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DYNAMIC MATERIAL BALANCE IN A NATURALLY FRACTURED GAS-CONDENSATE RESERVOIR WITH WATER INFLUX: FIELD CASE STUDY

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RESUMEN

El método de Balance de Materia es ampliamente aceptado como la técnica para determinar hidrocarburos in-situ, comparado con estimaciones volumétricas. Este requiere de análisis PVT, producción acumulada e historial de presión promedio de reservorio buscando calcular una solución significativa. En la práctica, los datos de presión pueden ser dispersos o inexistentes para un determinado reservorio debido a varias razones, tales como problemas operacionales, demanda de producción, altos caudales de agua y otros, que hacen no factible cerrar el pozo para realizar una prueba de presión.
Sin embargo, las pruebas de producción y medidas de presión de fondo fluyente es información usualmente disponible. Puede ser utilizada como datos alternativos para el cálculo de volúmenes in-situ de hidrocarburos, como fue demostrado por la formulación del Balance de Materia Dinámico. Este método a pesar de estar basado en ecuaciones robustas, ha sido desarrollado considerando reservorios homogéneos.
Un reservorio naturalmente fracturado puede comportarse como homogéneo, dependiendo del grado de heterogeneidad y el tiempo de producción. Métodos de análisis de producción han sido aplicados para analizar reservorios fracturados utilizando software comercial. Sin embargo, la relevancia de esta aplicación para el cálculo de volumen in-situ no ha sido evaluada todavía.
El propósito de este artículo es el de evaluar la aplicabilidad del balance de materia dinámico en reservorios de gas-condensado naturalmente fracturados. Se presenta una extensión de este método para reservorios naturalmente fracturados, asumiendo un reservorio cerrado y un modelo doble porosidad de flujo interporoso pseudo-estable. Adicionalmente se describe, para el caso de estudio, una metodología práctica para corregir el volumen in-situ de gas por intrusión de agua. Los resultados confirmaron el uso de este método para la estimación de volumen in-situ en reservorios heterogéneos.

INTRODUCTION

The estimation of hydrocarbon-in-place and reserves is crucial to determine the economic viability of a field development project. There are different methods that can be applied with this purpose, such as: volumetric, material balance, production data analysis, pressure transient analysis and numerical reservoir simulation. The selection of the method depends on the quantity and quality of available information.

Conventional material balance is still considered one of the most reliable methods to estimate hydrocarbons in-place. It requires fluid properties information, cumulative production and reservoir average pressure history. The static average reservoir pressures are generally obtained performing buildup tests (which require to shut-in the well). However, the access to this information is not feasible in active water drive gas reservoirs due to drowning risk, therefore conventional material balance might not be applicable.

On the other hand, modern Production Data Analysis (PDA) techniques analyze the behavior of flowing pressures (surface or bottomhole) and flow rates. This information is related to reservoir depletion assuming a pseudo-steady state flow regime, and it is used to determine hydrocarbon-in-place. Nevertheless, it could be used for the case of water drive gas reservoirs. There are several PDA methods such as: Blasingame type curve, Argawal-Gardner Type Curve, NPI method, and Dynamic Material Balance.

Dynamic Material Balance (DMB) was chosen for this work for being considered a type curveless and straight-forward method. DMB was founded in Blasingame and Lee work (1986), which presented an alternative approach to estimate the drainage area and shape of the reservoir for "variable rate" production data. It was based on material balance time definition, which account for changing operating conditions.

Mattar and McNeil (1998) proposed the "Gas Flowing Material Balance" method for volumetric reservoirs producing at a constant rate. Next, Mattar and Anderson (2005) extended the application for variable flow rate case, under the name of "Dynamic Material Balance". This method was developed for volumetric oil and gas reservoirs; however they suggested its application in water drive reservoirs with proper correction by water influx.

Gerami *et al* (2007) verified the use of pseudo-time and normalized material balance pseudo-time in Naturally Fractured Reservoirs (NFR). They presented a model where storativity ratio (ω) is pressure dependent and varies through time. However, the error in calculation of bottomhole flowing pressures would be smaller if extrapolation is based on initial data points, close to initial reservoir pressure.

Al-Reshedam *et al.* (2012) and Fernandez-Berrios (2012), provided examples of the application of DMB in hydraulically fractured oil wells and low permeability gas wells, respectively. Ismadi *et al.* (2005) compared the methods of static (conventional) and dynamic material balance and obtaining similar results.

Heidari *et al.* (2013) presented an approach for gas-condensate reservoirs using two-phase compressibility factor (Ztp). They rewrote the equations as a function of gas and condensate rates and CVD analysis (do not require flowing pressures). Results were validated using synthetic numerical models and real field cases. Arabloo *et al.* (2014) defined a new adjusted pressure and a modified material balance pseudo-time as a function of the same two-phase compressibility factor.

Hosein Zareenejad *et al.* (2012) presented a field case study of Fetkovich, Argawal-Gardner (A-G) and Blasingame type curves to evaluate NFR. They concluded that A-G and Blasingame type curves provide acceptable values of permeability compared to transient well test analysis. In contrast, Adrian (2015) demonstrated that PDA methods, based on homogeneous reservoirs, might be applicable to evaluate reservoir parameters only in NFR with transient interporosity flow. NFR with pseudo-steady state interporosity flow requires a correction to avoid errors in the estimation of these parameters.

The purpose of this paper is to describe the application of DMB to determine the OGIP in naturally fractured gas-condensate reservoirs with water influx. An extension of this method assumes a dual porosity model with pseudo-steady state interporosity flow. In addition, it describes a practical methodology to correct Original-Gas-in-Place (OGIP) by water influx using Moghadam *et al* (2011) method. A field case study of DMB in a NFR with water influx is presented.

METHODOLOGY

Dynamic material balance was developed based on the solution of diffusivity equation for constant rate and pseudo-steady state (PPS) flow regime (Eq.1). This production scenario assumes that the reservoir limit is sealed and the pressure drop is constant through time from reservoir limit to the wellbore:

$$P_D = \frac{2t_D}{{r_{e_D}}^2} + ln\left(r_{e_D}\right) - \frac{3}{4} + s. \tag{1}$$

This equation can be expressed in the dimensional form for single gas phase, using pseudo-pressure and pseudo-time definitions, wellbore skin and considering volumetric reservoir, by the following equation Mattar and Anderson:

$$m(P_i) - m\left(P_{wf}\right) = \frac{2P_i q_g t_a}{\left(\mu_{g_i} c_{g_i}\right) z_i \boldsymbol{G}} + \frac{1.417\times10^6 q_g T}{kh}\left[ln\left(\frac{r_e}{r_{wa}}\right) - \frac{3}{4}\right]. \tag{2}$$

Naturally fractured reservoirs, requires a more complex model to account for matrix and fracture systems behavior. Several mathematical models have been proposed, however dual porosity model is still one of the more accepted and used in petroleum industry. It considers two interporosity flow models: Transient and Pseudo-steady state.

Even though, transient flow is the more probable flow regime from matrix to fractures, however in late times PSS should be achieved (Lee *et al* 2003). Mavor and Cinco Ley (1979) agreed that PSS model is a reasonable idealization of the matrix and fracture behavior. For instance, the solutions of diffusivity equation for dual porosity systems considering a constant flow rate, PSS interporosity flow, and a closed circular reservoir, presented by Da Prat (1990), and including the wellbore skin would be:

For fracture system: $0.1 \leq t_{D_f} \leq \frac{\omega(1-\omega)}{\lambda}$

$$P_{fw_D} = \frac{2t_D}{\omega\, r_{e_D}{}^2} + ln\left(r_{e_D}\right) - \frac{3}{4} + s \quad (3)$$

For total system: $t_{D_f} \geq \frac{\omega(1-\omega)}{\lambda}$

$$P_{fw_D} = \frac{2t_D}{r_{e_D}{}^2} + ln\left(r_{e_D}\right) - \frac{3}{4} + s + \frac{2(1-\omega)^2}{\lambda\, r_{eD}{}^2} \quad (4)$$

The solutions for fracture and total system can be represented by Eqs. 3 and 4 for $\frac{t_{AD}}{\omega}$ >0.1, which defines the condition to reach the reservoir boundaries (dimensionless definitions in Appendix A). The application of these equations depends on the value of the dimensionless time for dual porosity system (t_{Df}), the storativity ratio ω and interporosity coefficient λ. Essentially, a short time test only fracture volume is influenced by wellbore pressure drop. In contrast, a long time test, wellbore pressure behavior will be in contact with the total system volume (fractures + matrix). Storativity ratio and interporosity coefficient might be obtained through pressure transient analysis (PTA).

Equations 3 and 4 can be expressed in the dimensional form through a similar procedure made by Mattar and Anderson. It considers a single gas phase, pseudo-pressure definition and volumetric reservoir. According to Gerami *et al* research, the difference in calculating bottomhole pseudo-pressures, for a constant or variable ω, is negligible at wellbore pressures near initial reservoir pressure (which is the case of a water drive mechanism). Therefore, for this approach a constant ω will be assumed:

For fracture system:

$$m(P_i) - m\left(P_{wf}\right) = \frac{2\, P_i q_g t_{ca}}{\mu_{g_i}\, c_{g_i}\, Z_i\, \omega G} + \frac{1.422{\times}10^6\, q_g T}{k_f\, h}\left[ln\left(\frac{r_e}{r_{wa}}\right) - \frac{3}{4}\right] \quad (5)$$

For total system:

$$m(P_i) - m\left(P_{wf}\right) = \frac{2\, P_i q_g t_{ca}}{\mu_{g_i}\, c_{g_i}\, Z_i\, G} + \frac{1.422{\times}10^6\, q_g T}{k_f\, h}\left[ln\left(\frac{r_e}{r_{wa}}\right) - \frac{3}{4} + \frac{2(1-\omega)^2 r_{wa}{}^2}{\lambda\, r_e{}^2}\right] \quad (6)$$

Where:

$$t_{ca} = \frac{(\mu_{g_i} c_{g_i})}{q_g} \int_0^t \frac{q_g dt}{\overline{\mu c_g}} = \frac{(\mu_{g_i} c_{g_i})}{q_g} \frac{Z_i G}{2P_i} \left(m(P_i) - m(\overline{P}) \right) \tag{7}$$

$$G = \frac{(\phi_f + \phi_m)\, \pi r_e^2 h P_i T_{sc}}{Z P_{sc} T} \tag{8}$$

n Eq. 5, the term "ω*G*" would be the OGIP of the fracture system. Storativity ratio might be obtained from PTA, to calculate the OGIP of the total system. On the other hand, Eq. 6 is similar to homogeneous solution (Eq. 2), providing directly the total system OGIP. This would be the reason of obtaining acceptable results with the original DMB method.

Simplifying the Eq. 5 and 6 by defining b_{pss}, $\tilde{b}_{pss}$, and rearranging terms to express it as a straight line, they can be written in the simplest form as presented by Clarkson (2009):

For fracture system:

$$\frac{q}{m(P_i) - m(P_{wf})} = -\frac{1}{b_{pss}(\omega G)} \frac{G\left(m(P_i) - m(\overline{P})\right)}{\left(m(P_i) - m(P_{wf})\right)} + \frac{1}{b_{pss}} \tag{9}$$

For total system:

$$\frac{q}{m(P_i) - m(P_{wf})} = -\frac{1}{\tilde{b}_{pss}\,(G)} \frac{G\left(m(P_i) - m(\overline{P})\right)}{\left(m(P_i) - m(P_{wf})\right)} + \frac{1}{\tilde{b}_{pss}} \tag{10}$$

Where:

$$b_{pss} = \frac{1.417 \times 10^6 T}{kh} \left[ln\left(\frac{r_e}{r_{wa}}\right) - \frac{3}{4} \right] \tag{11}$$

$$\tilde{b}_{pss} = \frac{1.422 \times 10^6\, T}{k_f\, h} \left[ln\left(\frac{r_e}{r_{wa}}\right) - \frac{3}{4} + \frac{2(1-\omega)^2 r_{wa}^2}{\lambda\, r_e^2} \right] \tag{12}$$

The value of OGIP of fracture or total system, depending on the appropriate equation, can be determined through the same iterative procedure proposed by Mattar and Anderson. For a volumetric gas reservoir the general material balance equation (Eq. 13), which relates average reservoir pressure and OGIP (G) can be used with this purpose:

$$\frac{P}{Z} = \frac{P_i}{Z_i}\left(1 - \frac{Gp}{G}\right) \tag{13}$$

Assuming a first value of OGIP (i.e. GV from volumetric method), P/Z, averages reservoir pressure and pseudo-pressure values can be calculated for each cumulative production. A plot of $\frac{q_g}{(m(P_i)-m(P_{wf}))}$ vs. $G\frac{(m(P_i)-m(\overline{P}))}{(m(P_i)-m(P_{wf}))}$, will give a new "G", that is used for the next iteration until obtain convergence.

It must be pointed out that, the estimated average reservoir pressures would correspond to the fracture system if $0.1 \leq t_{Df} \leq \frac{\omega(1-\omega)}{\lambda}$. For the second time interval $t_{Df} \geq \frac{\omega(1-\omega)}{\lambda}$, it would represent the average values of both systems (fracture system and matrix system reservoir pressure).

On the other hand, an important consideration of modern PDA methods is that formation and well properties affecting flow are constant through time (permeability and skin). Even though the skin value is considered in the solution, it seems that in PDA methods this value is almost qualitative (HoseinZareenejad *et al.*). In contrast to PTA, which provides more accurate values of permeability and skin, PDA methods are focused in long time production data, therefore their accuracy is related with reservoir size and shape (Khamal 2009).

For gas-condensate reservoirs, the two phase compressibility factor (Z_{tp}) is adopted for the two-phase region (below dew point pressure), to avoid understimation of GOIP (Rayes *et al* 1992). This includes the calculation of compressibility factor for bottomhole flowing pressures and average reservoir pressures. Heidari *et al.* also recommended the use of this correction.

Correction for Water Influx

As it is already known, an active aquifer influences the linear P/Z plot trend of volumetric reservoirs. It provides additional energy that supports the reservoir pressure, causing P/Z values to exhibit an upward trend. Therefore, the Moghadam *et al.* method (Advanced Material Balance) was selected to take into account water drive mechanism.

This method considers deviation of P/Z values due to different production drive mechanisms for gas reservoirs such as: water influx, abnormal pressure and gas desorption. Therefore, if one drive mechanism is not present, it can be neglected from the general equation. For the case of water influx, the equation will be:

$$\frac{P}{Z^{**}} = \frac{P_i}{Z_i}\left(1 - \frac{Gp}{G^{**}}\right) \tag{14}$$

Where:

$$Z^{**} = \frac{P}{\left[\left(\frac{P}{Z}\right)(1-C_{wip}S_{gi})\right]} \tag{15}$$

$$C_{wip} = \frac{\Delta V_{wip}}{\left(\frac{G\beta_{gi}}{S_{gi}}\right)} = \frac{5.615\ (W_e - W_p\beta_w)}{\left(\frac{G\beta_{gi}}{S_{gi}}\right)} \tag{16}$$

Once OGIP (G) from DMB is obtained from using Eq. 13, P/Z and average reservoir pressures are available data. The P/Z values can be corrected due to water influx using Eq. 14, and reservoir pressure values can be used to calculate cumulative water influx (We) with any analytical water influx model (i.e. Fetkovich model).

The corrected value of OGIP (G^{**}) is related to OGIP (G), from DMB, through the following relation:

$$\frac{G^{**}}{G} = \frac{1-\frac{(P/Z)}{(P/Z)_i}}{1-\frac{(P/Z^{**})}{(P/Z)_i}} \tag{17}$$

Finally, a plot of $\frac{q_g}{\left(m(P_i)-m(P_{wf})\right)}$ vs. $\left(\frac{G^{**}}{G}\right) G \frac{\left(m(P_i)-m(\overline{P})\right)}{\left(m(P_i)-m(P_{wf})\right)}$, will give the value of G^{**}.

Field Application: Case Study

The method was applied to a naturally fractured gas-condensate reservoir from Devonian age (sandstone). The structure is a faulted anticline limited by an inverse fault to the north and gas-water contact to the south. There is a fault “A” in the middle of the structure, which apparently divides the structure in two regions (“East” and “West”), nevertheless PTA confirmed that the fault has transmissibility (Fig. 1). Well 1 (West region) is approximately at 180 m from Fault “A”.

The formation was classified as a naturally fractured reservoirs type “A” (Aguilera 1995) according to PTA, production trend, regional geological description of Devonian sandstones and analogy to an adjacent field that produces from the same formation. The type “A” is characterized by having fractures with little fluid storage; however they contribute to production creating a preferential flow direction. These characteristics would be equivalent to type 3 according to Nelson classification (2001).

GOIP from Volumetric method (G_V)

There was just one well that could provide information (porosity, water saturation, net pay, etc.) for the volumetric estimation of OGIP. Unfortunately, specialized logging interpretation, pressure formation test and core analysis were not available due to operational issues. Therefore, Monte Carlo method was employed to estimate the OGIP (P10, P50 and P90), considering the total structure rock volume presented in Table 1.

Production History

At the time of analysis, the field had one producing well (Vertical Well 1) and a second well was being drilled (Well 2). Therefore, the available production data to be analyzed only belongs to Well 1 without well interference which is presented in Fig. 2. Well 1 was open to production for 90 days (first drawdown test) with a maximum gas flow rate of 5.7 MMscfd and high water-gas ratio of 30 STB/MMscf (171 BPD). Then the well was shut-in (36 days) waiting for the production line to be ready for production. The longer period of sustained production was between May-2012 to Jan-2013 (7.5 months, shaded-yellow area). Sub-critical flow effect (liquid load up) was identified in the last part of the test, and was considered for the analysis.

As can be seen in Fig. 2 only wellhead flowing pressure was available, therefore bottomhole flowing pressures needed to be calculated. According to Coax et al (2006), four multiphase vertical flow correlations were recommended for gas wells. Gray method (1978) was selected because it provided better approximation to real data measurements (dynamic pressure surveys) performed in February and April in 2012 (Fig. 3).

Data Selection for the Analysis

The production data analysis focused on the second drawdown presented in Fig. 4. At the beginning of the drawdown (May2012), there is a clean-up period where gas flow rate was increasing and water rate is decreasing. It was necessary to use nitrogen to put the well back in production after the last build-up. This data was not used for the analysis because it reflects wellbore behavior. During the 7.5 months of production, Water-Gas Ratio (WGR) and Condensate-Gas Ratio (CGR) showed slightly variation through the well lifetime. WGR increases from 33 to 51 STB/MMscf and CGR decreases from 108 to 100 STB/MMscf.

Static Pressure measurements

Reservoir pressure was measured in three opportunities using the top perforations (4479 m) as reference depth. The first one during the DST (Pr_1: 5890 psia Nov 2011), the second one after the well completion (Pr_2: 5778 psia) and the third one after the first drawdown test (Pr_3: 5651 psia – 5.5 days shut-in). Pr_2 and Pr_3 values are plotted in Fig. 3 at the gauge depth (4284 m). The drawdown test matched to a dual porosity model (pseudo-steady state matrix flow) as can be observed in the Semi log plot (Fig. 5). The following information was obtained from the PTA: k: 0.547 md; s: -4.3; storativity ratio ω: 0.0427 and interporosity flow coefficient λ: 6.297×10^{-8}.

As can be observed, the presence of an active aquifer is supported by water production, structural geology and the high productivity of the well despite water production. The last one is related to an external pressure support, confirmed by Cole diagnostic plot (Pletcher 2002), using the available reservoir pressures (Fig. 6). Additional reservoir and aquifer information is presented in Table 2.

Dynamic Material Balance with water influx

The first step was to determine which equation to apply according to the value of dimensionless time for a production time of 7.5 months (227 days). The corresponding dimensionless time and term $\frac{t_{AD}}{\omega}$ were 8.22×10^6 and 11.16 respectively for a wellbore skin of "-0.5" (indicating also well stimulation). In this case, dimensionless time is greater than $\frac{\omega(1-\omega)}{\lambda}$ $=6.49 \times 10^5$, therefore the time was enough to reach the pseudo-steady state of the total system and Eq. 10 must be applied.

The use of the exact wellbore skin value from PTA (s: -4.3), result in a lower value of dimensionless time (2.76×10^3), indicating that the well was still producing from the fracture system which is not true. Fig. 5 indicates that the pressure transient has reached the total system pseudo-steady state in approximately 27 days and the PDA was performed in 227 days. In addition, a negative near zero skin assumption was adopted due to the fact that skin factor is likely to change over time (Khamal). It is usually a tuning parameter in numerical simulation; hence would be a valid assumption (Clarkson).

As is it already known, DMB is an iterative method to estimate the OGIP. The starting point for the iterative process is Eq. 13, in which an initial estimate of GOIP is required. An initial value for the iterative procedure could be G_V: 5.5 Bscf, corresponding to a P50 value of total structure (Table 1). A general flowchart of the process is presented in Fig. 7. Next, the average reservoir pressure and its corresponding fluid properties can be estimated. A plot of $\frac{q_g}{\left(m(P_i)-m(P_{wf})\right)}$ vs. $G\frac{\left(m(P_i)-m(\overline{P})\right)}{\left(m(P_i)-m(P_{wf})\right)}$ will help to confirm the value of OGIP without water influx correction (G), as can be seen in Fig. 8.

Next, the calculated average reservoir pressures were used to calculate the water influx (We). For this example, a finite aquifer model was selected (Fetkovich) to calculate water influx at each time. Finally, corrected values of P/Z, denominated (P/Z**), can be calculated through Eq. 14. The Z factor used was the two-phase values obtained from the PVT analysis and condensate equivalent was considered to calculate the total gas flow rate and total cumulative gas.

A plot of $\frac{q_g}{\left(m(P_i)-m(P_{wf})\right)}$ vs. $\left(\frac{G^{**}}{G}\right)G\frac{\left(m(P_i)-m(\overline{P})\right)}{\left(m(P_i)-m(P_{wf})\right)}$, would help to determine the corrected OGIP (G**: 3.92 Bscf), as can be seen in Fig. 8. Additionally, a P/Z and P/Z** plot can be constructed from the data obtained (Fig. 9).

Discussion:

An extension of Dynamic Material Balance method for volumetric naturally fractured reservoir was proposed, assuming a pseudo-steady state interporosity flow and a closed reservoir. It considered a constant storativity ratio providing two possible results depending on dimensionless time, storativity ratio and interporosity coefficient. Both solutions present a similar format compared with homogeneous solution.

In the first case, the bottomhole flowing pressures were influenced only by fracture system. Consequently, caution must be taken in reporting the OGIP obtained as a total reservoir volume. For the second case, bottomhole flowing pressures was influenced by the total reservoir system (matrix + fractures). Consequently, for this approach the average pressure will represent the fracture system average pressure or the total system average reservoir pressure, respectively.

The field case study presents an example of the total system behavior. The dimensionless time (tDf), was calculated assuming a near zero skin (s: -0.5). Permeability and skin obtained from PTA are more accurate than PDA estimation. PTA correspond to a specific time in well lifetime, nevertheless PDA would give an average value of permeability and skin factor of all drainage area of a longer production time.

The OGIP calculated through the iterative DMB process for NFR, was corrected by water influx (G**: 3.92 Bscf). The Moghadam et. al method was selected for the versatility to obtain a corrected value graphically. This result is in the same order of greatness compared with Monte Carlo estimation (2.9 – 9.2 Bscf).

In November 2013, conventional material balance (Fig. 10) was updated after well 1 and 2 have stopped production due to high water-gas ratio (around 500 bbl/MMscf). The calculated OGIP was 4.23 Bscf considering a Carter-Tracy radial aquifer model. The cumulative production was 2.7 Bscf with a recovery factor of 63.8%, consistent with typical values of water drive mechanism in gas reservoirs. The result was decisive in the development strategy of the field, avoiding the decision of an infill well.

From the authors' point of view, DMB is an excellent alternative to determine the OGIP of gas-condensate in NFR with water influx, especially in absence of measured reservoir pressure.

Conclusions:

The paper discusses the applicability of Dynamic Material Balance in Naturally Fractured Reservoirs with water influx. The main conclusions are as follows:

- Dynamic Material Balance was successfully applied to a gas-condensate naturally fractured. The proposed extension of this method for dual porosity system was validated with the field case study.

- The estimated Original Gas-in-place might represent the fracture system volume or the total system volume depending on the cumulative time of the production data and reservoir heterogeneity. Additional care must be taken to verify this condition to avoid underestimation of OGIP.
- A practical methodology to correct the estimation of Original-Gas-in-Place due to water influx was described for the field case study. Results were coherent volumetric and material balance estimation.

In a future work, we would like to continue to explore the solutions for transient interporosity flow in Dynamic Material Balance.

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NOMENCLATURE

α	Shape factor of the model
β_g	Gas volumetric factor (cf/scf)
β_o	Oil volumetric factor (bbl/STB)
β_w	Water volumetric factor (bbl/STB)
ϕ	Effective Porosity
ϕ_f	Fracture Porosity
ϕ_m	Matrix Porosity
ω	Storativity Ratio
λ	Interporosity flow coefficient
ΔV_{wip}	Change in volume cause by water encroachment, (bbl)
μ_g	Average Gas Viscosity (cp)
μ_o	Oil Viscosity (cp)
b_{pss}	Inverse productivity index (psi²/cp / scf/day)
$\tilde{b}_{pss}$	Inverse NFR productivity index (psi²/cp / scf/day)
A	Area of the reservoir (ft²)
CVD	Constant Volume Depletion
C_A	Dimensionless pseudo-steady state shape factor
c_t	Total compressibility (psi-1)

c_g	Gas compressibility (psi-1)
c_p	Effective pore compressibility (psi-1)
c_{tf}	Total Fracture Compressibility (psi-1)
c_{tm}	Total Matrix Compressibility (psi-1)
C_{wip}	Change in relative volume caused by water influx and water production
DMB	Dynamic Material Balance
G	Total Original-Gas-In-place without correction by water influx (Bscf)
ωG	Original-Gas-In-place of the fracture system without correction by water influx (Bscf)
G^{**}	Corrected Original-Gas-In-place by Water Influx (Bscf)
G_p	Cumulative produced gas
G_V	Original-Gas-In-place from Volumetric Method (Bscf)
h	Net thickness (ft)
k	Effective permeability of the gas (md)
k_f	Fracture permeability (md)
k_m	Matrix permeability (md)
$m(P_i)$	Initial Pseudo- Pressure (psi²/cp)
$m(P_{wf})$	Bottomhole flowing Pseudo-Pressure (psi²/cp)
$m(\overline{P})$	Average Pseudo- Pressure of Total system (psi²/cp)
N	Number of data points
NFR	Naturally Fractured Reservoirs
OGIP	Original-Gas-In-place (Bscf)
P_i	Initial Pressure (psia)
$\overline{P}$	Average Pressure of Total system (psi)
P_{sc}	Standard condition Pressure (14.65 psia)
P_{wf}	Bottomhole flowing pressure (psia)
P_{wD}	Dimensionless pressure at the wellbore
P_{fwD}	Fracture dimensionless pressure
PDA	Production Data Analysis
PPS	Pseudosteady State
PTA	Pressure Transient Analysis
q	Oil rate (STB/d)
qg	Total Gas Rate (Including Condensate Equivalent) (MMscf/d)
QN	Normalized cumulative production
r_e	Reservoir drainage radio (ft)
r_{eD}	Dimensionless radius
r_w	Wellbore radius (ft)
r_{wa}	Effective wellbore radius (ft)

S_{gi}	Initial gas saturation
s	Wellbore skin
t	Time (day)
t_{ca}	Normalized material balance Pseudo-time
t_D	Dimensionless time
t_{AD}	Dimensionless time based on area
t_{Df}	Dimensionless time for dual porosity system
t_s	Stabilization time (hr)
T	Reservoir Temperature (°R)
Tsc	Standard Condition Temperature (520 °R)
We	Water encroachment volume (bbl)
Wp	Cumulative water produced (STB)
Z	Compressibility factor
Z^{**}	Corrected compressibility factor by Water Influx
$Z\ tp$	Two-phase compressibility factor

Sub-index

i	Initial
j	Number of data point of each iteration
k	Number of OGIP value for each iteration

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APPENDICES

Appendix A: Dimensionless variables definition (Da Prat):

$$P_{w_D} = \frac{39.763\times10^{-6}\, kh}{q\,\mu}(P_i - P_f) \qquad \text{(A-1)}$$

$$t_D = \frac{0.00633 k_f t}{\phi c_t \mu\, r_w{}^2}\,. \qquad \text{(A-2)}$$

$$P_{fw_D} = \frac{39.763\times10^{-6}\, k_f h}{q\,\mu}(P_i - P_f) \qquad \text{(A-3)}$$

$$t_{D_f} = \frac{0.00633 k_f\, t}{[(\emptyset C)_f + (\emptyset C)_m]\mu\, r_{w_a}{}^2} \qquad \text{(A-4)}$$

$$r_{e_D} = \frac{r_e}{r_w} \qquad \text{(A-7)}$$

$$t_{AD} = t_D \frac{r_{wa}}{A} \qquad \text{(A-8)}$$

Appendix B: Development of Dynamic Material Balance for Naturally Fractured Reservoirs (Pseudo-steady state matrix flow and closed reservoir).

The dimensionless solution of diffusivity equation for NFR at constant rate for the case of matrix pseudo-steady state flow regime and close reservoir, including wellbore skin, is given by (Da Prat):

For fracture system: $0.1 \le t_{D_f} \le \frac{\omega(1-\omega)}{\lambda}$

$$P_{fw_D} = \frac{2\pi\, t_{AD}}{\omega} + \frac{1}{2} ln\left(\frac{2.2458\, A}{C_A\, r_w{}^2}\right) + s \qquad \text{(B-1)}$$

For total system: $t_{D_f} \ge \frac{\omega(1-\omega)}{\lambda}$

$$P_{fw_D} = 2\pi\, t_{AD} + \frac{1}{2} ln\left(\frac{2.2458\, A}{C_A\, r_w{}^2}\right) + s + \frac{2(1-\omega)^2}{\lambda\, r_{eD}{}^2} \qquad \text{(B-2)}$$

Where:

$$\omega = \frac{\phi_f c_f}{\phi_m c_m + \phi_f c_f} \qquad \text{(B-3)}$$

$$\lambda = \alpha \frac{r_w^2 k_m}{k_f} \tag{B-4}$$

Using de dimensionless definition for dual porosity model, effective radius definition and considering a circular reservoir, Eq. B-1 and B-2 could be written for oil reservoirs as:

For fracture system:

$$P_i - P_{wf} = \frac{141.2\, q\beta_o\mu_o}{k_f\, h}\left[\frac{0.00052748\, k_f\, t}{[(\phi c_t)_f + (\phi c_t)_m]\omega\mu_o\, r_e^2} + ln\left(\frac{r_e}{r_{wa}}\right) - \frac{3}{4}\right] \tag{B-5}$$

For total system:

$$P_i - P_{wf} = \frac{141.2\, q\beta_o\mu_o}{k_f\, h}\left[\frac{0.00052748\, k_f\, t}{[(\phi c_t)_f + (\phi c_t)_m]\mu_o\, r_e^2} + ln\left(\frac{r_e}{r_{wa}}\right) - \frac{3}{4} + \frac{2(1-\omega)^2 r_{wa}^2}{\lambda\, r_e^2}\right] \tag{B-6}$$

Where:

$$r_{w_a} = r_w e^{-s} \tag{B-7}$$

For gas wells, it is applied the definition of pseudo-pressure to account variations in gas properties:

For fracture system:

$$m(P_i) - m(P_{wf}) = \frac{1.422\times10^6\, q_g T}{k_f\, h}\left[\frac{0.00052748\, k_f\, t}{[(\phi c_t)_f + (\phi c_t)_m]\omega\mu_{g_i}\, r_e^2} + ln\left(\frac{r_e}{r_{wa}}\right) - \frac{3}{4}\right] \tag{B-8}$$

For total system:

$$m(P_i) - m(P_{wf}) = \frac{1.422\times10^6\, q_g T}{k_f\, h}\left[\frac{0.00052748\, k_f\, t}{[(\phi c_t)_f + (\phi c_t)_m]\mu_{g_i}\, r_e^2} + ln\left(\frac{r_e}{r_{wa}}\right) - \frac{3}{4} + \frac{2(1-\omega)^2 r_{wa}^2}{\lambda\, r_e^2}\right] \tag{B-9}$$

Where:

$$m(P) = 2\int \frac{P}{\mu Z}dp \tag{B-10}$$

According to Warren and Root (1963) definition of matrix and fracture compressibility, they can be approximated to the gas compressibility for being greater compared with the other terms of the equation (for normally pressured reservoirs):

$$c_{tm} = c_g + \frac{c_p + S_{w_c} c_w + S_o c_o}{1 - S_w - S_o} \cong c_g \tag{B-11}$$

$$c_{tf} = c_g S_g + c_o S_o \approx c_g \tag{B-12}$$

Next a similar procedure presented by Mattar and Anderson can be applied to Eqs. B-8 and B-9. They considered a volumetric gas reservoir and used definition of normalized material balance pseudo-time for variable flow rates:

For fracture svstem:

$$m(P_i) - m(P_{wf}) = \frac{2\, P_i q_g t_a}{\left(\mu_{g_i} c_{g_i}\right) Z_i\, \omega G} + \frac{1.422\times10^6\, q_g T}{k_f\, h}\left[ln\left(\frac{r_e}{r_{wa}}\right) - \frac{3}{4}\right] \tag{B-13}$$

For total system:

$$m(P_i) - m(P_{wf}) = \frac{2\,P_i q_g t_a}{\left(\mu_{g_i} c_{g_i}\right) Z_i\, G} + \frac{1.422\times10^6\; q_g T}{k_f\, h}\left[ln\left(\frac{r_e}{r_{wa}}\right) - \frac{3}{4} + \frac{2(1-\omega)^2 {r_{wa}}^2}{\lambda\, {r_e}^2}\right] \quad \text{(B-14)}$$

Where:

$$\frac{P}{Z} = \frac{P_i}{Z_i}\left(1 - \frac{Gp}{G}\right) \quad \text{(B-15)}$$

$$t_a = \frac{\left(\mu_{g_i} C_{g_i}\right)}{q_g}\frac{Z_i G}{2P_i}\left(m(P_i) - m(\overline{P})\right) \quad \text{(B-16)}$$

$$G = \frac{(\phi_f + \phi_m)\, A h P_i T_{sc}}{Z P_{sc} T} \quad \text{(B-17)}$$

$$C_{t_i} \cong C_{g_i} \quad \text{(B-18)}$$

Eqs. B-13 and B-14 can be simplified by defining b_{pss} and $\tilde{b}_{pss}$:

For fracture system:

$$\frac{m(P_i) - m(P_{wf})}{q_g} = \frac{2\,P_i}{\mu_{g_i} C_{g_i} Z_i}\frac{t_a}{\omega G} + b_{pss} \quad \text{(B-19)}$$

For total system:

$$\frac{m(P_i) - m(P_{wf})}{q_g} = \frac{2\,P_i}{\mu_{g_i} C_{g_i} Z_i}\frac{t_a}{G} + \tilde{b}_{pss} \quad \text{(B-20)}$$

Where:

$$b_{pss} = \frac{1.422\times10^6\; T}{k_f\, h}\left[ln\left(\frac{r_e}{r_{wa}}\right) - \frac{3}{4}\right] \quad \text{(B-21)}$$

$$\tilde{b}_{pss} = \frac{1.422\times10^6\; T}{k_f\, h}\left[ln\left(\frac{r_e}{r_{wa}}\right) - \frac{3}{4} + \frac{2(1-\omega)^2 {r_{wa}}^2}{\lambda\, {r_e}^2}\right] \quad \text{(B-22)}$$

Rearranging terms and expressing Eqs. B-19 and B-20 as a straight line, the final form would be:

For fracture system:

$$\frac{q}{m(P_i) - m(P_{wf})} = -\frac{1}{b_{pss}(\omega G)}\frac{G\left(m(P_i) - m(\overline{P})\right)}{\left(m(P_i) - m(P_{wf})\right)} + \frac{1}{b_{pss}} \quad \text{(B-23)}$$

For total system:

$$\frac{q}{m(P_i) - m(P_{wf})} = -\frac{1}{\tilde{b}_{pss}\,(G)}\frac{G\left(m(P_i) - m(\overline{P})\right)}{\left(m(P_i) - m(P_{wf})\right)} + \frac{1}{\tilde{b}_{pss}} \quad \text{(B-24)}$$

Appendix C: Tables

Probability Results		Percentiles		
		P90	P50	P10
Original Gas In-Situ	[BCF]	2.9	5.5	9.2
Gas Separator	**[BCF]**	**1.6**	**3.1**	**5.3**
Recovery Factor	[fracción]	0.532	0.573	0.614
Gas Reserve	**[BCF]**	**1.5**	**2.8**	**4.7**
Rock Volume	[MM m3]	13.42	18.99	23.48
Net/Gross	[fracción]	0.62	0.74	0.88
Porosity	[fracción]	0.06	0.08	0.11
Water Saturation	[fracción]	0.25	0.39	0.60

Table 1. Volumetric estimation using Monte Carlo method. Total structure (West + East).

Datos del Reservorio:		
Pi:	5890	[psia]
Tr:	247	[deg F]
Ø prom:	0.086	[fracción]
Sw prom:	0.478	[fracción]
SGg:	0.965	
CGR:	120	[STB/MMscf]

Aquifer data:		
Model:	Fetkovich	
Reservoir thickness [h]	200	ft
Reservoir radio [re]:	2190	ft
Out/In Ratio:	18	
Encroachment angle:	170	deg
Aquifer perm. [k]:	0.9	md

Table 2. Reservoir and Aquifer general information.

Appendix D: Figures

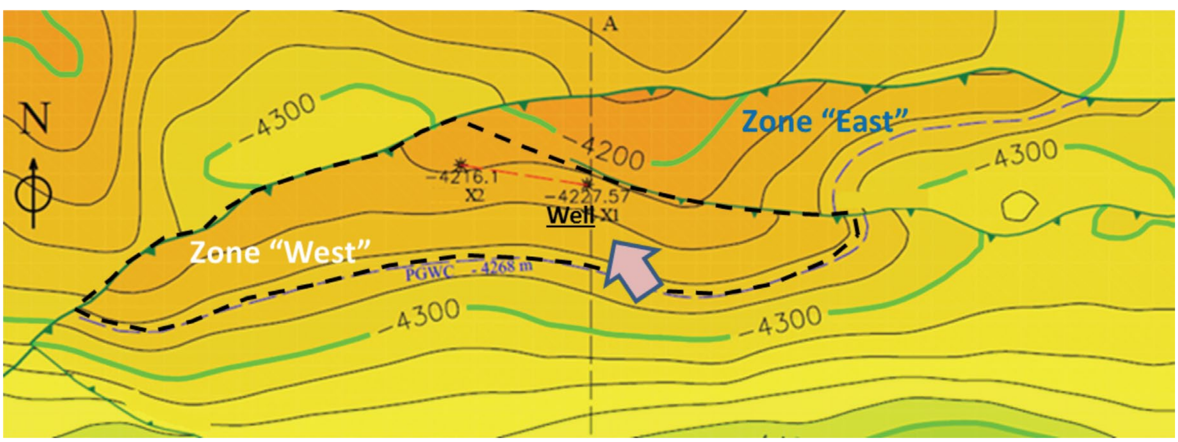

Figure 1. Structural map of the Field under study, considering both regions (West and East).

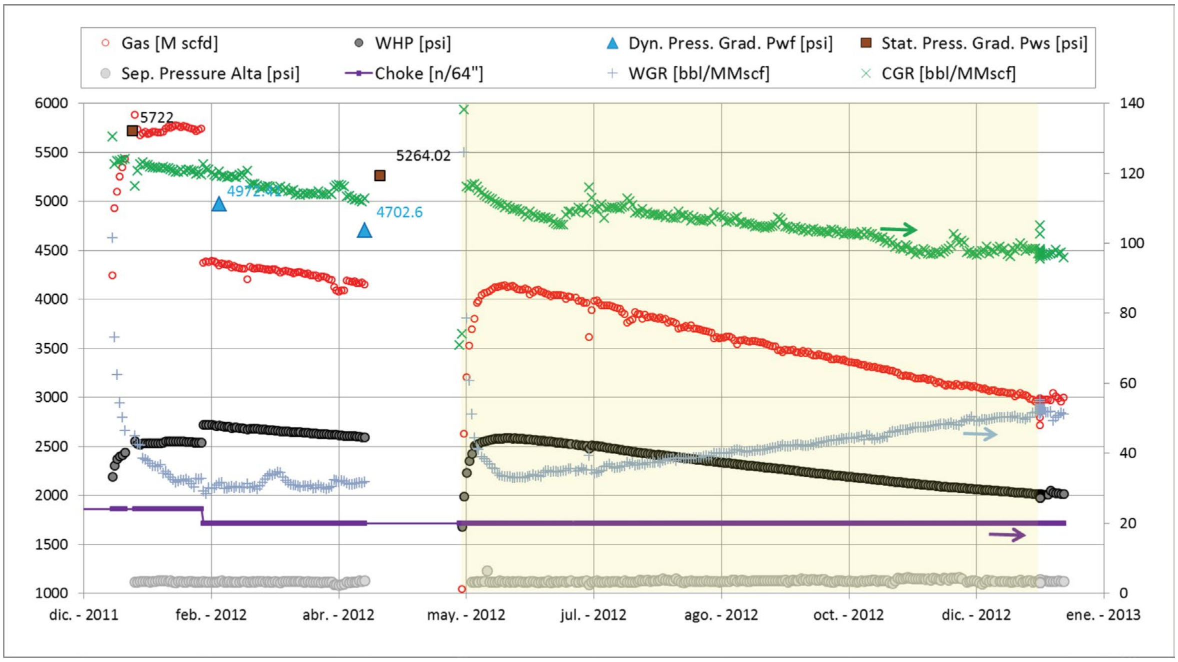

Figure 2. Complete production and pressure history. Well 1.

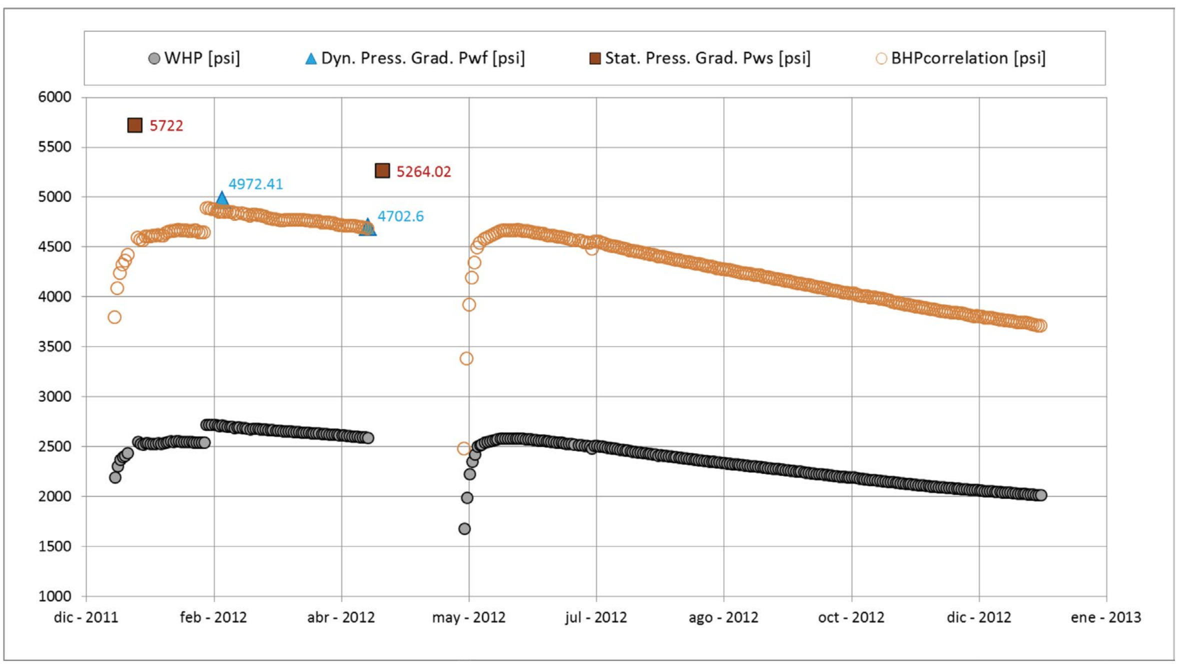

Figure 3. Bottomhole flowing pressure calculated and compared with measured data. Well 1.

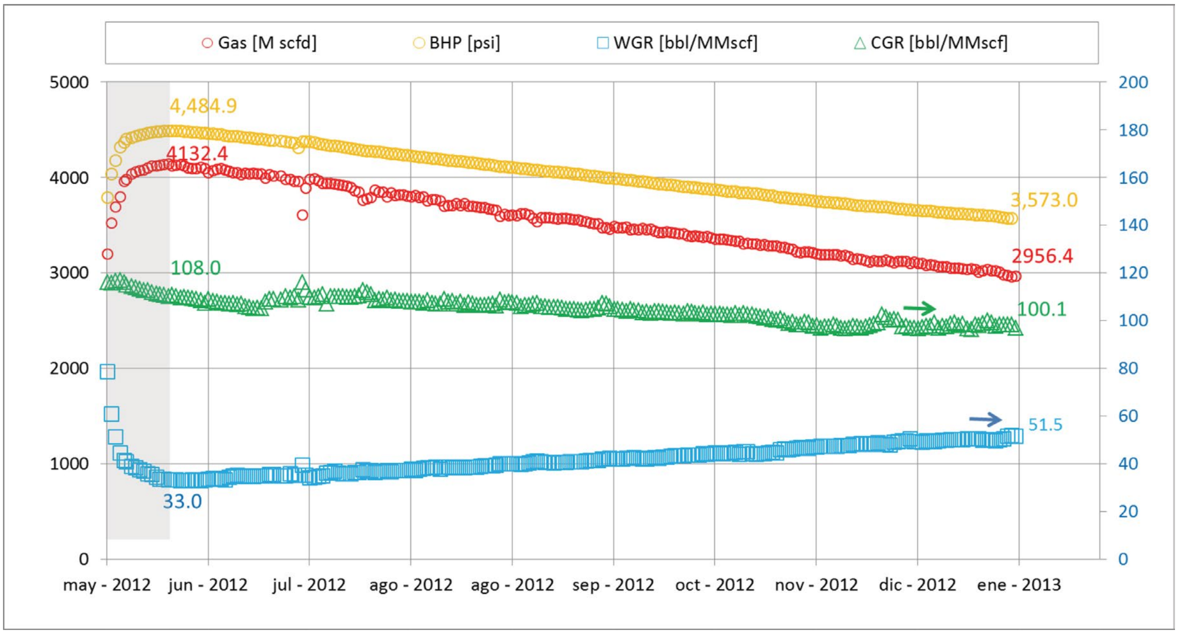

Figure 4. Selected production data from Well 1.

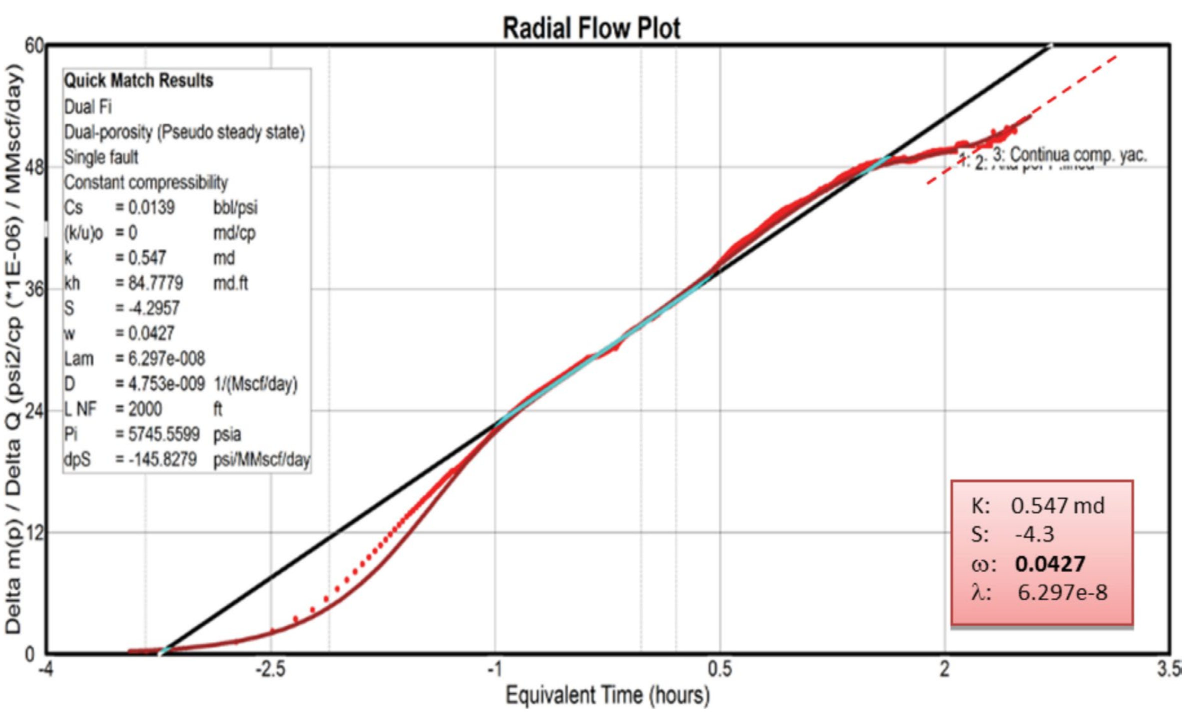

Figure 5. Pressure transient analysis of the first drawdown (dual porosity model and PPS). Well 1.

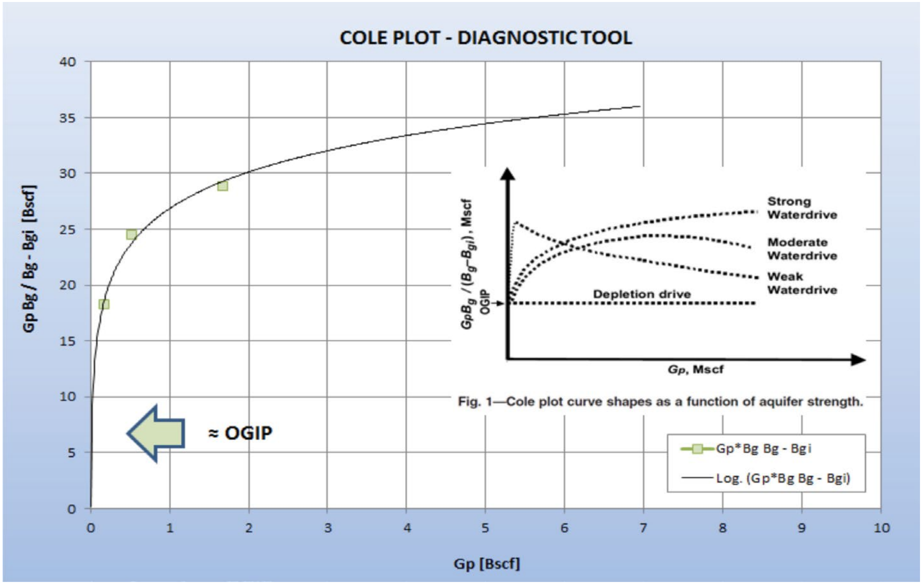

Figure 6. Cole Diagnostic plot to determine water influx strength. Well 1.

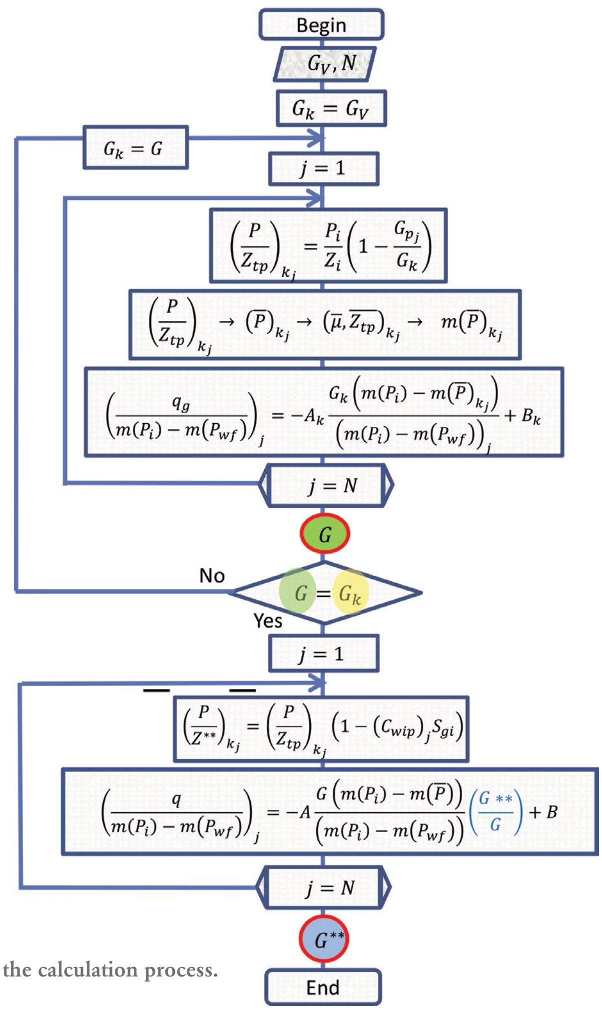

Figure 7. Flowchart of the calculation process.

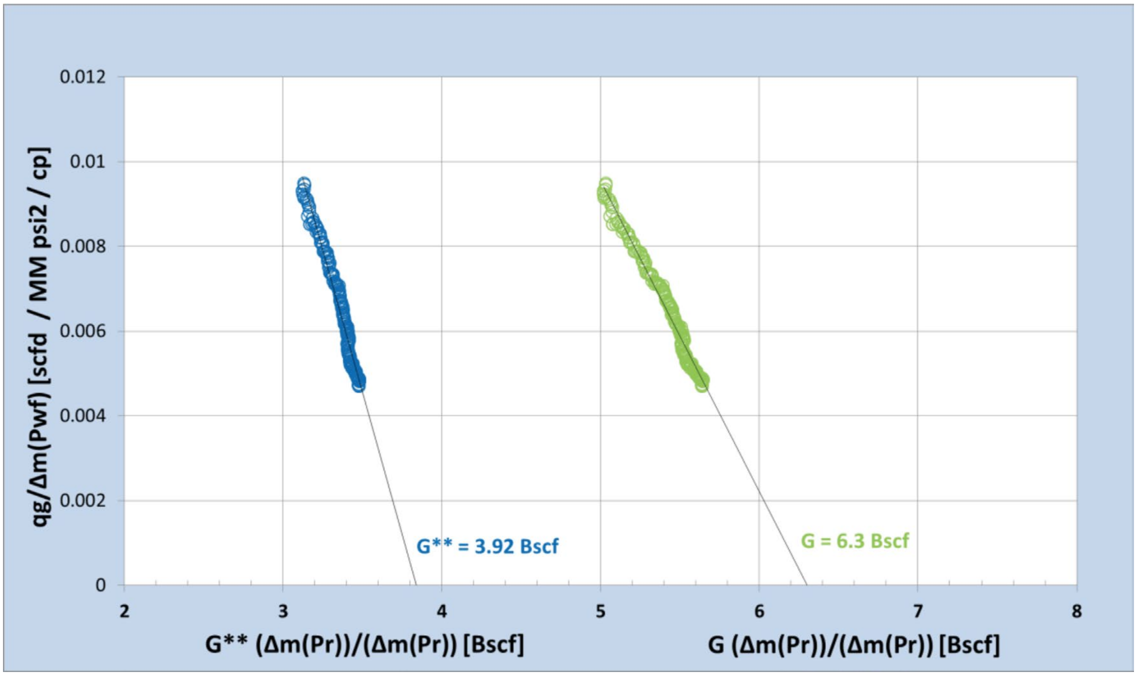

Figure 8. Dynamic material Balance plot to determine the Corrected Gas-in-Place (G**).

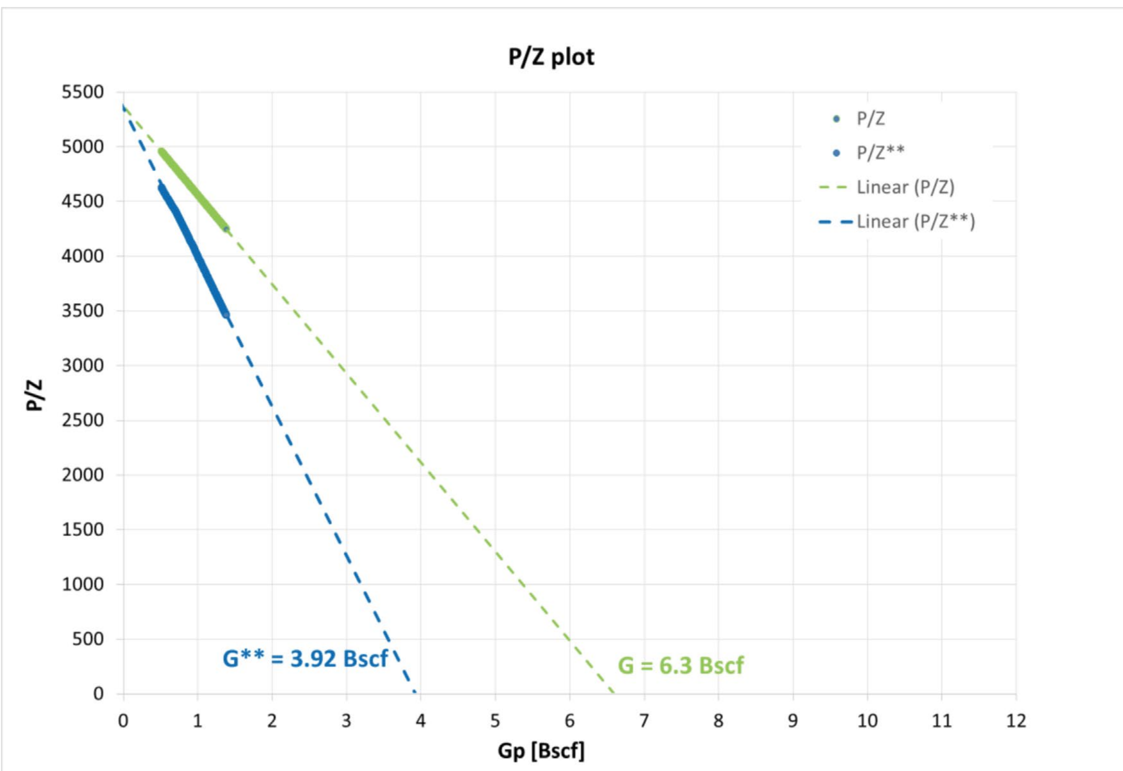

Figure 9. Calculated P/Z and P/Z** Plot of the Field Case Study.

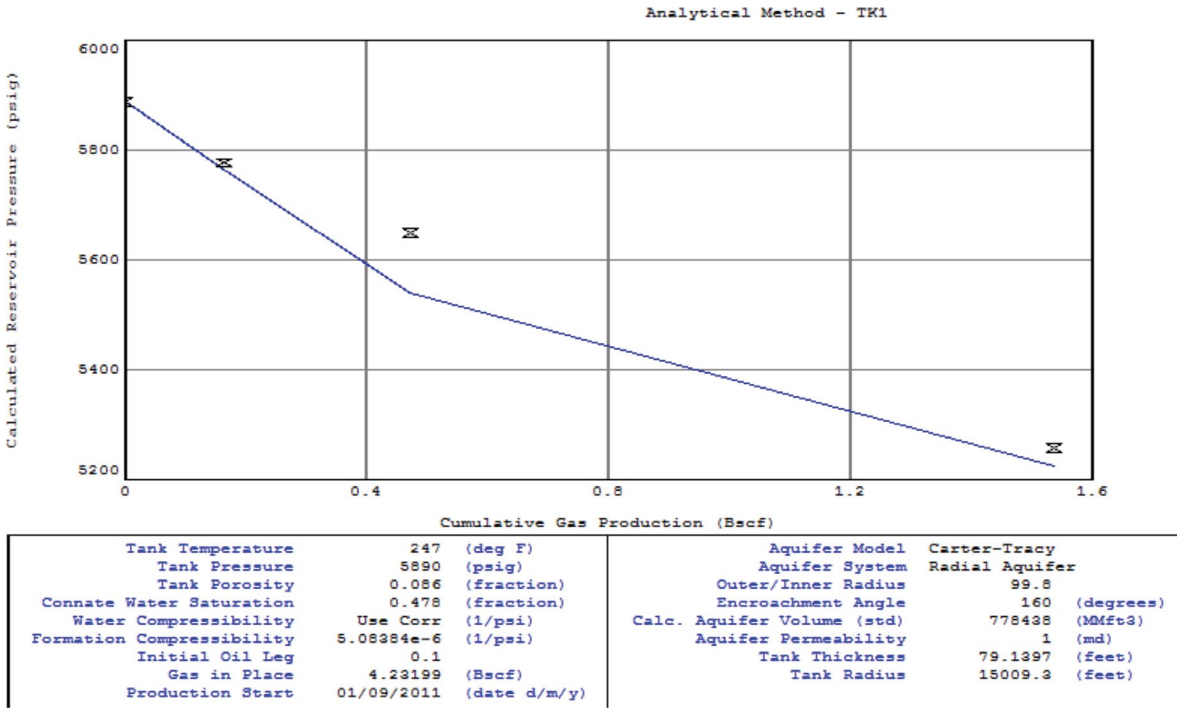

Figure 10. Conventional P/Z plot of the Field Case Study.

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