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RESEARCH PAPER

Comprehensive Studies on Production Data Analysis of Hydrocarbon Reservoirs

Mohammad Hosein Zareenejad [a,*], Azim Kalantariasl[b]

a. Department of Petroleum Engineering, Marvdasht Branch, Islamic Azad University, Marvdasht, Iran
b. Department of Petroleum Engineering, School of Chemical and Petroleum Engineering, Shiraz University, Shiraz, Iran

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Abstract

A review of field production data reveals that usually, it is very difficult to apply available decline models because of poor quality and often noisy character of initial data and also unrealistic assumptions of the models. This paper tries to introduce applicable procedures to correct initial data and reproduce missed data. Corrected data are analyzed and finally, the results for permeability and skin factor estimations are compared to results of transient well test analysis. Estimations for Initial Hydrocarbon In Place (IHIP) and reserve are also compared to the results of Material Balance Equation (MBE) and static model through field case studies. It is proved that the analysis can present acceptable estimations for radial permeability and skin values in naturally fractured reservoirs (NFR). Flowing material balance and Buba and Blasingame plotting function model give the best estimations for Original Gas In Place (OGIP) and gas reserve respectively. A simple but useful and applicable method is presented to determine reservoir fracture distribution mapping. It is also showed that the analysis can be used to distinguish water influx successfully.

Keywords:
Decline Curve Analysis,
Fracture Distribution,
History Matching,
Permeability,
Skin Factor

Introduction

In a simple definition decline curve analysis (DCA) is the study of the downswing of the past productive trend with the use of production rate-time and rate-cumulative production data for a well or a reservoir [1]. Using DCA and estimation of initial Hydrocarbon In Place (IHIP) and reserve, reservoir permeability and skin factor can be determined.

The use of production data as a forecasting tool backs to the early works of Arnold and Anderson, Lewis and Beal, and also Arps. [2,3]. In 1940s Arps tried to use a group of empirical hyperbolic equations to model real production data [4,5]. In the early 1970s, Fetkovich proposed a substantial improvement in DCA by suggesting the matching production data with specialized type curves [6,7]. Doublet et al. [8] reported the limitations of the Fetkovich model which are largely due to non-compatibility with field operations and reservoir inconsistencies that distort the production data in particular common in practice, the variable rate/pressure histories. Another issue is the oversimplification of the gas flow solution since for large drawdown cases the liquid case cannot be used to represent the gas flow case [9].

Da Prat and Hebert [10] found the production behavior of infinite and finite acting naturally fractured oil reservoirs for Warren and Root model and developed type curves for the reservoirs producing at constant bottom-hole pressure.

* Corresponding author:
Email: mh.zareenejad86@miau.ac.ir (M. H. Zareenejad)

Later Palacio and Blasingame proposed a rigorous approach for the analysis of variable rate and variable bottom-hole pressure data using a superposition time function called material balance time. It also accounts for the variation in producing fluid changes during production [11,12]. Agarwal et al. [7] demonstrated that using the function converts the constant pressure solution into the constant rate solution which is widely used in well testing. Using the equivalence of the solutions; they developed a fully analytical new set of type curves similar to Fetkovich. Mattar and Anderson [13] later introduced the flowing material balance model which uses the concept of the normalized rate and normalized material balance pseudotime to create a simple linear plot, which extrapolates to fluids in place.

Buba and Blasingame [1] extended previous studies on semi-analytical direct rate-cumulative production models for determining average reservoir pressure, future rate and cumulative production for gas wells producing at constant bottom-hole pressure during reservoir depletion and proposed a linear plotting function model which extrapolates to gas reserve using only time and flow rate data.

Zareenejad et al. [14] tried to use the most important DCA models to evaluate permeability in some Iranian reservoirs. Later they tried to estimate reservoir parameters in the drainage area of horizontal wells using available vertical models [15]. They also applied conventional decline models to estimate Original Gas In Place (OGIP) and Expected Ultimate Recovery (EUR) in a gas condensate reservoir [16].

Aljehani et al. [17] presented a numerical procedure for flow simulation and estimation of relative permeability of naturally fractured carbonate rocks by history matching laboratory-derived multi-phase production data. They validated the procedure by comparing it with the laboratory obtained production data. Artus and Houzé [18] used DCA to reproduce the response of an SRV-bounded analytical model in unconventional reservoirs. They used a decline curve matching to infer three relationships between the physical model parameters consisting of the number of fractures, half-length, completion length, and permeability successfully.

Zhang et al. [19] used Markov Chain Monte Carlo, artificial intelligence, and machine learning algorithms to improve history matching and to obtain more accurate probabilistic production forecasting using actual decline production data. Masini et al. [20] used Cutting-edge clustering techniques to identify the data points where the decline curve is applicable. They showed the ability of the algorithms to perform the DCA automatically.

A review of field production data reveals that usually, it is impossible to apply available DCA models because of poor quality and often noisy character of initial production data and also unrealistic assumptions of the models for initial input data which makes DCA become one of the most neglected reservoir engineering techniques. This paper introduces applicable procedures to correct the initial data and produce missed data that is useful, applicable, and necessary. Finally, the results of permeability and skin factor estimations will be compared to transient well test analysis results through field case studies. Estimations for IHIP and reserve will also be compared to the results of Material Balance Equation (MBE) and static model in order to demonstrate the value of DCA and proposed correction procedures. A simple but useful and applicable method is also presented to determine reservoir fracture distribution mapping based on only DCA estimations for permeability and drainage area.

Production Data Limitations and Recommendations for Correction

A Continuous Decline Period in Production History of Wells/Reservoirs Is Not Available

All the models assume a continuous decline period with time, while real field data exhibit only some scattered decline periods even when a decline in the reservoir boundaries has been reached. Hence a stepwise procedure is recommended:

- Initial screening of production data
- Selection of decline periods
- Identification and elimination of errors and/or anomalies
- Time re-initialization of data

Modification of Initial Reservoir Pressure

After data correction, initial reservoir pressure must be corrected which depends on the type of the reservoir:

Oil Reservoirs

Following steps must be done:

- Combining the material balance equation and oil flow equation:

$$\frac{q}{\Delta p} = \frac{1}{b_{pss}} - \frac{1}{Nc_t b_{pss}} \frac{N_p}{\Delta p} \tag{1}$$

Where Δp and b_{pss} are obtained from the following equations:

$$\Delta p = (p_i - p_{wf}) \tag{2}$$

$$b_{pss} = \frac{141.2 B_o \mu_o}{kh} \frac{1}{2} Ln(\frac{4}{e^A} \frac{A}{C_A r_{wa}^2}) \tag{3}$$

- Plot of $q/\Delta p$ vs. $N_p/\Delta P$ will yield a straight line with y-intercept as $1/b_{pss}$
- Calculating average reservoir pressure which must be used instead of initial reservoir pressure from Dake's oil flow equation [21]:

$$\bar{p} = p_{wf} + q b_{pss} \tag{4}$$

Gas Reservoirs

It was seen that there is an approximate linear functional relation between reservoir pressure and time. "Least square interpolation technique" must be used to determine the function and reservoir pressure at the beginning of selected data instead of initial pressure.

Bottom-Hole Flowing Pressure Data Are Not Recorded Regularly

Determination of Bottom-Hole Flowing Pressure Versus Time

Bottom-hole flowing pressure (BHFP) data are not recorded regularly, but usually, it is seen that average reservoir pressure data (estimated by transient buildup tests) exhibits an approximate linear decline with time. Considering the average reservoir pressure trend, it is recommended to define a linear function of BHFP with time for each well using available recorded data. It must be noted that the linear function seems much more valid in naturally fractured reservoirs (NFR) due to the high transmissibility of extended fracture networks and if BHFP data are not available for some wells it is recommended to assume uniform pressure decline rate throughout the entire reservoir.

Defining a Constant Single Value for BHFP

Some models assume constant BHFP during production, however, for volumetric reservoir producing for long times the assumption is interrupted. It is recommended to calculate and use an average value for BHFP corresponding to the selected data for the models.

Determination of BHFP using Wellhead Flowing Pressure

Usually, wellhead flowing pressure is recorded instead of BHFP. It is recommended to convert surface data to BHFP data considering well geometry using pressure drop correlations that depends on the type of producing fluid:

- Single-phase flow of gas or oil: pressure drop must be calculated using the Hagen-Poiseuille equation as follows [22]:

$$\Delta p = \frac{128\mu LQ}{\pi d^4} \tag{5}$$

- Two-phase flow: mathematical modeling of two-phase flow is extremely complex so empirical correlations and/or gradient curves must be used.
  Pressure drop correlations: it is proved that Beggs & Brill correlation which takes into account different flow regimes and uses general parameters as functions of inclination degree gives the best results [23].
  Gradient curves: when estimations are needed and circumstances do not let time-consuming correlations a common approach is to use gradient curves. The only limitation is to find a graph corresponding to the given conditions [24].

Exclusive Models for Gas Condensate Reservoirs Are Not Developed

Investigations show all the available DCA models implicitly assume the producing fluid in the reservoir at all pressures as well as on the surface is a single phase, while the assumption is interrupted in gas condensate reservoirs. Thus, as long as the reservoir fluid remains in a single (gas) phase, the available models may be used, but if a hydrocarbon liquid phase developed in the reservoir they are not applicable. The following instructions are recommended:

- *Lean gas condensate reservoirs:* it is proved that for reservoirs with Liquid-Gas Ratio (LGR) less than 100 bbl/MMScf the contribution of condensates is insignificant.
- *Reach gas condensate reservoirs:* for reservoirs with LGR, more than 100 bbl/MMScf available models must be treated specially. It is recommended to convert condensate volumes to equivalent gas volume and recombine with gas rate stream. Hence the gas production or equivalently cumulative production-time, G_p-t data must include the separator gas production, the stock tank gas production, and the stock tank liquid production converted to its gas equivalent, symbol *GE*. Using frequent three- and two-stage separation systems the G_p data must be corrected as below respectively:

$$G_p=G_{p(surf)}+GE(Np)=G_{ps}+G_{ss}+G_{st}+GE(N_p): \quad \textit{Three-stage separation} \tag{6}$$
$$G_p=G_{p(surf)}+GE(Np)=G_{ps}+G_{st}+GE(N_p): \quad \textit{Two-stage separation} \tag{7}$$

The gas equivalent of one stock tank barrel of condensate liquid is:

$$GE=133000\gamma_o/M_{wo} \tag{8}$$

If water is produced on the surface due to condensation from the gas phase in the reservoir, it must be converted to an equivalent and added to the production as [18]:

$$GE_w = 7390\ SCF/surface\ barrel \tag{9}$$

Exclusive Models for NFRs Are Not Applicable

A naturally fractured reservoir is a heterogeneous system consisting of two distinct systems, matrixes and fractures [25]. Due to the following reasons, data analysis of such reservoirs using available limited fractured models is usually impossible:

- Available models are not applicable in practical conditions and they cannot model real production data with acceptable accuracy. For example, the variations of fluid properties with pressure or changes of BHFP with time have not been considered in any model. Therefore, it can be considered that a perfect and reliable model for NFRs has not been developed yet.
- The production trend of NFRs exhibits two decline rate periods and a constant one between them, while some show the production trend of conventional reservoirs.
- In order to analyze data using fractured models, values of ω and λ which are determined by transient well test analysis must be available, while they are rarely determined [26].

Due to the above limitations, it is recommended to analyze the production data of NFRs using available conventional models. However, Zareenejad et al. determined the permeability of NFRs with an acceptable accuracy using the models but; it is not clear that the values are either for the reservoir matrix or fracture [14].

A synthetic cylindrical naturally fractured gas reservoir is built using CMG commercial simulator. The model is divided into 30, 12, and 20 grids in r, Θ and z directions respectively. Gas production and corresponding pressure decline in the fracture leads to gas flow from the matrix into the fracture system; the fracture system acts both as a sink to the matrix system and as a conduit to production wells.

PVT and reservoir rock properties of the model were taken from a real southern Iranian reservoir as shown in Fig. 1. Other model rocks and fluid properties are shown in Table 1. The real reservoir has three active producing wells with 0, and +5 skin factors respectively. Transient well testing estimates 19.1, 19.7, and 17.7 *md* for permeability in different wells drainage area respectively.

Table 1. Other rock and fluid properties of the synthetic model

Property	Value	Unit
P_i	8000	psi
$P_{b,initial}$	4640	psi
S_{wc}	0.1	-
K_{matrix} in radial direction	0.206	md
K_{matrix} in vertical direction	0.206	md
$K_{fracture}$ in radial direction	20	md
$K_{fracture}$ in vertical direction	2	md
Ø	11	-
C_f	1.0E-06	psi^{-1}
C_w	3.2E-06	psi^{-1}
C_o	1.4E-05	psi^{-1}
ρ_w	69.58	Ib/ft^3
ρ_o	57.7	Ib/ft^3
P_g	0.06	Ib/ft^3

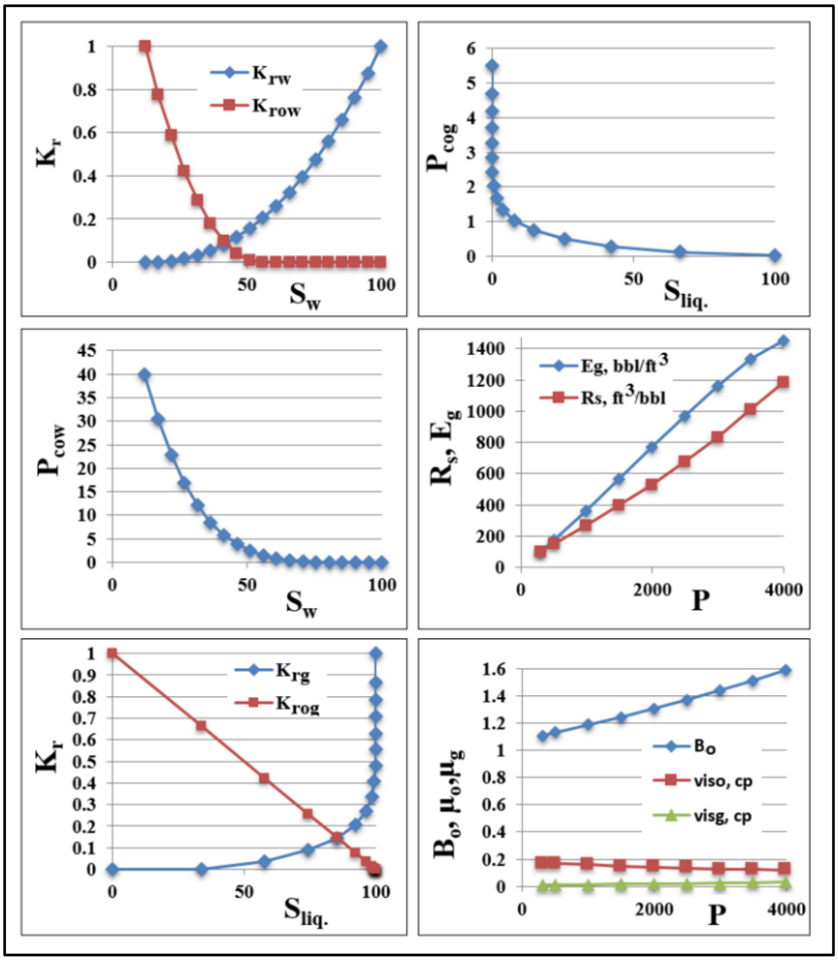


Fig. 1. Real field data used to build the synthetic model

Table 2 shows DCA estimation results for the model production data. Average Absolute Relative Error Percent (ARE) of the DCA permeability estimations in comparison to filed values are 17.74, 9.34, and 4.28 for Fetkovich, Blasingame, and Agarwal-Gardner models respectively. A comparison of DCA permeability with the model matrix and fracture permeability is also shown in Table 3. Clearly, DCA presents acceptable estimations for radial permeability of fracture rather than a matrix. The best ones are that of the Agarwal-Gardner model.

Table 2. DCA permeability estimations for the synthetic model

Well No.	Estimated Permeability, md			Skin Factor		
	Fet. TC	B. TC	A-G TC	Fet. TC	B. TC	A-G TC
01	22.1312	17.039	19.4281	-1.6629	-2.9509	-3.9956
02	27.6285	19.1285	20.1316	-1.5455	-2.8534	-3.9302
03	15.5955	17.2039	18.0162	-1.5005	-0.2790	-1.3818

Table 3. Comparison of DCA permeability estimations with model permeability values

Well No.	Relative Error Percent of Fracture Permeability $\left\lvert\frac{k_{\mathrm{DCA}}-k_{\mathrm{fracture}}}{k_{\mathrm{fracture}}}\right\rvert\times 100$			Relative Error Percent of Matrix Permeability $\left\lvert\frac{k_{\mathrm{DCA}}-k_{\mathrm{matrix}}}{k_{\mathrm{matrix}}}\right\rvert\times 100$		
	Fet. TC	B. TC	A-G TC	Fet. TC	B. TC	A-G TC
1	10.656	14.805	2.859	10643.3	8171.359	9331.117
2	38.142	4.357	0.657	13311.89	9185.679	9672.621
3	22.022	13.98	9.919	7470.631	8251.407	8645.728

Reservoir Fracture Distribution Mapping

As proved before the radial permeability of fracture and drainage area data of individual wells can be estimated. Definitely drainage area of each well limits boundaries in which specific characteristics of a well such as permeability are dominating. Thus, it is possible to determine permeability distribution mapping throughout the reservoir. Since, due to high transmissibility, the drainage area of the individual wells may overlap, the average value of fracture permeability must be calculated throughout overlapped areas. Obviously, radial permeability is representative of fracture networks so the map actually presents fracture distribution mapping.

There Are Poor Quality and Often Noisy Initial Data

Despite applying all previous correction instructions, sometimes corrected data are still noisy and scattered which makes the matching procedure impossible. It is usually due to human errors or truncation errors during records and calculations. It is recommended to use cumulative production-time data instead of rate-time data. Data smoothing techniques can also be taken using MATLAB software which presents a much smoother plot. It is proved that "Lowess linear fit" gives the best results.

Applying Buba and Blasingame Model using Initial Data Is Impossible

While applying Buba and Blasingame plotting function model (PFM) usually it is impossible to extrapolate a linear plot. A stepwise procedure is recommended to reproduce appropriate data:

- Initial screening of production data
- Selection of decline periods
- Identification and elimination of errors and/or anomalies
- Usually, smoothed data are still scattered which makes it impossible to extrapolate the linear trend (q_{gi}-q_g/G_p vs. G_p), which is often due to the noisy character of production data. It is recommended to find the best hyperbolic model which fits smoothed rate-time data and reproduce corrected data.

The steps of preparing appropriate data and linear plot extrapolation of well#11B to apply PFM are shown in Fig. 2 and Fig. 3 respectively.

Other Recommendations

It is also recommended to:

- Calculate average porosity and average water saturation in well drainage area using well petrophysical data
- Calculate well temperature using average values of bottom-hole temperature from reported temperature survey tests

Case Studies

Naturally fractured lean gas condensate reservoir "A": reservoir "A" is a carbonate and PVT tests show almost unchanged fluid composition. Pressure and production trends also prove that there are extended fracture networks throughout the entire reservoir. OGIP is estimated at 26.6 *TSCF* and 124 *acres* for drainage area using MBE. The reservoir LGR is 12 *bbl/MMScf*.

Naturally fractured gas condensate reservoir "B": production started at the rate 333 *MMScf/D* of gas and *2431 STB/D* of condensate. OGIP is estimated at 14.621 *TSCF* and 55 *acres* for drainage area using MBE. No water has been produced and based on the studies aquifer does not affect gas production. Several PVT analyses for different wells indicate unchanged PVT properties with depth, close agreement of pressure measurements in different wells at the same periods are also indicative of good areal communication through the fracture networks all over the entire reservoir. It is proved that in comparison to the northwestern parts, the fracture intensity in central and southeastern parts are higher.

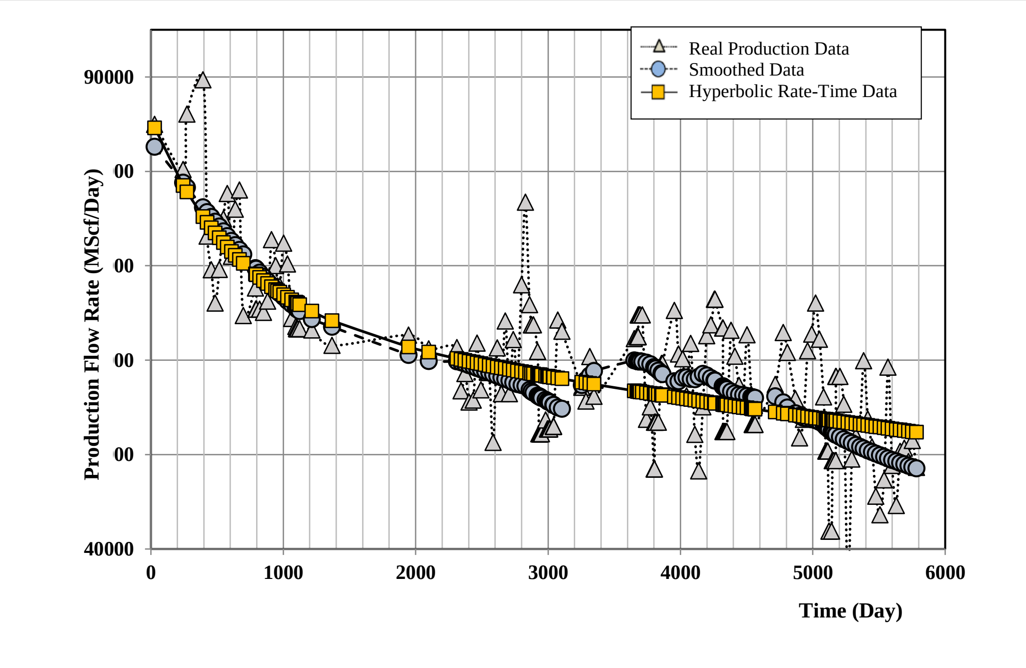


Fig. 2. Preparing appropriate data for well#11B to apply PFM

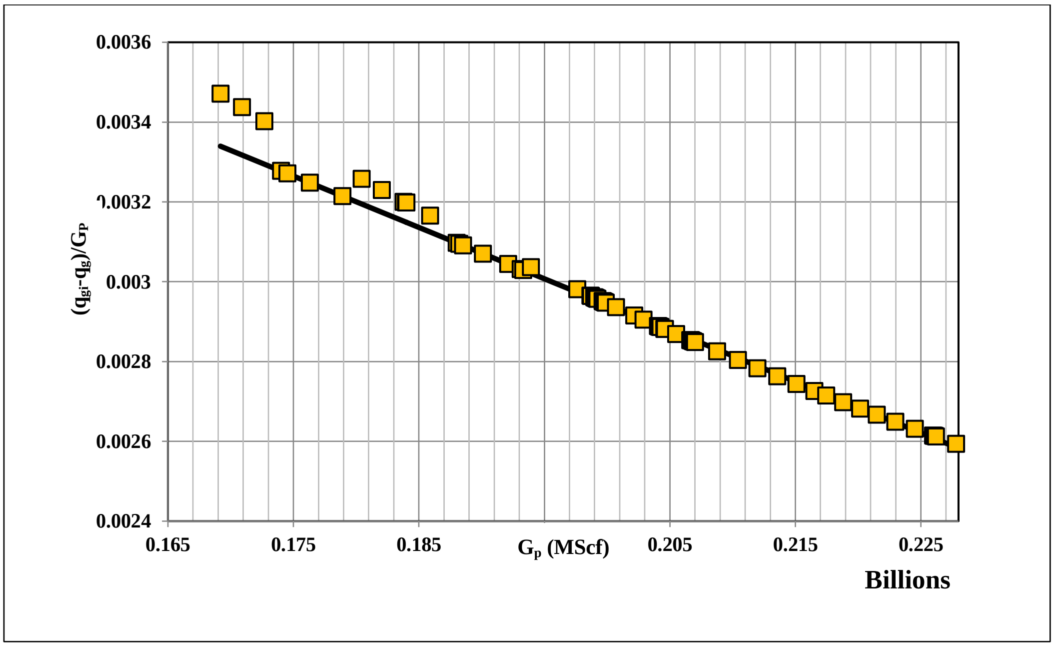


Fig. 3. Linear plot extrapolation for well#11B

Undersaturated tight oil reservoir "C": well test data reveals no major contribution of fracture and the average permeability is very low in N-S elongated anticline "C". It has no initial gas cap and the size and permeability of aquifer are too low to maintain the pressure of the reservoir. The permeability range is 0.1-3 *md*. Three different estimates have been reported for the OOIP. The value of 1340 *MMSTB* has been estimated, while, two different estimates in the range of 1573 and 2072 *MMSTB* were reported also.

Naturally fractured oil reservoir “D”: reservoir rock is mostly carbonate but sandstone parts exist also in the reservoir. OOIP has been estimated 2255 *MMSTB* and there is an active aquifer.

Results and Discussions

The recommended procedures for data preparation were performed respectively for all wells of the four studying reservoirs. Finally, corrected data were imported into the software F.A.S.T RTA and the analysis was performed. Estimated permeability values are shown in Table 4 which is compared with well test results. Results show that Agarwal-Gardner and Blasingame models can present acceptable estimations, and implicitly indicates that the data preparation procedure proposed in the study. ARE values of the models are 12.49 and 14.82 respectively. Unacceptable results of the Fetkovich model is due to its unrealistic basic assumptions which ignore variations of producing fluid properties with pressure and assumption of BHFP constant over the analysis time span.

Table 4. Comparison of DCA permeability estimations in different reservoirs

Well No.	Estimated Permeability, md				Err % $\left\lvert\frac{k_{\text{DCA}}-k_{\text{Well Test}}}{k_{\text{Well Test}}}\right\rvert\times100$		
	Well Test	**Fet. TC**	**B. TC**	**A-G TC**	**Fet. TC**	**B. TC**	**A-G TC**
1A	124	30.686	93.829	102.335	75.253	24.331	17.471
3A	9.75	11.136	11.586	9.048	14.215	18.83	7.2
7A	6	7.869	5.322	5.922	31.15	11.3	1.3
8A	6.5	5.829	5.608	6.464	10.323	13.723	0.553
15A	32.5	40.027	32.511	36.09	23.16	0.033	11.046
1B	15.834	10.755	15.191	14.83	32.075	4.056	6.338
2B	8.6	7.123	7.4651	9.303	17.174	13.196	8.184
3B	27.2	3.328	34.542	29.901	87.763	26.993	9.932
1C	1.87	3.328	1.468	1.571	77.967	21.497	15.989
2C	2.144	2.348	2.223	2.749	9.514	3.684	28.218
3C	1.05	13.059	1.558	0.812	1143.714	48.38	22.666
4C	2.281	4.818	2.308	2.721	111.223	1.183	19.289
5C	1.295	2.113	1.556	1.516	63.166	20.154	17.065
6C	1.84	4.816	1.983	1.748	161.739	7.771	5
7C	2.626	5.846	2.41	2.746	122.62	8.225	4.569
8C	1.887	3.905	2.115	2.352	106.942	12.082	24.642
9C	2.534	3.103	1.942	2.218	22.454	23.362	12.47
10C	2.902	4.089	2.242	3.408	40.902	22.742	17.436
11C	2.243	1.506	2.221	1.95	32.857	0.98	13.062
2D	300.322	374.272	331.222	306.429	24.623	10.288	2.033
2D	300.322	651.074	357.228	360.795	116.792	18.948	20.136
5D	264.862	322.218	226.931	237.367	21.655	14.321	10.38
6D	208.415	281.582	230.355	226.236	106.694	14.822	12.499

A comparison of skin factors is also shown in Table 5. The results are in agreement with those of transient well test analysis. It must be mentioned that the amount of DCA skin factor must be considered qualitatively rather than quantitatively, i.e., the sign- negative or positive- is more important than the value. Negative values can be considered to be affected by existing fracture networks in the vicinity of producing wells and also periodic well stimulations. It must be also noted that it is not so reasonable to compare DCA skin values to those of the well test analysis because well test values show the condition of producing well in a short time span and the values may change with time due to damage or stimulation, while DCA values are results of analyzed data of a long time span. The results in Table 4 and 5 clearly show that DCA allows inexpensive production tests to replace expensive transient tests. It is not required to shut in the producing wells and furthermore wellbore storage effects do not exist.

Table 5. DCA skin factor estimation for the reservoirs

Well	Skin Factor			
No.	**Well Test**	**Fet. TC**	**B. TC**	**A-G TC**
1A	343.236	-2.613	4.966	5.001
3A	1.2	-2.516	-8.024	-8.588
7A	-1.09	-4.743	-8.434	-8.425
8A	-3.5	-2.354	-7.812	-8.35
15A	-0.88	-3.23	-9.058	-9.073
1B	-3.674	-1.837	-1.151	-1.145
2B	-5.35	-4.556	-8.579	-9.129
3B	-4.92	-7.211	-8.045	-8.597
1C	-8.315	-6.987	-8.012	-7.896
2C	-7.827	-7.917	-7.89	-7.58
3C	-6.708	-6.004	-8.345	-7.932
4C	-8.275	-7.368	-8.37	-7.809
5C	-8.529	-6.621	-7.084	-7.051
6C	-8.297	-7.972	-7.023	-7.028
7C	-8.69	-7.49	-8.608	-8.549
8C	-7.152	-6.927	-7.808	-7.722
9C	-8.495	-7.914	-8.511	-8.352
10C	-8.5	-7.537	-8.395	-7.793
11C	-8.3	-7.196	-6.738	-6.829
2D	-5.8	-7.671	-10.118	-9.484
	-4.794	-3.669	-10.55	-10.103
5D	-6.325	-3.313	-10.461	-10.06
6D	208.415	281.582	230.355	226.236

All of the models presume that the entire reservoir is being characterized by a performance from a single well which is obviously not the case. However, in the case of moderate to low permeability reservoirs we can analyze data on a "per well" basis as each well drains its particular volume and does not interfere with other wells in the system. Using single well assumption, Original Hydrocarbon In Place (OHIP) and reserve of the studying reservoirs can be obtained by summation of individual values of wells. It must also be noted that Buba and Blasingame PFM can be used to analyze not only production data of individual wells but also production data of whole reservoir (RPFM) which prepares a much smoother plot due to lower data fluctuations, lower human and truncation errors and more reliable and accurate recorded data for the whole reservoir. The estimations results are shown in Table 6 for the reservoirs "A" and "B".

Results show that no special attention has been paid to DCA, but it presents acceptable estimations without many requirements and complexities associated with MBE, particularly requirements for reservoir and fluid properties, average reservoir pressure data, and secondary calculations and iterations. It requires minimum data and only the characteristic behavior of pseudo-steady-state (or boundary dominated) must be exhibited.

Small differences in OGIP estimations can be attributed to violations of the single well assumption. As it was seen estimation results of both reservoirs show that their wells have high permeability values and negative skin factors, so gas mobility is high and the radius of investigation moves fast in the vicinity of wells and reaches the reservoir boundaries soon that cause overlap of the drainage area of individual wells. In addition, estimations for gas reserve and drainage area can be distinguished from the differences between RPFM and PFM as shown in Table 4.

Table 6. Estimation values for the reservoirs

Estimation Model	Reserve, TCF	OGIP, TCF	Err % of OGIP	Recovery Factor %	A, 1000 acres
		Reservoir A			
Arp	9.382	430.635	1518.928	2.178	9192
Fetkovich TC	113.911	1177.653	4327.269	9.672	32940
Blasingame TC	24.556	28.735	8.027	85.456	839
Agarwal-Gardner TC	24.554	28.733	8.019	85.455	839
Flowing Material Balance	24.083	28.185	5.962	85.446	875
PFM	23.45				
Reservoir PFM	23.166				
		Reservoir B			
Arp	18.226	75.854	418.803	24.027	1660
Fetkovich TC	159.895	190.181	1200.744	84.075	4233
Blasingame TC	13.418	16.115	10.22	83.264	387
Agarwal-Gardner TC	13.066	15.692	7.329	83.265	377
Flowing Material Balance	14.209	14.639	0.129	97.062	408
PFM	13.913				
Reservoir PFM	13.826				

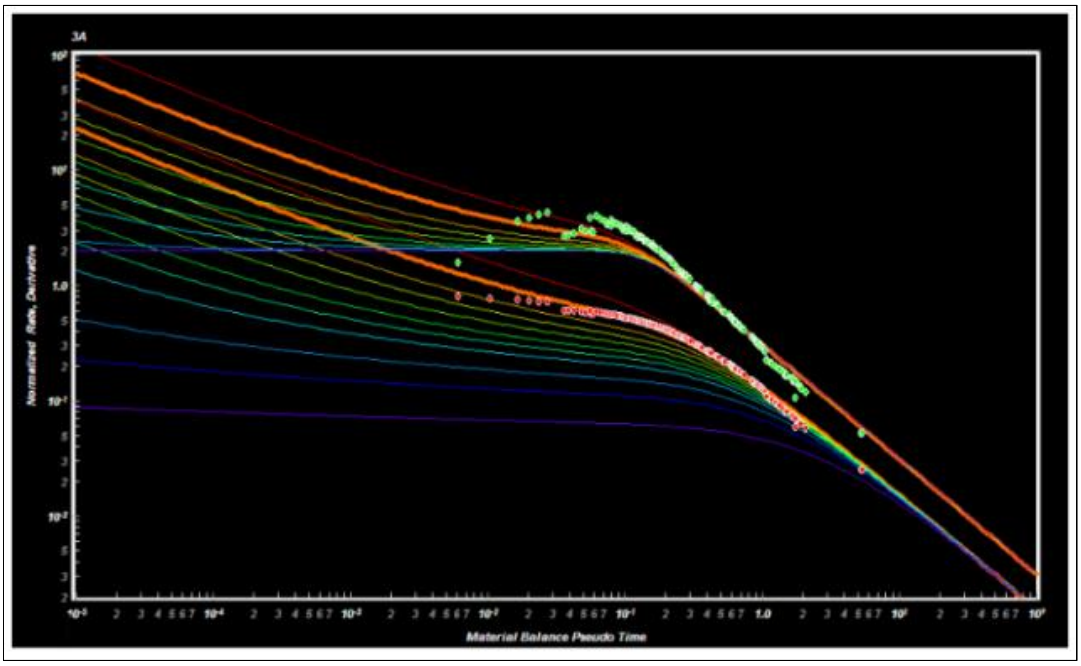
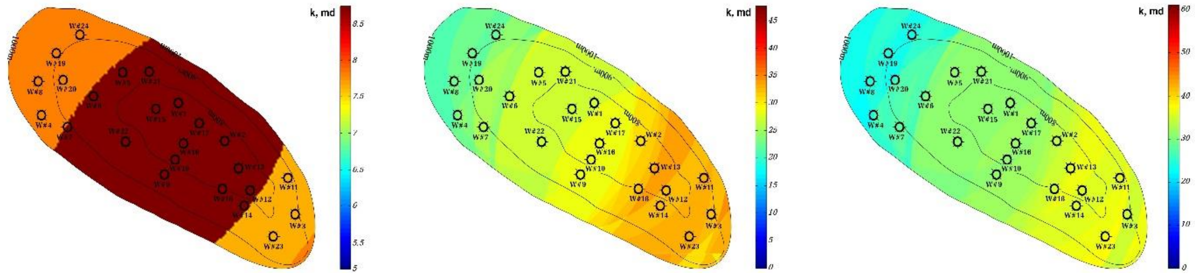


Fig. 4. Production data of well#3A on Agarwal-Gardner type curve

The MBE plot has historically been used to indicate the reservoir drive mechanism. DCA can also be used to distinguish the existence of pressure maintenance due to water influx. Comparing production data trend with a boundary dominated stem in type curves; if the trend initially obeyed the stem for a short time and later deviates above it there is pressure maintenance due to water influx otherwise, the reservoir is acting volumetrically and no water influx exists. Type curve matching showed that whole wells of the reservoir “A” deviate slightly from the stem which is due to water influx as it is shown in Fig. 4 for well#3A. Wells of the reservoir “B” also behave volumetrically and there is little or no pressure maintenance as it was proved by MBE. The results show close agreements with MBE studies.

The fracture distribution mapping is generated for reservoir “B” as shown in Fig. 5. It is seen that the maps of Agarwal-Gardner and Blasingame models show good accordance with expensive geological studies. Obviously, the fracture intensities in the central and the southeastern parts are higher than the northwestern sections. Improper results of the Fetkovich map can also be related to its unrealistic assumptions. It is worth mentioning that the procedure is applicable to both oil and gas reservoirs. It is noticeable to mention that the map can be useful to decide about the number and location of producing wells, detection of governing production mechanism of the reservoir, selection of the best EOR method, detection of underlying drivers, and management implementation to have maximum possible recovery from the drainage area.



Fetkovich map Blasingame map Agarwal-Gardner map

Fig. 5. Fracture distribution maps for reservoir "B"

Conclusions

- Simple but applicable and necessary procedures are introduced to correct initial production data.
- Limitations for production data analysis of NFRs using exclusive models have been detected and introduced.
- DCA can present acceptable estimations for radial permeability in NFRs.
- Agarwal-Gardner model gives the best results for reservoir fracture distribution mapping in NFRs. Blasingame model gives good estimation but less accurate than Agarwal-Gardner.
- Fetkovich model due to its unrealistic basic assumptions surely gives the most inaccurate results for permeability, skin factor, OGIP, and gas reserve.
- DCA skin values are negative because the fracture system acts both as a sink to the matrix system and as a conduit to production wells in NFRs.
- The flowing material balance model gives the best results for OGIP in NFRs and estimated values are mostly higher.
- Buba and Blasingame PFM give acceptable estimations for gas reserve. It can be used not only to analyze production data of individual wells but also field production data which presents a better plot and makes the analysis more reliable.
- Although DCA models require some data about the reservoir and producing well, they are still more desirable in comparison to MBE.
- DCA can be used to distinguish water influx successfully.

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