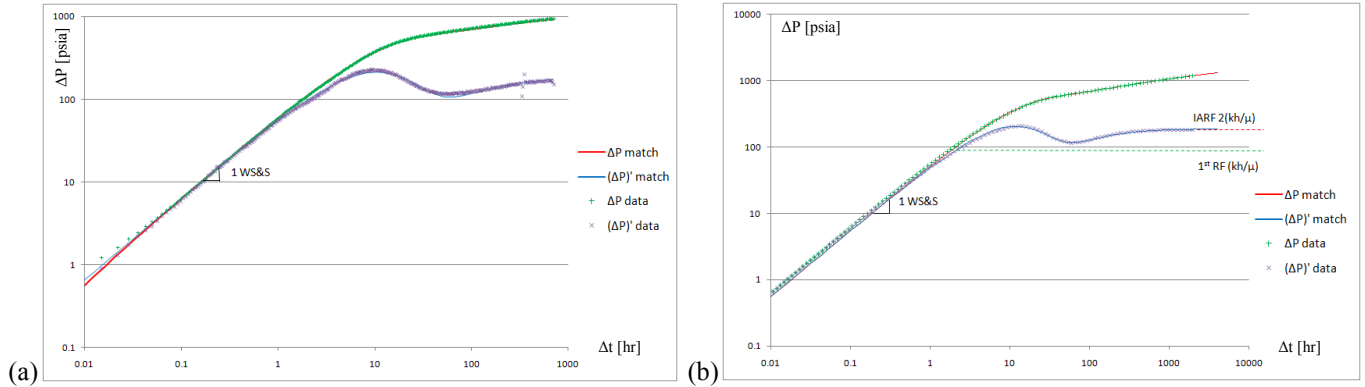


Fig. 4: Δp and $\Delta p'$ Log-Log plot for longest buildup (a), deconvolved drawdown curve (b) and interpretation match models

Deconvolution algorithm yields an average reservoir pressure which shall validate previously available RFT measurements and estimations from gauge readings prior to production. One of the main sources of uncertainty is the calculation of rates due to lack of direct measurement and time-averaged nature. Splitting longer production periods in variable rate flow periods allows for rate adjustment according to the corresponding pressure transient response through deconvolution algorithm.

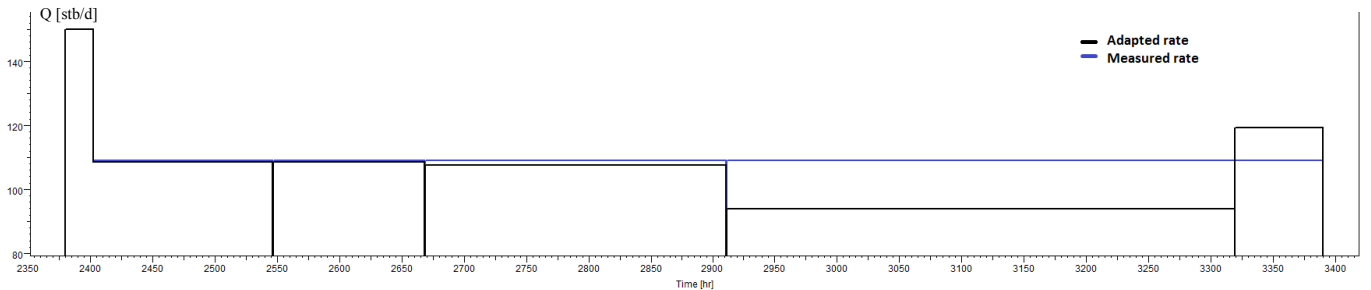
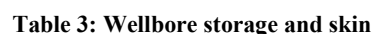


Fig. 5: Adapted rates by deconvolution for the main production flow period

Test results

A double layer model was selected based on the petrophysical interpretation (Fig. 2) of an impermeable layer separating the pay zones. A fault with high throw, which is considered to be a sealing boundary is identified from the seismic sections and top structure map. It is expected to exhibit a sealing boundary pressure transient behaviour at time, corresponding to a certain distance from the well. The fact that pay layers' thickness are defined, constrains the options for selecting the pseudo-radial flow mobility stabilization that corresponds to the 0 slope straight line in the log-log Bourdet derivative plot (Fig 4b) after the boundary transient behaviour has fully developed. The stabilization line, would yield half of the reservoir mobility that would correspond to an equivalent infinite acting radial flow.

The lower value of wellbore storage and slight increase in skin at the second buildup indicate fracture compaction near the wellbore due to low downhole flowing pressure during production time. The effect is small within the duration of the test, but is expected to increase with longer production time. It may indicate that the fracture network permeability decreases with the in situ stress condition affected by the pore pressure drop (Qingfend et al., 2010). It is observed as a near wellbore skin increase and a decrease of wellbore storage in the second buildup that followed the longer production, as the fracture volume contributing to wellbore storage decreased, as seen in Fig. 6.



| | WS [bbl/psi] | S | Δt [h] |
|----------------------|--------------|-------|----------------|
| BU 1 | 0.084 | -3.4 | 185 |
| BU 2 | 0.072 | -3.24 | 723 |
| Deconvolved Drawdown | 0.085 | -3.4 | 2008 |

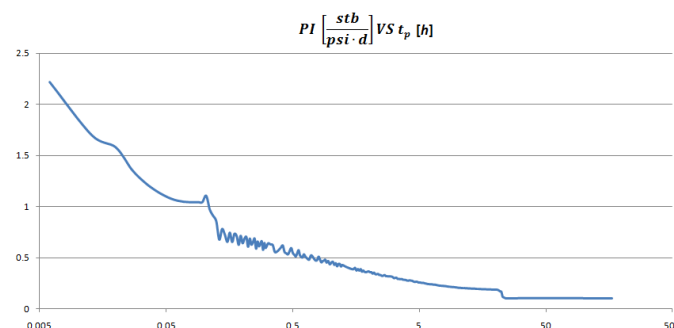


Fig. 7: Productivity index versus production time (t_n)

No cross-flow is assumed between the layers, as there is an apparent flow barrier with a thickness of around 15 ft, as seen on the wireline interpretation model (Fig. 2). Furthermore, there is no radial diffusion within the matrix, which is assumed to only flow into the fissures. The well productivity index is calculated as follows:

$$PI = \frac{Q}{p_i - p_{wf}} \dots\dots\dots (8)$$

Table 4: Test interpretation results from deconvolved derivative drawdown analysis

| Layer | p _i [psia] | C [bbl/psi] | S | h [ft TVD] | φ [%] | kh [mD•ft] | k [mD] | λ | ω | L [ft] |
|-------|-----------------------|-------------|------|------------|-------|------------|--------|--------------------|------|--------|
| 1 | - | - | -3.4 | 14 | 13.5 | 270.2 | 19.3 | 3·10 ⁻⁶ | 0.15 | 470 |
| 2 | - | - | -3.4 | 9 | 9 | 53.8 | 6 | 3·10 ⁻⁶ | 0.15 | 479 |
| Total | 1188.51 | 0.085 | - | 23 | 12 | 324 | 14.1 | - | 0.15 | - |

Table 5: Analysis consistency between the longest BU and deconvolved DD derivative analysis. Well location map.

| Verification of Analysis Consistency | | | | | Top structure map | |
|--------------------------------------|----------|----------------|------------|---|-------------------|--|
| Parameter | Log-Log | Deconvolved DD | Difference | | | |
| p _{av} [psia] | 1188.5 | 1188.5 | 0 | % | | |
| kh [mD·ft] | 323 | 324 | 0.68 | % | | |
| C [Bbl / psi] | 0.0719 | 0.085 | 15.4 | % | | |
| S | -3.24 | -3.4 | 0.16 | ± | | |
| ω | 0.15 | 0.15 | 0 | % | | |
| λ | 3.06E-06 | 3.06E-06 | 0 | % | | |
| L [ft] | - | 470 | - | - | | |

The interpreted porous medium of the reservoir is presented in Fig. 8 and found to be corresponding to the core inspection observations. Planar, parallel fractures on a single general direction are observed.

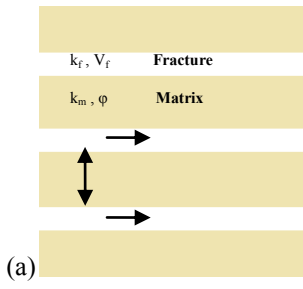


Fig. 8: Double porosity model

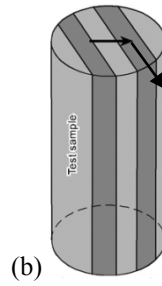


Fig. 9: Core sample

The relatively high values of storativity ratio indicate a layered type fracture network with $k_f \gg k_m$. Similar storativity ratio (ω) values are obtained by tests on another well in the same formation. The fracture planes are parallel and on a single direction as seen in Fig. 9. Inspection of the core samples qualitatively validates the assumption, with open fractures existing on a single direction, being parallel to each other (Fig. 9, 10). The partially open and open fractures show one North to South main trend after calibrating the core according to the well deviation azimuth (Fig. 10). Their orientation relative to the wellbore has a major impact on stimulation design and effectiveness, as propped fractures intersecting natural fissures can be diverted. Multiple layers further contribute in the high values of storativity ratio (Gringarten, 1984).

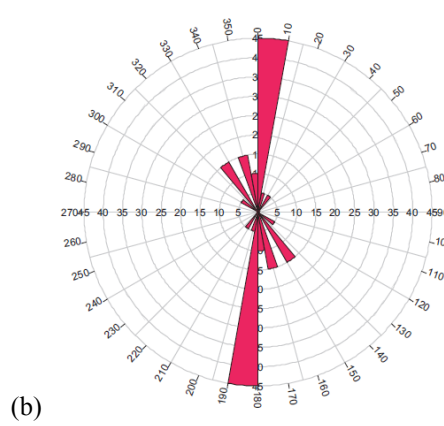
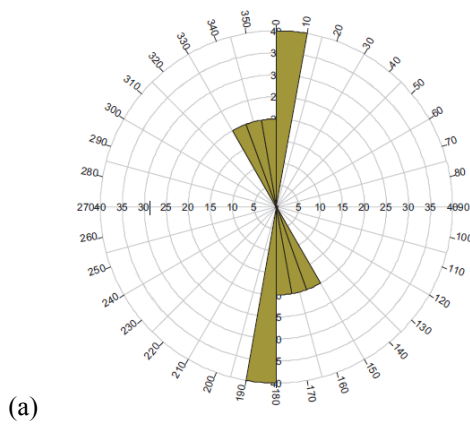


Fig. 10: Calibrated fracture orientation based on fracture mapping study ($N = 0^\circ$) for open (a) and partially open (b) fractures

The test reached pseudo-radial flow after encountering a no flow boundary (sealing fault). Hence for the resultant partially radial drainage, the horizontal drainage area section is presented in Fig. 11.

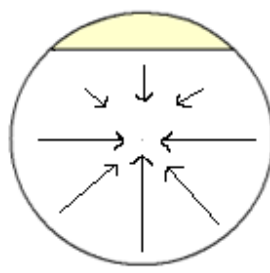
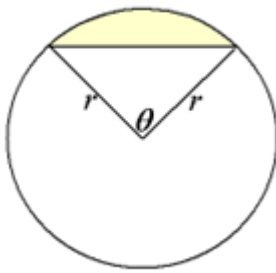


Fig. 11: Drainage area section

The centre of the circle corresponds to the well location and the marked segment (Fig. 11) corresponds to an area that is not accessible due to the sealing fault. The area of the drainage area excluding the segment is calculated as follows:

$$A = \pi r^2 - \frac{r}{2}(\theta - \sin \theta) \dots\dots\dots (9)$$

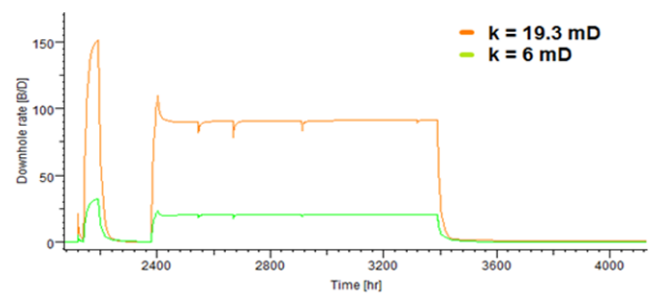


Fig. 12: Rate per reservoir layer

Where:

$$\begin{aligned} r &= r_i, \text{ the test radius of investigation (3747 ft for layer 1, 2445 ft for layer 2)} \\ \theta &= \text{the angle illustrated in Fig. 11 (in radians)} \end{aligned}$$

The different values of radius of investigation are based on a theoretical model, taking into consideration the permeability of each layer in calculating the radius of investigation

The angle θ (Fig 11) can be obtained using the following equation:

$$\begin{aligned} \theta &= 2\arccos\left(\frac{L}{r}\right) \dots\dots\dots (10) \\ \theta_1 &= 2.89 \text{ (rad)} \\ \theta_2 &= 2.74 \text{ (rad)} \end{aligned}$$

Where:

$$L = \text{distance to the fault.}$$

For: $r_{i1} = 3747 \text{ ft}$ and $r_{i2} = 2445 \text{ ft}$

We obtain:

$$\begin{aligned} A_1 &= 4.096 \text{ km}^2 \\ A_2 &= 1.744 \text{ km}^2 \end{aligned}$$

The corresponding gross rock volume is given by:

$$\begin{aligned} GRV &= A \cdot h \dots\dots\dots (11) \\ GRV_1 &= 1.748 \cdot 10^7 \text{ m}^3 \\ GRV_2 &= 4.783 \cdot 10^6 \text{ m}^3 \end{aligned}$$

The pore volume for each layer is given by:

$$\begin{aligned} PV &= GRV \cdot \phi \dots\dots\dots (12) \\ PV_1 &= 14.8 \cdot 10^6 \text{ rb} \\ PV_2 &= 2.7 \cdot 10^6 \text{ rb} \end{aligned}$$

Assuming the average oil saturation for the pay zones from wireline log petrophysical interpretation of $S_o \sim 0.6$ we obtain the respective STOIP values.

$$\begin{aligned} STOIP &= \frac{PV \cdot S_o}{B_o} \dots\dots\dots (13) \\ STOIP_{min,1} &= 8.64 \text{ MMstb} \\ STOIP_{min,2} &= 1.58 \text{ MMstb} \end{aligned}$$

The total fluid volume connected to the wellbore, as identified through the pressure transient test is 10.2 MMstb. Despite the considerable amount of oil connected to the wellbore, the recovery factor is expected low, due to lack of reservoir pressure support and low permeability of the porous medium.

Another method is available in the literature (Whittle and Gringarten, 2008) is presented in Eq. 14.

$$STOIP_{min \text{ tested}} = \frac{S_o}{24c_t} Q \frac{\Delta t_{max}}{\Delta P'_{max}} \dots\dots\dots (14)$$

Where Δt_{max} and $\Delta P'_{max}$ correspond to the coordinates of the last point of the constant rate drawdown pressure derivative.

Using the aforementioned calculation for estimating the STOIP from deconvolved drawdown derivative, a value of 8.55 MMstb is obtained, presenting a 16% difference from the previously calculated value. Bearing in mind the fact that various

parameters as well as $\Delta'P_{\max}$ are subject to uncertainty at the appraisal phase, the results of both methods are deemed fairly close.

Hydraulic fracturing a naturally fissured reservoir

In the case of hydraulic fracturing stimulation, the pumped fluid will be diverted into the natural fracture network, reopening existing cemented fractures or being lost in the network. To obtain best stimulation results by propped fracturing, the induced fractures should intersect perpendicularly to pre-existing fissures. Otherwise, flow path diversion induced tortuosity makes the pumping job difficult (Taleghani, 2009), fluid is lost and the drainage area accessed by the induced fracture smaller, as illustrated in Fig. 11. Fractures propagate along the maximum horizontal stress direction. Thus, knowledge of the regional subsurface stresses is essential for designing stimulation by fracturing. From the collected induced fractures on the core samples it can be deduced that the actual horizontal maximum stress in the well site could correspond to a NW-SE tectonic compression that affects the reservoir area, being the most likely path of potential propped fractures propagation.

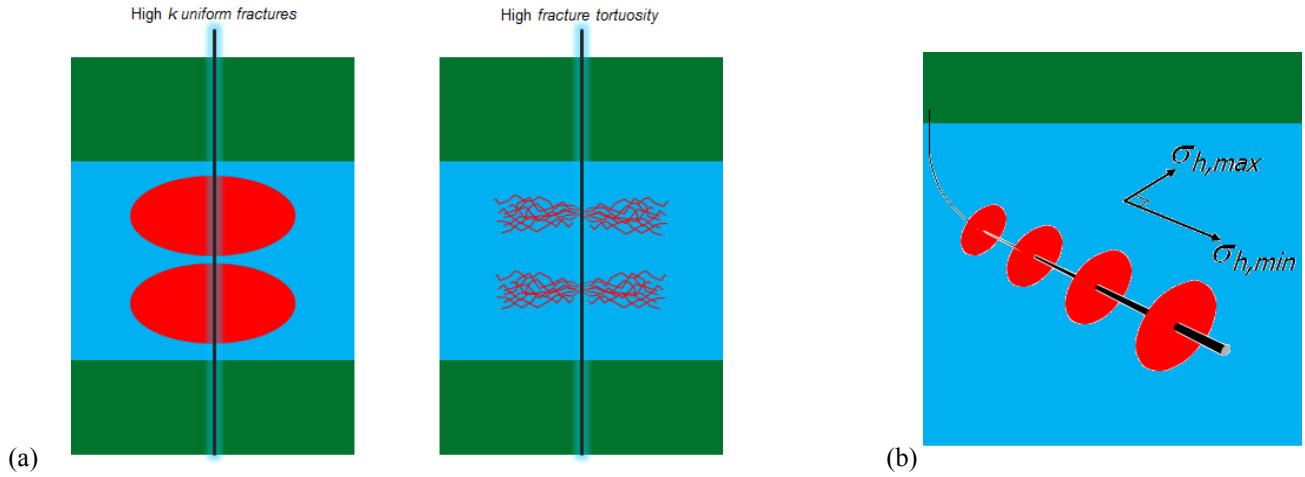


Fig. 13: Uniform fracture and high tortuosity fractures propagation on the vertical (a) and horizontal plane (b)

At early times, linear flow replaces wellbore storage, while the reservoir inflow area would be increased by a few orders of magnitude. Turbulence induced rate dependent skin (Dq) may be a concern only in gas reservoirs due to the non-conformal contact of the fracture to the wellbore.

An equation for propped fracture conductivity is presented:

$$C_f = w_{av}k_p \quad (15)$$

The fracture conductivity may vary during production time due to clay depositions, changes in reservoir pressure and formation stresses. A dimensionless variable for fracture conductivity is used to indicate how conductive a fracture is, compared to the ability of the formation to deliver fluid to the fracture.

$$C_{fD} = \frac{C_f}{x_f k} = \frac{w_{av}k_p}{x_f k} \quad (16)$$

A unified fracture design has been developed, based on the dimensionless proppant number (Economides et al., 2001) for radial and square drainage, respectively:

$$N_p = \frac{2k_f w_{av}}{r_e k \sqrt{\pi}} \quad (17)$$

$$N_p = \frac{2k_f w_{av}}{ak} \quad (18)$$

Various optimal dimensionless fracture conductivity ($C_{fD,opt}$) values have been empirically determined (Economides et al. 2001), resulting after an iterative process values for x_f , k_p , x_e , and w_{av} that respect Eq. 16.

$$\frac{w_{av,opt}}{x_{f,opt}} = C_{fD,opt} \frac{k}{k_f} \quad (19)$$

Conclusions

In view of the advance in drilling and completion technology (horizontal wells, coiled tubing, open-hole fracture designs) tight fissured formations with poor conventional productivity can be brought to light and provide economical rates. Appraisal is more complex, while characterization is crucial for planning the development options and subsequent completion designs. Pressure transient analysis is a key element, providing plenty of information on reservoir quantitative and qualitative properties. Decisions based on improved information are expected to result in improved field development and value.

1. It was verified that heterogeneous reservoirs with double porosity behaviour imply that the permeability measured in a test and the permeability measured in a core correspond to different porous media, as the reservoir medium cannot be scaled down to a plug and maintain the same flow properties.
2. Economic flow rates from the tight carbonates are dependent on the development of an open natural fracture system. Predicting the spatial extent of such a system with data from a single existing wellbore will be unreliable and require long duration pressure history, for the subsequent flow periods to develop due to relatively low fluid mobility.
3. It is expected that the permeability of the fracture network will decrease due to fissure compaction with reservoir pressure decrease. However, within the test duration it is observed in the form of a near wellbore effect, with increase of the skin and decrease of the wellbore storage for the last buildup. After significant production time, it is expected that the mobility corresponding to radial flow stabilization will decrease, as a result of decreased reservoir permeability.
4. The use of downhole shut-in tools reduces the wellbore storage duration of DSTs in fissured reservoirs providing more information and less duration for the well tests, however this is not applicable in this case, as the fissure volume is mainly contributing to the wellbore storage phenomenon.
5. Well test interpretation of double porosity reservoir in appraisal yields quantitative and qualitative information on double porosity reservoirs. However, the values obtained for the various variables are averages, and several heterogeneities in the fissure network that could affect long term production are not captured.
6. The high value of storativity ratio (ω) yielded from this test can be interpreted by the multiple layers and the single direction of the planar parallel natural fractures.
7. While acid treatment can prove effective as short term stimulation, only propped fracturing can provide a longer production at economic rates, as the propped fracture would be less subject to compaction. The change into linear flow at early times, the increased contact area to the reservoir result in increased drainage area for a given production time.
8. Fracture injection tests are proposed to be performed on formations similar to the one studied in order to obtain permeability tensor and in-situ rock mechanics information from the fracture closure pressure fall-off analysis.

Recommendations for Further Study

Deconvolution of several flow periods on mature fissured fields with permanent gauges in the wells and complete rate history can show how the fracture network compaction with pressure decrease affects the effective reservoir permeability. Similarly, tests on wells with propped fractures and similar design can give a comparison on how near wellbore effects are affected by production at low well flowing pressure (p_{wf}).

Reservoir sector and full field simulation models with double porosity behaviour modelled similarly to the well test interpretation results that yield predictions similar to the interpretation results would improve confidence on qualitative interpretation and can prove to be the basis for a realistic discrete fracture network reservoir model.

Fracture injection tests pressure falloff analysis, in conjunction with the use of elliptical flow model may bring a breakthrough in fissured reservoirs appraisal. The orientation of maximum permeability and its spatial variation, as well as some in situ rock stress information can be obtained, as essential information on deciding upon induced fracturing stimulation. Given an appropriate duration, a fracture injection test could provide water mobility information, essential for water injection planning. The development of new type curves corresponding to several post-injection falloff flow periods would be a direction of further study.

Acknowledgements

I would like to show my gratitude to PERENCO for provision of the topic and collaboration throughout this study.

Nomenclature

| | | | |
|----------|---|------------------|---|
| a | Side length of square drainage area (a^2) | ΔP_{max} | Last value of deconvolved pressure derivative |
| A | Area (of drainage) | DD | Pressure Drawdown (production) |
| B_o | Oil formation volume factor | DST | Drill Stem Test |
| BU | Pressure Buildup | $Eq.$ | Equation |
| c_t | Total compressibility (psi^{-1}) | θ | Angle (rad) |
| cp | Centipoise | $^{\circ}F$ | Degrees Fahrenheit |
| C | Wellbore Storage, also WS (bbl/psi) | $Fig.$ | Figure |
| Δ | Change in a given parameter | ft | Feet |
| | | GOR | Gas to Oil ratio (scf/stb) |

| | | | |
|------------|--|----------|---------------------------------------|
| GRV | Gross Rock Volume | rb | Barrel volume at reservoir conditions |
| h | Reservoir thickness (ft) | r_e | Drainage radius |
| k | Permeability (mD) | r_i | Radius of investigation (ft) |
| k_p | Proppant permeability | r_w | Well radius (ft) |
| λ | Interporosity flow coefficient | S | Skin |
| L | Distance to flow boundary | SG | Specific Gravity of fluid (g/cc) |
| M | Mobility | S_w | Water saturation |
| mD | 10^{-3} Darcy | S_{wc} | Connate water saturation |
| μ | Fluid viscosity | S_o | Oil saturation |
| p | Pressure (psi) | S_{or} | Residual oil saturation |
| ϕ | Porosity | stb | Stock tank barrels |
| ϕ_m | Matrix porosity | $STOIIP$ | Stock tank oil initially in place |
| ΔP | Change in pressure (psi) | T | Temperature ($^{\circ}F$) |
| $\Delta'P$ | Bourdet pressure derivative (psi) | ω | Storativity ratio |
| p_i | Average Initial reservoir pressure (psi) | t | Time |
| p_{wf} | Pressure (well flowing) | t_p | Production time |
| p_b | Bubble point pressure (psia) | x_f | Fracture half length |
| PI | Productivity Index (stb/psi•d) | V_f | Fracture volume |
| PV | Pore volume | w_{av} | Average fracture width |
| Q | Flow rate (stb/day) | w | Fracture width |
| RCA | Routine Core Analysis | | |

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Appendix A: Literature Review

Table A-1: Important Milestones

| | Paper number | Year | Title | Authors | Contribution to Science |
|----|--|------|--|--|---|
| 1 | J. Applied Mathematics 24 (5) 1286-1303 | 1960 | Basic concepts in the theory of seepage of homogenous liquids in fissured rocks | Barenblatt G.I., Zheltov I.P., Kochina I.N | Basic dual porosity theory. Matrix blocks feed fractures to flow into the wells |
| 2 | SPE-426-PA | 1963 | The behaviour of Naturally fractured Reservoirs | Warren J.E., Root P.J. | Interporosity flow coefficient, storativity ratio, “sugar cube” model with reservoir anisotropy taken into account. |
| 3 | SPE-1356-PA | 1966 | Effect of isolated vertical fractures existing in the reservoir on fluid displacement response | Givens J.W., Crawford P.B. | Key parameters controlling well performance on isolated naturally fractured models: Orientation, connected fractures length and distance to the producing well using potentiometric model |
| 4 | SPE-2156-A | 1969 | Pressure transient Analysis of Naturally Fractured Reservoir with uniform fracture distribution | Kazemi H. | First transient interporosity flow model. Obtained the total flow capacity and storativity ratio. |
| 5 | SPE-1718-PA | 1975 | A study of the Finite-Element Method of the Influence of Fractures in Confined Aquifers | Gureghian A.B. | Finite element model of isolated fractures in aquifers. Only fractures near wellbore increase productivity |
| 6 | SPE-9293 | 1980 | Determination of Fissure Volume and Block Size in Fractured Reservoirs by Type-Curve Analysis | Bourdet D., Gringarten A.C. | First type curve for well test on double porosity reservoirs with wellbore storage and skin. Quantitative estimation of fissure volume and porous blocks of the reservoir |
| 7 | JPT Apr. 1984 549-564 | 1984 | Interpretation of Tests in Fissured and Multilayered Reservoirs with Double-Porosity Behavior: Theory and practice | Gringarten A.C. | Summary of mathematical models for dual porosity systems and insight of the inverse well test problem: identification of behaviour |
| 8 | Geotechnique 35, 483 (1985) | 1985 | Permeability Tensor for Discontinuous Rock Masses | Oda M. | Permeability tensor theory for directional fracture system permeability modelling. Important on deciding the direction of wells to be drilled |
| 9 | SPE-18173-MS | 1988 | Well test interpretation for Naturally fractured reservoirs | Stewart G., Asharsobbi F. | Concluded on negative pseudoskin of wellbores connected to fracture network using a new developed dimensionless derivative type curve |
| 10 | PhD thesis, Stanford University | 1989 | Hydraulically fractured wells in heterogeneous reservoirs: Interaction, Interference and optimisation | Meehan D.N. | Hydraulically fractured well and parallel natural fracture have minor productivity effect |

| | | | | | |
|----|--|------|--|--|--|
| 11 | SPE-62498 | 2000 | Integration of Discrete Fracture Network methods with Conventional Simulator approaches | Dershowitz B., LaPointe P., Eiben T. | Integration of dual porosity model and Discrete Fracture Network modelling, making the reservoir modelling more geologically realistic |
| 12 | Elsevier publishing ISBN 978-0-88415-317-7 | 2001 | Geologic Analysis of Naturally Fractured Reservoirs | Nelson R.A. | Categorisation of naturally fractured reservoirs and their geological and flow properties |
| 13 | Journal of Volcanology and Geothermal research 148 (200) 116-129 | 2005 | Estimating flow heterogeneity in natural fracture systems | Leckenby R.J., Sanderson D.J., Lonergan L. | Review of fracture flow properties, study on fault type effects on natural fractures orientation, network and flow patterns. Case study from western England basin |
| 14 | SPE-138404 | 2010 | New Method of Well Test Analysis in Naturally Fractured Reservoirs Based on Elliptical Flow | Igbokoyi A.O., Tiab D. | Use of Elliptical flow interpretation model for quantifying the permeability anisotropy in naturally fractured reservoirs. Direction of fluid flow prediction |
| 15 | SPE-152019 | 2012 | A Method to perform Multiple Diagnostic Fracture Injection Tests Simultaneously in a single Wellbore | Martin A.R., Cramer D.D., Nunez O., Roberts N.R. | Injection fracturing shut in tests for deriving reservoir properties and minimum horizontal stress direction (for natural fracture investigation) |

1.

Journal Applied Mathematics
24 (5) 1286-1303

1960

Basic concepts in the theory of seepage of homogenous liquids in fissured rocks

Authors: Barenblatt G.I., Zheltov I.P., Kochina I.N

Contribution to the understanding of flow in naturally fractured reservoirs:

Basic dual porosity theory. Matrix blocks feed fractures to flow into the wells

Objective of the paper:

Bring an insight in the fractured and multi-layered reservoirs

Methodology used:

Developed own analytical model for double porosity

Main Conclusions:

Matrix blocks feed fractures to flow into the wells

Comments:

First dual porosity theoretical model. It is neglecting flow from matrix directly to the wellbores

2.

SPE-426-PA

1963

The behaviour of Naturally fractured Reservoirs

Authors: Warren J.E., Root P.J.

Contribution to the understanding of flow in naturally fractured reservoirs:

Establishing concepts such as the interporosity flow coefficient and storativity ratio

Objective of the paper:

Bring an insight in the fractured and multi-layered reservoirs

Methodology used:

“Sugar cube” model presented by this paper with reservoir anisotropy taken into account.

Main Conclusions:

A new analytical model for flow in fractured reservoirs

Comments:

The first model to take into account reservoir anisotropy

3.

SPE-1356-PA

1966

Effect of isolated vertical fractures existing in the reservoir on fluid displacement response

Authors: Givens J.W., Crawford P.B.

Contribution to the understanding of flow in naturally fractured reservoirs:

Establishing parameters controlling well performance on isolated natural fractured models.

Objective of the paper:

Study parameters influencing well performance in naturally fractured reservoirs and particularly the effect of vertical fractures existing in the reservoir matrix which are not necessarily connected to the wellbores.

Methodology used:

Potentiometric model

Main Conclusions:

Orientation, connected fractures length and distance to the producing well are the parameters driving well performance in fissured reservoirs.

Comments:

Assumptions: steady state conditions, mobility ratio equal to unity and neglecting capillary and gravitational phenomena effects.

4.

SPE-2156-A

1969

Pressure transient Analysis of Naturally Fractured Reservoir with uniform fracture distribution

Authors: Kazemi H.

Contribution to the understanding of flow in naturally fractured reservoirs:

Establishing the first transient interporosity flow model

Objective of the paper:

Study interporosity flow and fractured reservoir properties in situ. Attempt to develop a mathematical model and review all existing analytical models to date.

Methodology used:

Developed the transient interporosity flow model

Main Conclusions:

Verification of conclusions by Warren and Root theory

From a buildup test, the total flow capacity and storativity ratio are obtainable.

Combination of a buildup test and a well interference test will yield an approximate value of average matrix permeability

Comments:

A fractured reservoir is observed to behave similarly to a homogenous one at late times.

5.

SPE-1718-PA

1975

A study of the Finite-Element Method of the Influence of Fractures in Confined Aquifers

Authors: Gureghian A.B.

Contribution to the understanding of flow in naturally fractured reservoirs:

To bring an understanding that the position of the wells relative to the fracture network largely affect the resultant productivity

Objective of the paper:

Study the effect of fracture orientation and distance from wells effect on productivity

Methodology used:

Finite element model of isolated fractures in aquifers.

Main Conclusions:

Only fractures near wellbore increase productivity

Comments:

Maximum productivity is obtained by wells intersecting the fracture(s).

6.

SPE-9293

1980

Determination of Fissure Volume and Block Size in Fractured Reservoirs by Type-Curve Analysis

Authors: Bourdet D., Gringarten A.C.

Contribution to the understanding of flow in naturally fractured reservoirs:

A new type curve for well test on double porosity reservoirs with wellbore storage and skin.

Objective of the paper:

Quantitative estimation of fissure volume and porous blocks of the reservoir

Methodology used:

Developed new type-curve

Main Conclusions:

Well test data for double porosity systems can be analytically studied, yielding two characteristic parameters: ω and λ , the ratio of fissure storativity to total storativity ($f+m$) and the interporosity flow coefficient, respectively.

The radius of double porosity effect is limited and depends on λ , (interporosity flow coefficient) and at later times homogenous behaviour can be observed, confirming Kazemi H. observations on SPE-2156-A.

Comments:

Contributed into understanding the log-log derivative analysis of well test data using the double porosity model for fractured reservoirs.

7.

JPT Apr. 1984
549-564

1984

Interpretation of Tests in Fissured and Multilayered Reservoirs with Double-Porosity Behavior: Theory and practice

Authors: Gringarten A.C.

Contribution to the understanding of flow in naturally fractured reservoirs:

Not much, summarizing knowledge to date, mainly from SPE-9293 (Bourdet et. al). Providing further insight on the inverse problem of identifying a double porosity behaviour from a pressure transient data set.

Objective of the paper:

Summary of mathematical models for dual porosity systems and insight of the inverse well test problem: identification of behaviour.

Methodology used:

Bourdet D., Gringarten A.C. type curves from SPE-9293

Main Conclusions:

1. Fissured reservoirs and multi-layered reservoirs with high permeability contrast exhibit similar double porosity behaviour
2. Double porosity is better diagnosed by log-log analysis of the pressure derivative (over time).
3. Wells in double porosity reservoirs yield lower skin values, due to a pseudoskin of around minus 3.5.
4. Fissured reservoirs can be distinguished from multilayer reservoirs only if actual skin is 0 (non-damaged nor acidized).
5. Downhole shut in equipment is ineffective, as wellbore storage of fissured reservoir is 1-2 orders of magnitude higher than the case of multi-layered or homogenous reservoirs due to volume of connected fractures.
6. ω , λ may change with time, due to fluid and connected fracture geometry and volume variation

Comments:

Matching of double porosity pressure derivative data has to be done with buildup type curves in most cases as they exhibit different sensitivities to double porosity parameters than drawdown cases.

Negative skin and high wellbore storage indicates fissured reservoir, even if homogenous behaviour is observed on pressure and derivative plots. Usually longer duration is required for the double porosity behaviour to be exhibited.

8.

Geotechnique 35, 483 (1985)

1985

Permeability Tensor for Discontinuous Rock Masses

Authors: Oda M.

Contribution to the understanding of flow in naturally fractured reservoirs:

Development of the permeability tensor theory for fractured reservoirs.

Objective of the paper:

To study and develop a method to evaluate the naturally fractured formation permeability on various directions.

Methodology used:

Permeability tensor theory

Main Conclusions:

More geologically realistic reservoir models taking into account permeability anisotropy on various directions.

Comments:

Basis for integration of the Discrete Fracture Network modelling and Double Porosity analytical solving models. Bringing more accurate reservoir predictions.

9.

SPE-18173-MS

1988

Well test interpretation for Naturally fractured reservoirs

Authors: Stewart G., Asharsobbi F.

Contribution to the understanding of flow in naturally fractured reservoirs:

Validation of the pseudo-steady state model of matrix block support and interporosity skin due to fracture face alternation. New type curve for pressure derivative analysis.

Objective of the paper:

To study negative pseudo skin behaviour in pressure transient tests of double porosity fissured reservoirs.

Methodology used:

A new developed dimensionless derivative type curve.

Main Conclusions:

Negative pseudoskin of wellbores connected to fracture network

Comments:

Confirmation of validity from empirical negative pseudo-skin assumption of Gringarten A.C. on {JPT Apr. 1984 549-564}.

10.

PhD thesis, Stanford University

1989

Hydraulically fractured wells in heterogeneous reservoirs: Interaction, Interference and optimisation

Authors: Meehan D.N.

Contribution to the understanding of flow in naturally fractured reservoirs:

Hydraulically fractured wells and parallel natural fractures have minor productivity effect

Objective of the paper:

To study the interaction and interference of hydraulic fractures with pre-existing natural fractures in non homogenous reservoirs.

Methodology used:

A new developed dimensionless derivative type curve.

Main Conclusions:

Hydraulically fractured wells and parallel natural fractures have minor productivity effect

Comments:

Hydraulically fractured wells have optimum performance when the wellbore or the induced fractures intersect the existing natural fractures and are less or not affected by fractures not connected to wellbore or fractures if the reservoir matrix permeability is not high (common for carbonate matrix blocks).

11.

SPE-62498-PA

2000

Integration of Discrete Fracture Network methods with Conventional Simulator approaches

Authors: Dershowitz B., LaPointe P., Eiben T.

Contribution to the understanding of flow in naturally fractured reservoirs:

Development of techniques to integrate connectivity and scale dependent heterogeneity of Discrete Fracture Network modelling with Dual Porosity analytical and numerical simulation models.

Objective of the paper:

Integration of dual porosity model and Discrete Fracture Network modelling

Methodology used:

Discrete Fracture Network modelling, directional fracture system permeability model by Oda "Permeability Tensor for Discontinuous Rock Masses" (1984) Geotechnique 35, 483.

Main Conclusions:

The DFN models make reservoir modelling more geologically realistic, deriving parameters for the DP continuum models used in for DP reservoir simulation. DFN adds a tensor parameter to permeability calculations and an estimation of anisotropy, both by numerical simulation and increasingly complex analytical solutions.

Comments:

Permeability tensor is important on deciding the direction of wells to be drilled. Seismic surveys and existent well test data will contribute in optimising well completion planning.

12.

Elsevier publishing
ISBN 978-0-88415-317-7

2001

Geologic Analysis of Naturally Fractured Reservoirs

Authors: Nelson R.A.

Contribution to the understanding of flow in naturally fractured reservoirs:

Categorisation of naturally fractured reservoirs and their geological and flow properties

Objective of the paper:

To classify the fractured reservoir types according to their flow properties and establish general reservoir performance guidelines

Methodology used:

Already existing geological interpretation techniques and flow models for dual porosity models

Main Conclusions:

There are four different types of fractured reservoirs with different effect of fractures and their orientation on reservoir performance and development options.

Comments:

Categorization of fractured reservoirs based on their flow properties.

13.

Journal of Volcanology and Geothermal research 148 (200)
116-129

2005

Estimating flow heterogeneity in natural fracture systems

Authors: Leckenby R.J, Sanderson D.J., Lonergan L.

Imperial College London Department of Earth Science

Contribution to the understanding of flow in naturally fractured reservoirs:

Review of fracture flow properties, study on fault type effects on natural fractures orientation, network and flow patterns. Case study from western England basin, relevant to this project's studied reservoir.

Objective of the paper:

Estimation of flow heterogeneity in naturally fissured reservoirs from a geological perspective.

Methodology used:

Already existing geosciences techniques. The fracture fluid flow is approximated as a prismatic tube with smooth walls and calculated using the cubic flow law (Lomize 1951, Witherspoon et al. 1980).

Main Conclusions:

There are four different types of fractured reservoirs with different effect of fractures and their orientation on reservoir performance and development options.

Comments:

Assumption that the permeability of a rock mass increases as a function of fracture density for homogenous fracture networks. Neglecting the fracture boundaries roughness effects on fluid flow.

14.

SPE-138404

2010

New Method of Well Test Analysis in Naturally Fractured Reservoirs Based on Elliptical Flow

Authors: Igbokoyi A.O., Tiab D.

Contribution to the understanding of flow in naturally fractured reservoirs:

Direction of fluid flow prediction in naturally fissured reservoirs

Objective of the paper:

Application of elliptical flow model to predict the direction of the fluid flow in a fracture reservoir relative to the well locations and the fracture network properties and anisotropy.

Methodology used:

Use of Elliptical flow interpretation model for quantifying the permeability anisotropy in naturally fractured reservoirs. The TDS method for estimating elliptical radial coordinate (Tiab et al.)

Main Conclusions:

The elliptical flow model is the most appropriate for analyzing pressure transient data in fractured reservoirs.

The interpretation method provides a range of permeability and a direction of maximum permeability.

Comments:

The elliptical flow model is applicable to both high and low permeability anisotropy, while radial flow model is accurate only when permeability ratio is near or equal to unity.

15.

SPE-152019

2012

New Method of Well Test Analysis in Naturally Fractured Reservoirs Based on Elliptical Flow

Authors: Martin A.R., Cramer D.D., Nunez O., Roberts N.R.

Contribution to the understanding of flow in naturally fractured reservoirs:

A practical and mature methodology in order to perform injection fracturing shut in pressure transient tests in multiple formations within the same wellbore.

Objective of the paper:

Application of elliptical flow model to predict the direction of the fluid flow in a fracture reservoir relative to the well locations and the fracture network properties and anisotropy.

Methodology used:

Fracture injection shut in tests, with bottomhole pressure gauges simultaneously for various formations in the same well.

Main Conclusions:

Fracture injection shut in pressure transient tests yield reservoir properties and minimum horizontal stress direction, which assists to appraise the fracture network qualitative properties.

Comments:

It can be used for investigating and predicting the natural fractures orientation and distribution in the reservoir case study. It has a different pressure derivative interpretation technique, compared to classical build-up and drawdown tests.

Appendix B: Interpretation model history match

Objective: This section illustrates the match of the interpretation model with pressure data history based on the deconvolved derivative analysis and the rate correction by the algorithm.

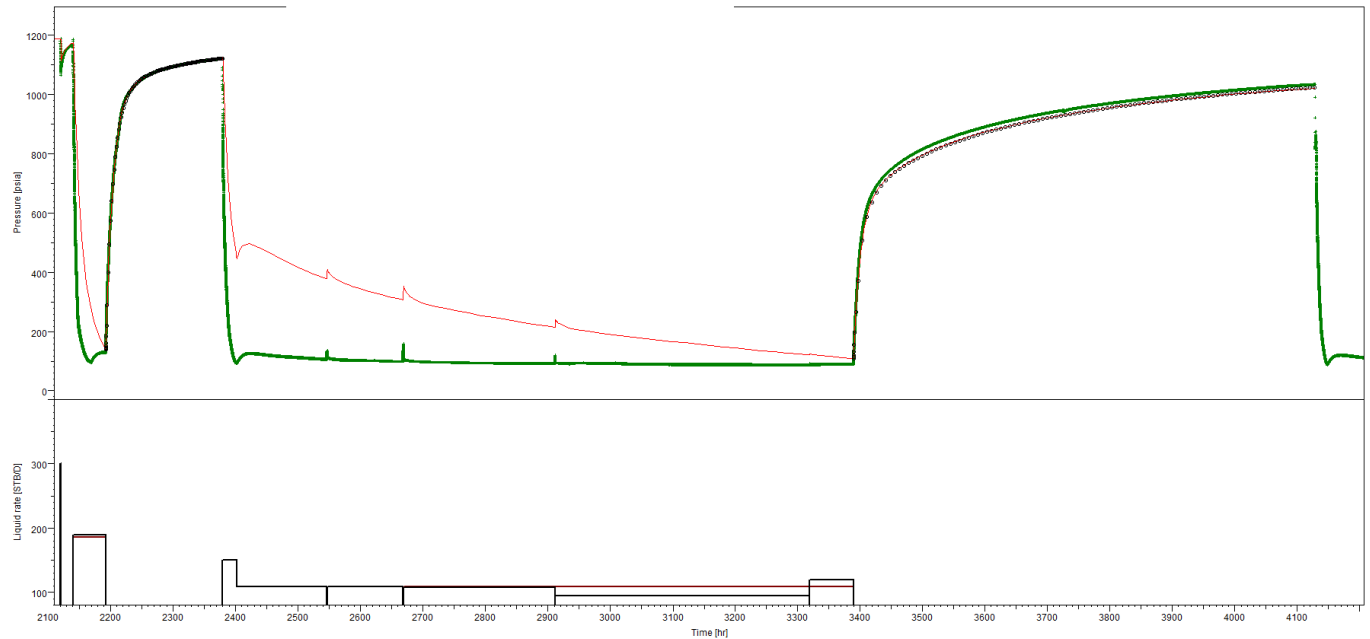


Fig. B- 1: History match of deconvolved derivative interpretation model

The drawdown flow periods' pressure data do not match with the model due to non reservoir effects and the fact that the well is let to load for the well flowing pressure to decrease, before the artificial lift initiates. As the well is not able to flow freely to the surface, the well flowing pressure (p_{wf}) is left to decrease prior to initiation of the beam pump.

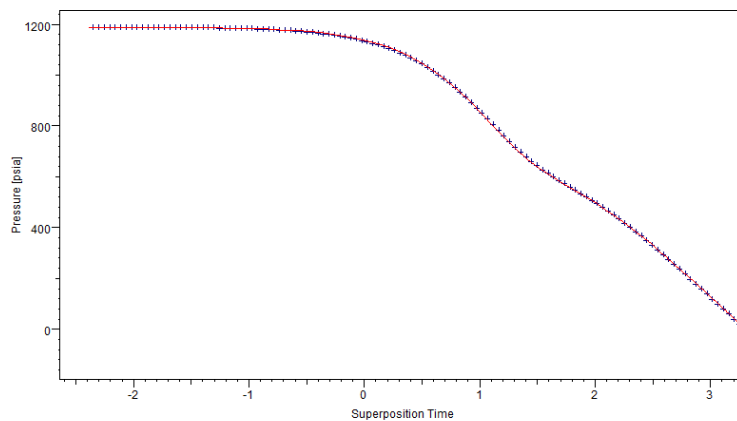


Fig. B- 2: Semi-Log plot of deconvolved drawdown pressure over superposition time

Appendix C: Propped Fracture Design Optimisation

Objective: This section illustrates the process of optimising a propped fracturing stimulation.

Unified Fracture Design: The method was developed by Economides et al. (2001), as a guideline for the design of propped fracture stimulation. The dimensionless fracture conductivity (C_{fD}) is defined in Eq. 15 as the ratio of the ability of the fracture to deliver fluid to the wellbore to the ability of the matrix to deliver fluid to the fracture. In order to achieve the maximum production increase, the optimum balance between the propped fracture and formation “deliverability” has to be found.

The proppant number (N_p) range is a dimensionless fracture design, reservoir shape and permeability dependent factor (Eq. 16,17). Based on its value, the following recommendations have been developed:

$$C_{fD,opt} = 1.6 \quad N_p < 0.1 \dots\dots\dots (C- 1)$$

$$C_{fD,opt} = 1.6 + e^{\frac{-0.583+1.48 \ln N_p}{1+0.142 \ln N_p}} \quad 0.1 < N_p < 10 \dots\dots\dots (C- 2)$$

$$C_{fD,opt} = N_p \quad N_p > 10 \dots\dots\dots (C- 3)$$

Therefore, by definition the optimum length and width solve the following equation:

$$\frac{w_{opt}}{x_{f,opt}} = C_{fD,opt} \frac{k}{k_f} \dots\dots\dots (C- 4)$$

The maximum attainable productivity index can be calculated as follows:

$$J_{D,max} = \frac{1}{0.99-0.5 \ln N_{p,e}} \quad N_{p,e} \leq 0.1 \dots\dots\dots (C- 5)$$

or

$$J_{D,max} = \frac{6}{\pi} - e^{\frac{0.423-0.311N_{p,e}-0.089N_{p,e}^2}{1+0.667N_{p,e}+0.015N_{p,e}^2}} \quad N_{p,e} > 0.1 \dots\dots\dots (C- 6)$$

Where $N_{p,e}$ (Dietz, 1965) represents the proppant number adjusted for Dietz shape factor (C_A)

$$N_{p,e} = N_p \frac{C_A}{30.88} \dots\dots\dots (C- 7)$$

The optimal fracture conductivity ($C_{fD,opt}$), proppant number, fracture width (w_{av}) and half-length (x_f) are approximated iteratively.

Appendix D: Test interpretation from another well

Objective: This section presents interpretation results on another DST performed on the same formation. Radial flow stabilisation was not reached within any flow period, therefore an interpretation apart from near wellbore effects subject to uncertainty and does not provide solid appraisal base.

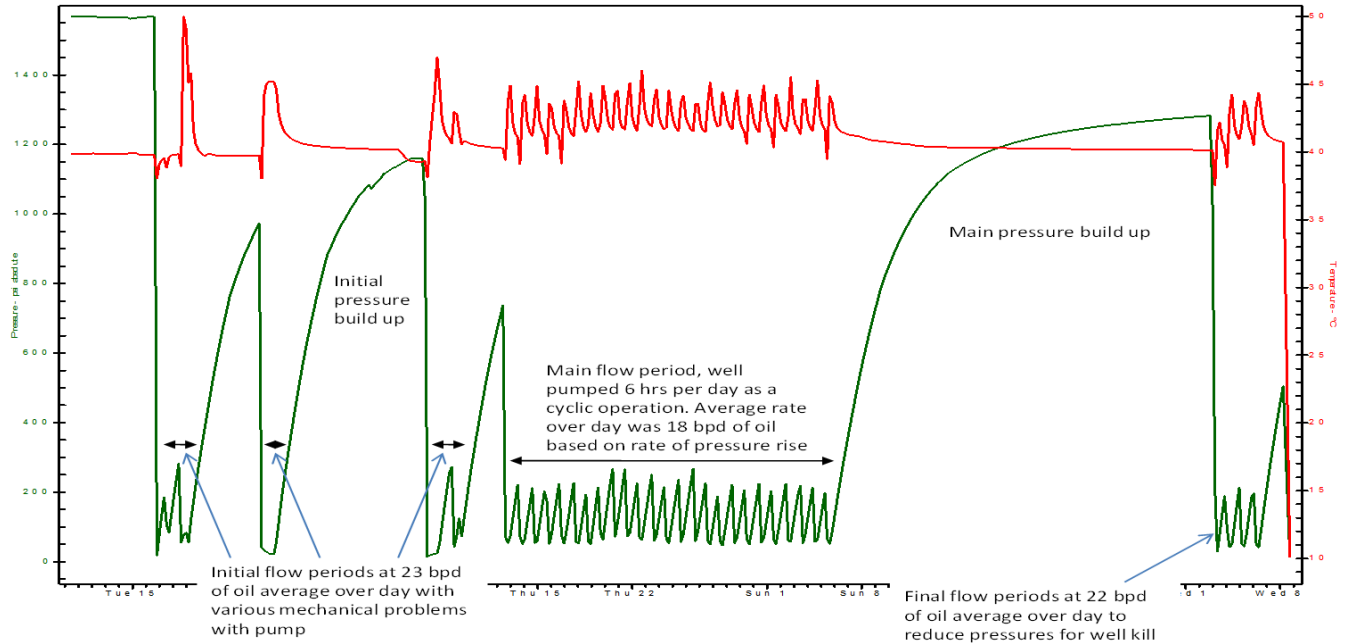


Fig. D- 3: Well test design for second well

Deconvolution was deemed unsuccessful due to a lot of non-reservoir effects on the secondary buildup flow periods. The production flow periods were unsuitable for inclusion to the algorithm due to cyclical operation of the beam pump as a result of low daily production rates. Moreover, connection to lower reservoirs is suspected to be caused due to well integrity issues, due to the large difference in reservoir pressure compared to the main test of this study.

Interpretation was made using a double porosity model for a single producing layer with assumed thickness of 20 ft. Time dependent skin was used to match the pressure history (Fig. D-3). The only parameters that may be identified with some confidence are wellbore storage and skin. Analysis indicated that the Bourdet derivative values match with the same storativity ratio value from the other well. This can be used only as an indication, as the end of Interporosity flow transition and infinite acting radial flow are not reached within the test duration.

Table D- 1: Test results from the longest buildup Analysis

| p_i [psia] | WS [bbl/psi] | S | h [ft TVD] | ϕ [%] | kh [mD•ft] | k [mD] | λ | ω | PI [stb/psi-d] |
|--------------|--------------|-------|------------|------------|------------|--------|-------------------|----------|---------------------|
| 1400 | 0.056 | -1.75 | 20 | 15 | 36 | 1.8 | $9 \cdot 10^{-6}$ | 0.15 | $1.5 \cdot 10^{-2}$ |

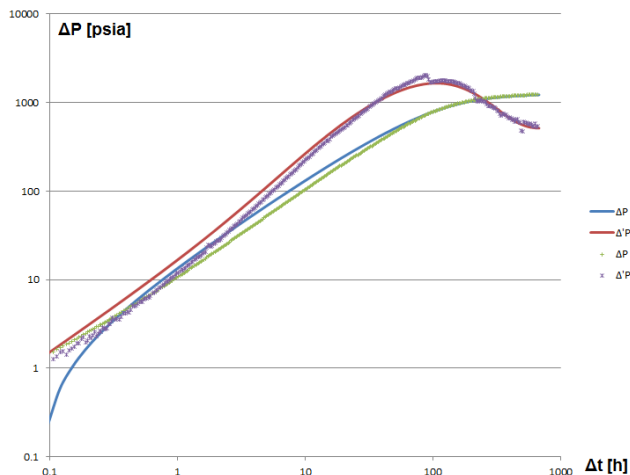


Fig. D- 4: Log-Log Pressure and Derviative match

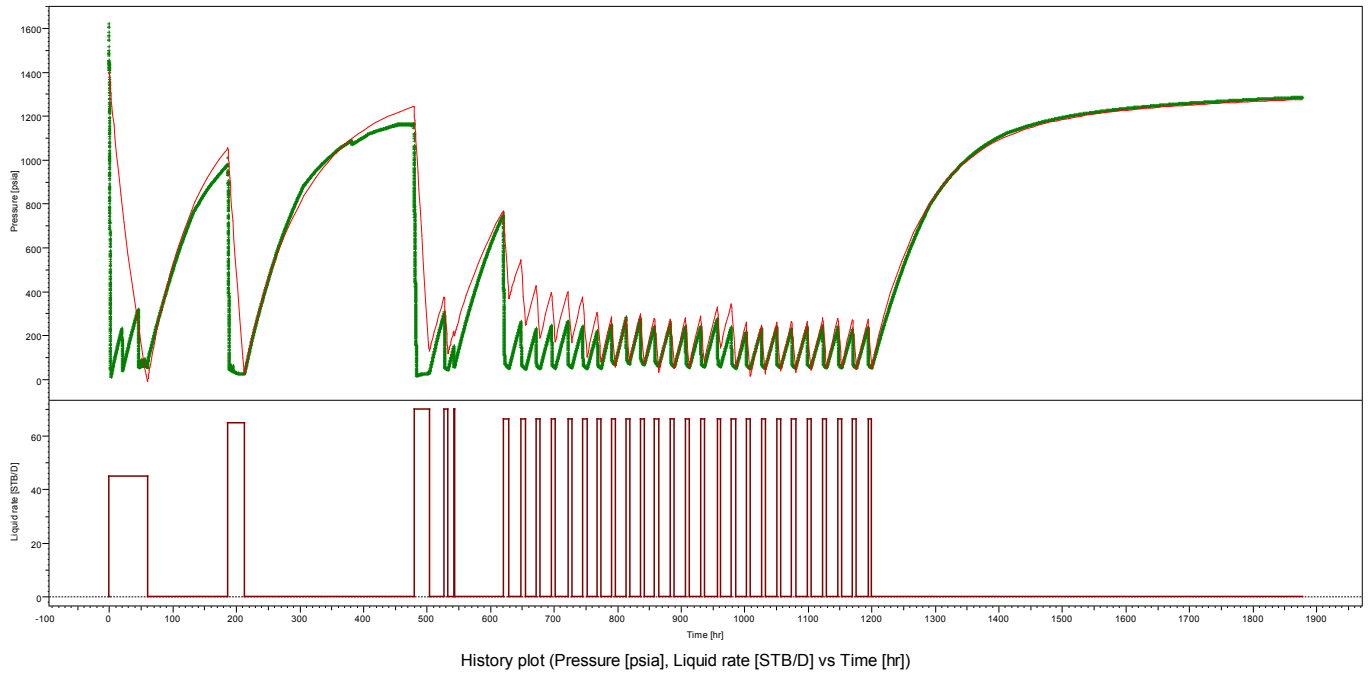


Fig. D- 5: Test History Match

Brine was used to kill the well prior to this drill stem test. A time dependent skin interpretation with higher values for the initial flow periods was used, to account for the initial two phase oil and brine flow period, which aided in obtaining an acceptable pressure history match (Fig. D-3).

Appendix E: Well Deviation Survey for Tested Well

Objective: This section illustrates the well trajectory and deviation from the vertical direction.

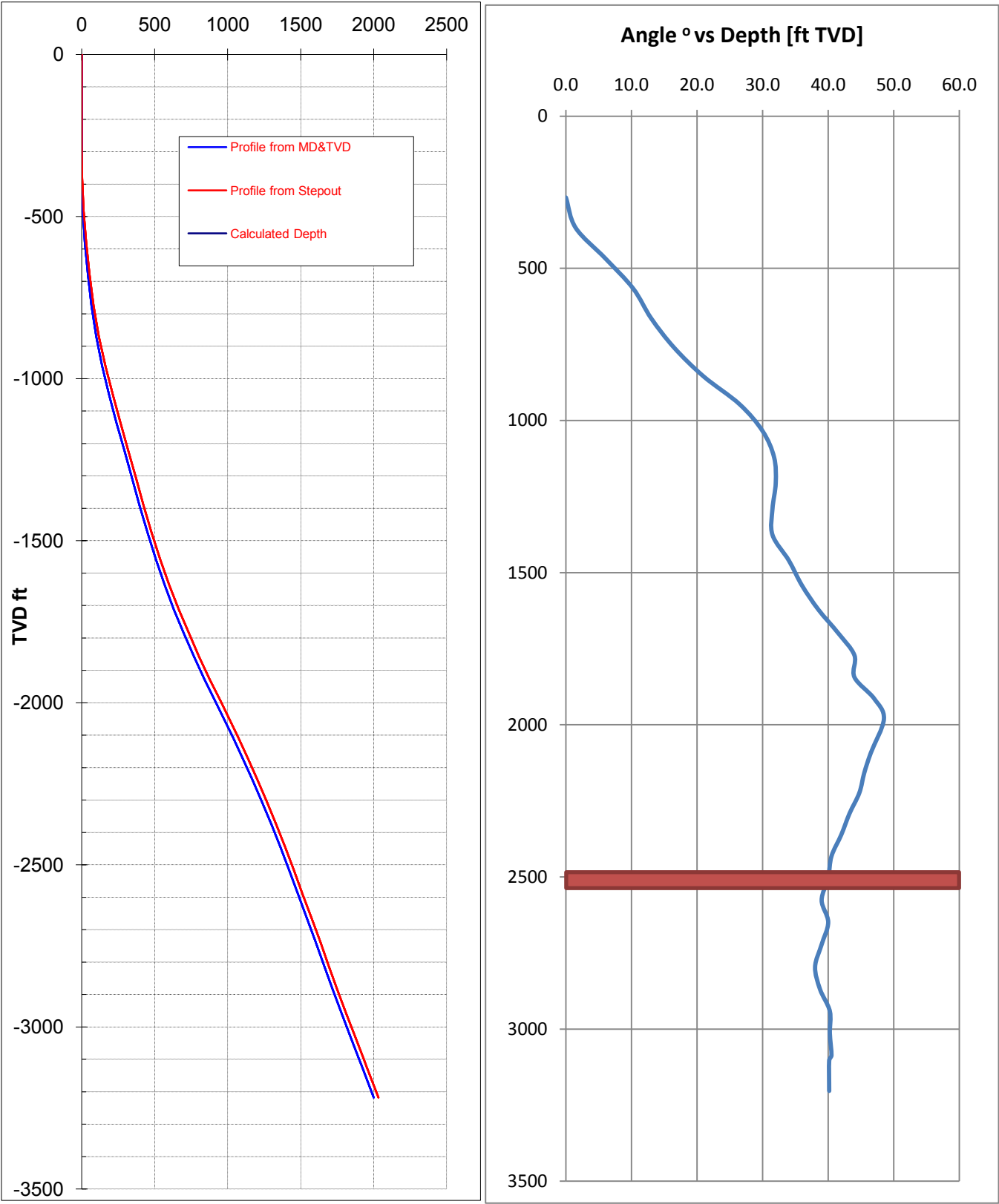


Fig. E- 1: Well Deviation from vertical direction and deviation angle vs depth.

Appendix F: Test Sensitivities to double porosity parameters

Objective: This section presents the sensitivity of the drawdown derivative to double porosity parameters

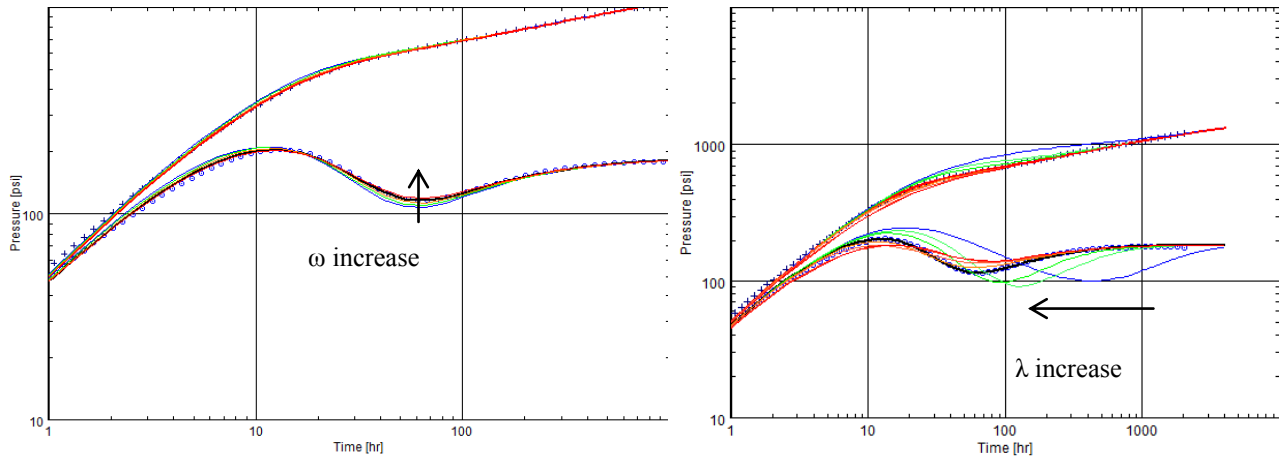


Fig. F- 1: Sensitivity to Storativity ratio (ω) and Interporosity flow parameter (λ)

The storativity ratio is defined from Eq. 1:

$$\omega = \frac{(\phi V c_t)_f}{(\phi V c_t)_{f+m}} = \frac{(\phi V c_t)_f}{(\phi V c_t)_f + (\phi V c_t)_m} \dots \dots \dots (F- 8)$$

As the total compressibility is assumed the same for fracture and matrix and the fracture porosity is equal to unity:

$$\omega = \frac{V_f}{V_f + \phi_m} \dots \dots \dots (F- 2)$$

From Eq. F-2 we obtain Eq. 2, correlating the fracture volume with the matrix porosity.

Values of the storativity ratio with order of magnitude 10^{-2} indicate a reservoir fissured in multiple directions, while values in the range of $[10^{-1}, 2 \cdot 10^{-1}]$ indicate layered parallel fractures as seen in Fig. F-2 (Gringarten, 2010).

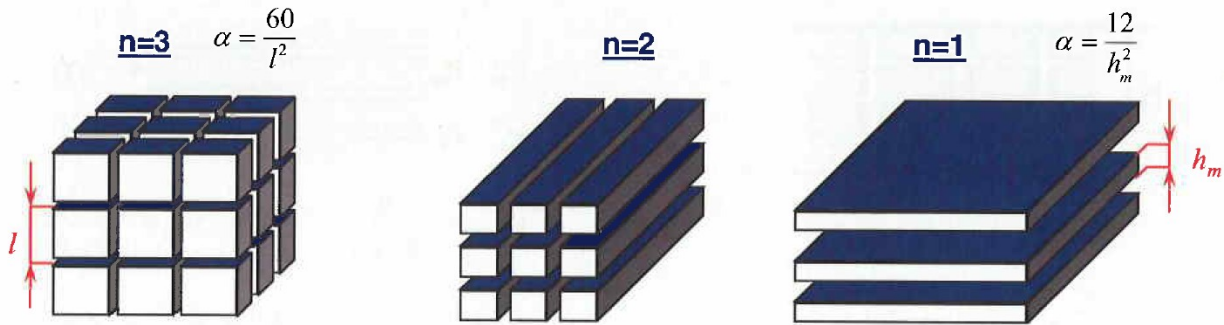


Fig. F- 2: Fissured reservoir types (Gringarten, 2010)

The case studied corresponds to a layered double porosity system for $n = 1$, for which the corresponding Eq. 5 is obtained.

Appendix G: Petrophysical Interpretation

Objective: This section provides an overview of the petrophysical interpretation process based on the available wireline logs.

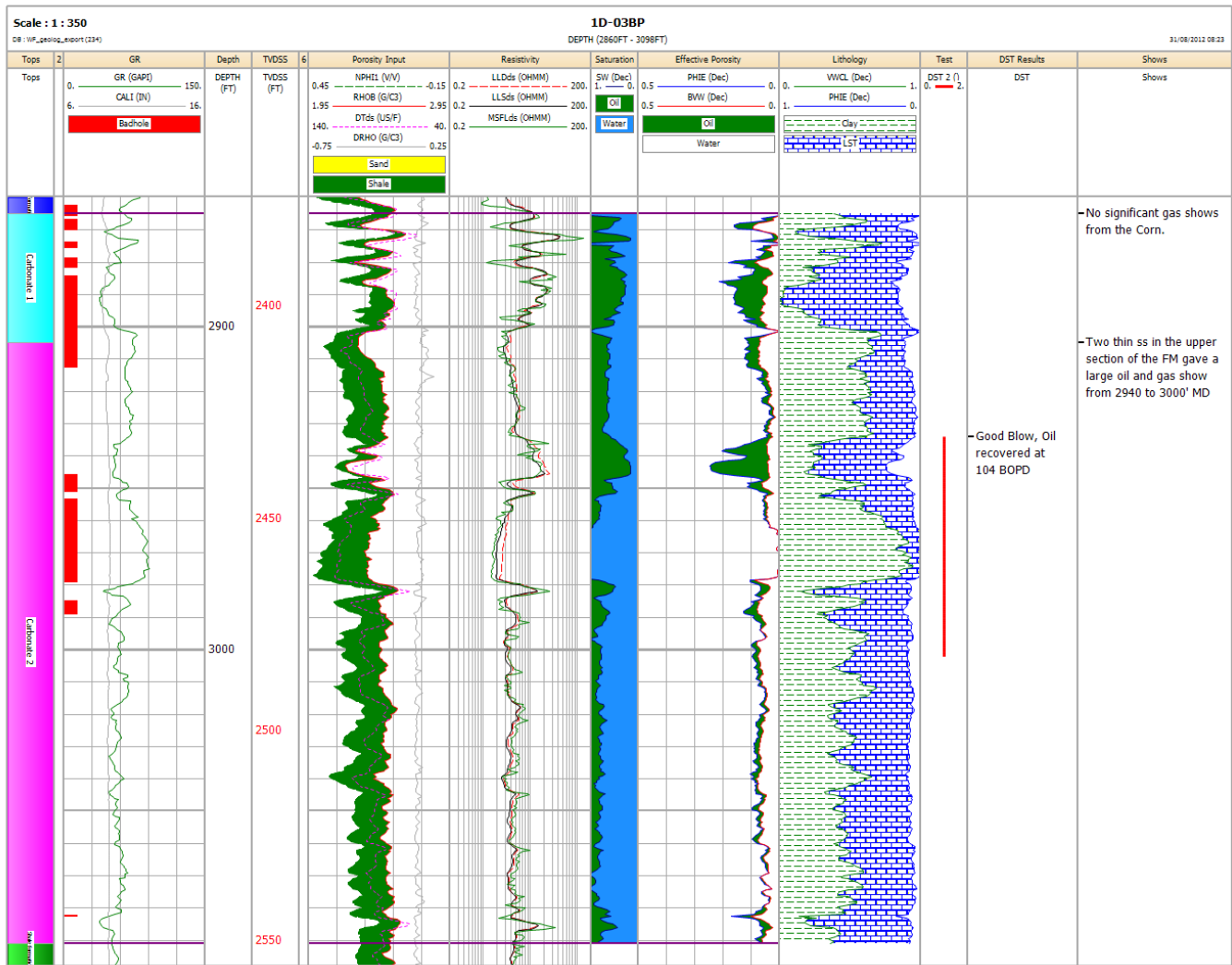


Fig. G- 1: Petrophysical interpretation of well 1D-03 which was tested

The petrophysical evaluation was performed on multiple wells, including the one corresponding to the case study (Fig. G-1) with a deterministic approach. Initially there was performed a quality check of the input logs.

Through a comparison between the calliper measured borehole diameter and the bit size, a “bad-hole” discriminator is set up. The effect on filtering measured bulk density and neutron porosity dispersion is beneficial, as illustrated in Fig. G-2.



Table G-2: Mineralogical Analysis

The formation water salinity (80,000 ppm) was determined using water analysis and used to calibrate the resistivity R_w selected for fluid saturation interpretation (Fig. G-3).

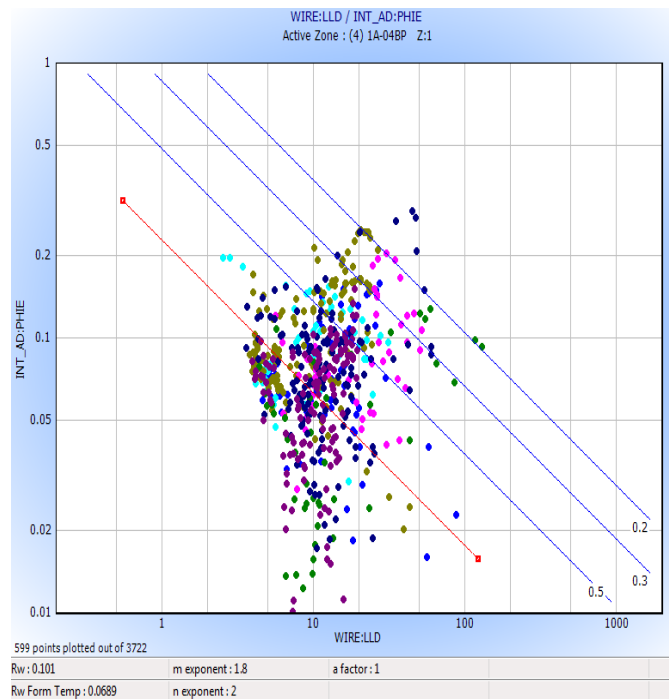


Fig. G- 3: Interpreted porosity to wireline LLD resistivity

Appendix H: Fracture Injection test falloff interpretation

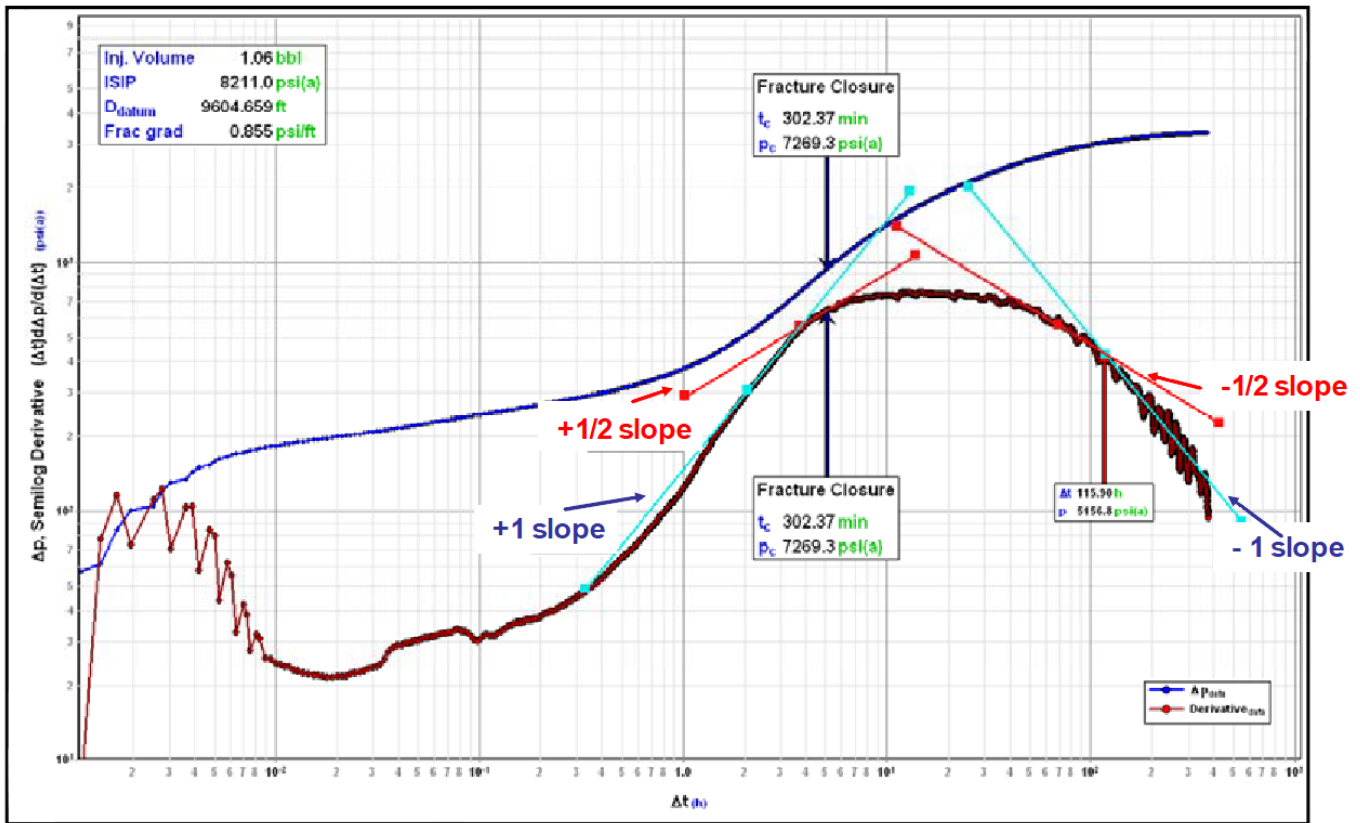


Fig. H- 1: Fracture Injection Test example (Martin et al. 2012)

An interpretation example of a fracture injection test pressure and semi-log derivative over time logarithmic plot is presented in Fig H-1. The derivative plot shows characteristic slopes that indicate the pressure response is strongly influenced by various flow regimes. Positive trending slopes on the semi-log derivative occur during fracture closure period. The positive unit slope is characteristic of wellbore or fracture storage, indicating that a closing secondary fracture set is supplying fluid to the primary fracture. Fracture height recession and closing transverse fractures are two potential fracture storage mechanisms (Baree et al. 2007). The positive $\frac{1}{2}$ slope trend is indicative of linear flow and suggests the presence of an open fracture. A departure from the positive $\frac{1}{2}$ slope suggests that the fracture has closed. Negative trending slopes occur during the after closure and verify that closure has occurred. The negative $\frac{1}{2}$ slope and unit slope trends are characteristic of pseudo-linear and pseudo-radial flow, respectively (Martin et al. 2012).