Studying Modern Decline Curve Analysis Models for Unconventional Reservoirs to Predict Performance of Shale Gas Reservoirs

Sondos M. Ahmed [a*], Hamid Khattab [a], and Mahmoud Tantawi [a]

[a] *Petroleum Engineering Department, Faculty of Petroleum and Mining Engineering, Suez University, Suez, Egypt*

Abstract

Among different reservoir forecasting methods, decline curve method stands as the simplest, least time consuming and least data requirement method. This is more proper for tight and unconventional reservoirs. Production from these unconventional reservoirs has grown dramatically around the world for the past few years.

In this study, decline curve models that are developed to predict performance of Unconventional Reservoirs are studied, analyzed, applied, and validated for different reservoir scenarios, some of them are simulated data that present different scenarios of flow regimes (4-cases) others are Field data for shale unconventional reservoirs. The models used in this thesis along with Arps Model are:

- Stretched Exponential Decline Production Decline (SEPD).
- Logistics Growth Model (LGM).
- Duong's Model.
- Power Law Exponential Decline (PLE).

Each model has its own parameters and equations. The main aim to select the best applicable model/s in term of simplicity of application, degree of fit and accuracy of EUR calculation. In addition, these methods are compared at various production times to investigate the effect of production time on prediction performance. As a part of validation process, all methods are benchmarked against simulation.

This work shows that all the methods predict various recovery and some fit certain simulation cases better than others. In addition, no single method could predict EUR precisely without reaching BDF. Using this work, engineers could select the best applicable model to predict EUR after identifying the simulation case that is most analogous to their field wells.

Keywords

Decline curve analysis, estimated ultimate recovery, unconventional reservoirs, shale gas reservoirs, and Boundary Dominated flow

Introduction

Unconventional reservoirs are essentially any reservoir that requires special recovery operations outside the conventional operating practices. [7] They require assistance to be produced at economical flow rates and so produce economic volumes of oil/gas, these assistances may be stimulation or steam injection. The success of developing Unconventional Reservoir depends on drilling a horizontal well with many transverse fractures in order to create a Simulated Reservoir Volume (SRV).[1]

Production from unconventional reservoirs, especially, shale reservoirs has been grown massively all over the world in the past years. A recent survey in 2016 shown in figure 1, that more than 25,000 wells have been drilled producing about 40 BCF/day. The Gas Technology

Institute estimates that organic shale reservoirs in the United States contain up to 780 TCF of gas.[9]

Studies and researches show that about 80% of the reservoirs are unconventional in which the unconventional oil is almost equal to the conventional oil, and the unconventional gas is about 8 times that of conventional gas which made production from unconventional reservoirs of great importance and so the prediction of their performance. [3]

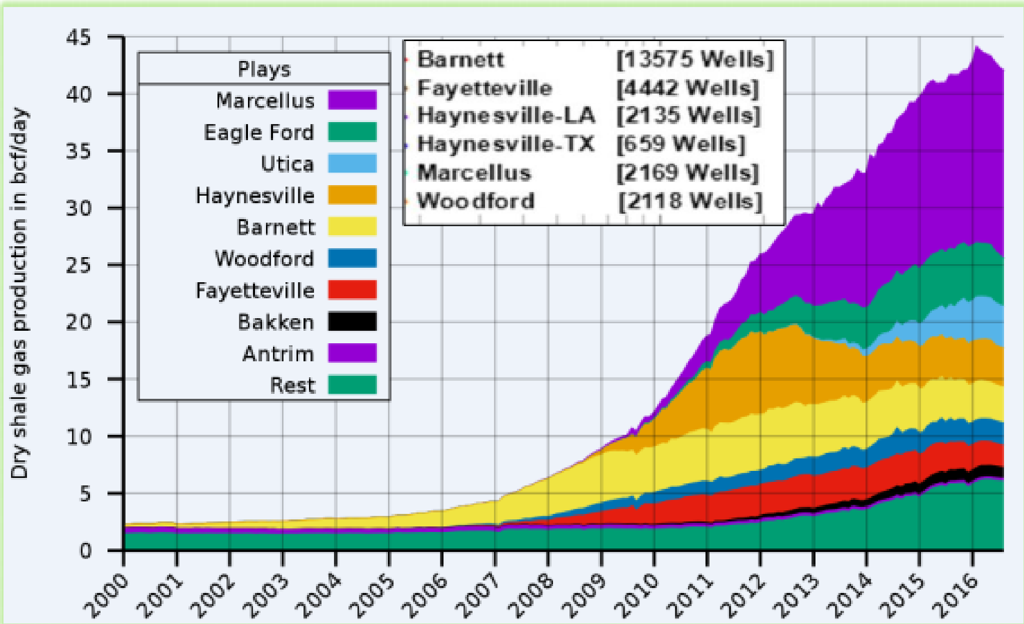

Figure 1 US production from shale gas and the number of wells drilled in different shale plays. (Source: US Energy Information Administration)

Decline Curve Analysis (DCA) is one of the most known and simplest methods in predicting the future production of oil and gas wells. The main purpose of DCA is to generate a forecast of future production rates and determine the Estimated Ultimate Recovery. The major disadvantage of DCA is that it depends only on production history, so the accuracy can easily overestimate EUR or underestimate the Production rates. It also does not consider any time used in equipment or labour changes, but though DCA methods are still used up to now.

Production decline analysis for unconventional reservoirs encounters many challenges. The extreme low permeability in them results in a long transient period that may last for years and the drainage area of the reservoir cannot be determined. The traditional Arps DCA model therefore cannot be applied as its main assumption is the production is limited to BDF. In addition, usually in unconventional reservoirs linear flow is the main flow regime not the radial flow as shown in figure 2. So other modern models are developed to match the decline behaviour encountered in the Unconventional Reservoir although none of these methodologies can be projected to provide a unique prediction of well performance and predict the EUR.

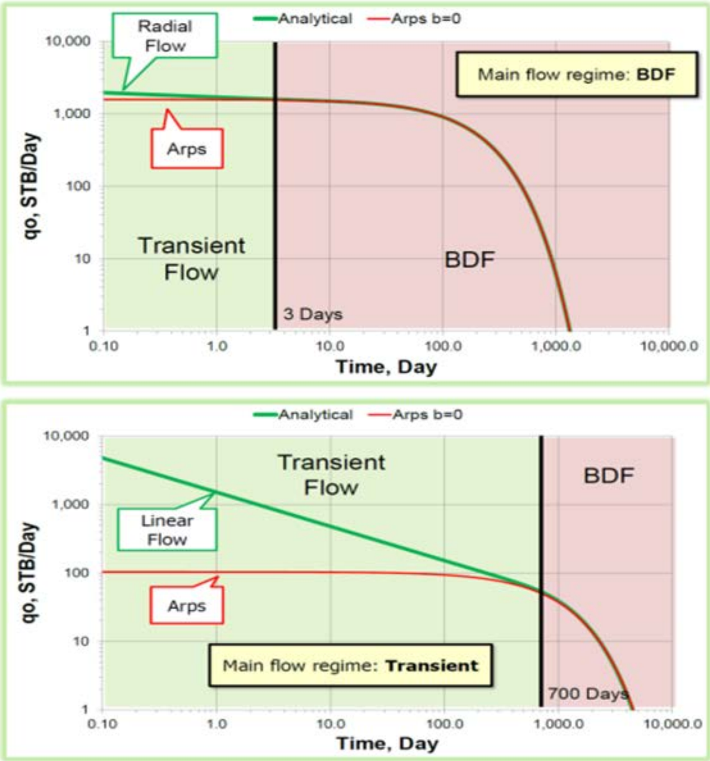

Figure 2 Comparison between the performance of two cases of a vertical well in a conventional reservoir and a horizontal well in a shale reservoir with multi-stage fracturing, and the Arps exponential decline curve.

Methods and Materials

Conventional Reservoirs DCA (Arp's Method)

Arps,1944, classified the decline curve using loss ratio method into three types and defined rate vs. time and rate vs cumulative production. The three types are Exponential, Harmonic and Hyperbolic decline curves during BDF. All these models have b ranges from 0 to 1. Hyperbolic Decline (0 < b < 1) was well chosen to be the general model and the two other models (Exponential (b = 0) and Harmonic (b = 1)) were derived from it, that is well described in figure 3.[2]

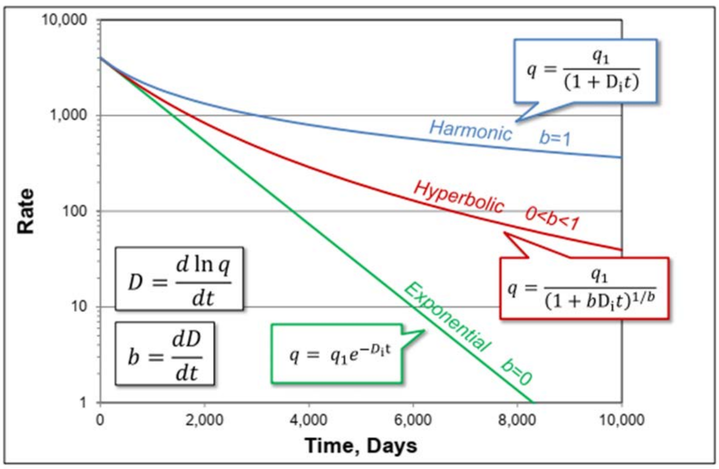

Figure 3Plot of three Arps DCA models on a Semi-log graph[10]

The decline rate of the three Arps' models is represented by:

$$D = \frac{1}{q}\frac{dq}{dt} = -Kq^b$$

By integration in most cases, it gives:

$$q = \frac{q_i}{(1 + D_i bt)^{1/b}}$$

Arps' three models can then be summarized in the following table:

Table 1Equations of the three Arps DCA models.

Exponential Decline	Hyperbolic Decline	Harmonic Decline
b = 0	0 < b < 1	b = 1
$D(t) = D_i$	$D(t) = \frac{D_i}{1 + D_i * b * t}$	$D(t) = \frac{D_i}{1 + D_i * t}$
$q = q_i e^{-D_i t}$	$q = q_i(1 + D_i bt)^{\frac{-1}{b}}$	$q = q_i(1 + D_i bt)^{-1}$
$Q = \frac{q - q_i}{D_i}$	$Q = \left[\frac{q_i}{D_i(1-b)}\right]\left[1 - \left(\frac{q}{q_i}\right)^{1-b}\right]$	$Q = \frac{q_i}{D_i}\ln\frac{q_i}{q}$

Unconventional DCA Models

Power Law Exponential Decline. (PLE)

Spivey et al.,2001, showed that when Arps loss ratio (1/D) is constant the decline will be Exponential Decline while the derivative of the loss ratio (Arps Decline Exponent" b") is constant the decline will be Hyperbolic Decline.[11]

Ilk et.al.,2008, evaluated the applicability of hyperbolic decline to several tight and fractured gas wells, they attributed that the "non-hyperbolic" (b value is not constant) behaviour observed is due to a variety of reasons such as multilayer effects, transient flow and the increasing "contacted-gas-in-place" in the case of low permeability/heterogeneous reservoirs.In their study, an alternate computation of the D and b-parameter using rate cumulative data is provided as shown by the following equations[8]

$$D = \frac{-dq}{dQ}$$

$$b = q\frac{-d\left(\frac{1}{D}\right)}{dQ}$$

$$y = ax^{-b} + c$$

Where c is a coefficient of uncertainty and then decline rate follows a power law decline in the early time and then become approximatelyconstant (an exponential decline) in the late time and then PLE "D" and "b" equations is represented by the following:

$$D = D_\infty + D_1 t^{-(1-n)}$$

$$b = \frac{-D_1(n-1)t^n}{(D_\infty t + D_1 t^n)^2}$$

Recalling the D-parameter definitionand integrating gives PLE rate-time equation:

$$q = q_i exp\left(-D_\infty t + \left(\frac{D_1}{n}\right) t^n\right)$$

Where D_∞ is the decline rate as t approaches infinity.

Cumulative fluid production is given by $Q = \sum q$as it is very difficult to obtain an analytical equation for cumulative production.

Stretched Exponential Production Decline (SEPD)

Valko,2009, proposed a totally empirical DCA method that is mainly different from Arps model. This method is characterized by a finite EUR prediction as production time increases, applicability in transient and BDF regimes, and a limited number of parameters to be determined. These parameters are exponent n (similar to "b" in Arps model), characteristic time parameter "τ" and the initial flow rate q_i (in sometimes taken as largest observed rate)[12]

1. The SEPD rate equation given by: $q = q_i exp\left(-\left(\frac{t}{\tau}\right)^n\right)$ which can be presented in the dimensionless form by: $q_D = \frac{q}{q_i} = exp\left(-\left(\frac{t}{\tau}\right)^n\right)$

2. Cumulative Production given by: $Q = \frac{q_i \tau}{n}\left\{\Gamma\left(\frac{1}{n}\right) - \Gamma\left[\frac{1}{n}, \left(\frac{t}{\tau}\right)^n\right]\right\}$, Where the first term inside the brackets is the complete gamma functionand the second term is the incomplete gamma function.

3. Estimated Ultimate Recovery "EUR" given by: $EUR = \frac{q_i \tau}{n}\Gamma\left(\frac{1}{n}\right)$

4. Recovery Potential "r_p" given by: $r_p = 1 - \frac{Q}{EUR} = \frac{1}{\Gamma\left(\frac{1}{n}\right)}\left\{\Gamma\left[\frac{1}{n}, ln\left(q_D\right)\right]\right\}$

Duong Method

Duong,2011, presented a model for predicting performance of unconventional reservoirs flowing under long transient flow, he believed that plotting q/Q vs. time on a log-log graph paper yields straight line with a unit.[6]This model suits the fracture dominated flow and considers matrix contribution is negligible, it adapts with the expanding stimulated reservoir volume (SRV) condition which means that the connected fracture density in the fractured area must increase with time due to local in-situ stresses changes while fracture depletion.[5]

q/Q used in the log-log plot can be described by the following power law equation:

$$\frac{q}{Q} = at^{-m}$$

Where m is a positive number

From this equation Duong cumulative rate and Duong rate equations were derived given by the following equations respectively:

$$Q = \frac{q_i}{a} exp\left[\left(\frac{a}{1-m}\right)(t^{1-m} - 1)\right]$$

$$q = q_i t^{-m} exp\left[\left(\frac{a}{1-m}\right)(t^{1-m} - 1)\right]$$

Logistic Growth Model (LGM)

Logistic Growth Models (LGM) are based on the concept that growth will continue to a certain limit, the maximum growth size possible is referred to as the carrying capacity (K).

The first one to introduce the concept of LGM in petroleum industry was Hubbert,1956. He used this concept to predict cumulative production of different oil fields. Clark et.al.,2011, introduced a three parameters LGM to predict production [4]. Applying this concept to oil and gas production, LGM flow rates and LGM cumulative rate equations are given by the following equations respectively:

$$q = \frac{Knat^{n-1}}{(a + t^n)^2}$$

$$Q = \frac{(K)t^n}{a + t^n}$$

Where K is better defined as EUR.

Matching Data

The objective method of calculation of parameters of different DCA models is the sum of squares, by which a regression is made to get valves of the parameters that gives the least error.

Here are the steps, rules, and procedures for most of the DCA models discussed in this paper:

1. Select only 80-90% of production history data for matching and reserve the rest for validation of the DCA model used.
2. Using Microsoft Excel regression to calculate the parameters that gives the least square error.
3. Matching will be with cumulative production not with flow rate.

Some important notes must be taken into consideration:

1- All DCA methods is applied.
2- Enough production history data must be available at least 365 days of flowing.
3- All/Most of the DCA models will match the production data, but the validation will be on the10-20% of the production history data that were not used in the matching process.

Estimation of EUR.

EUR is determined using the following procedures:

1- Record the last cumulative data reported from production history.
2- Match Data using different DCA models.
3- Extrapolate the DCAs until reach economic rate or time.

4- Calculate reserve.
5- EUR will be equal to the last cumulative data observed plus the reserve.

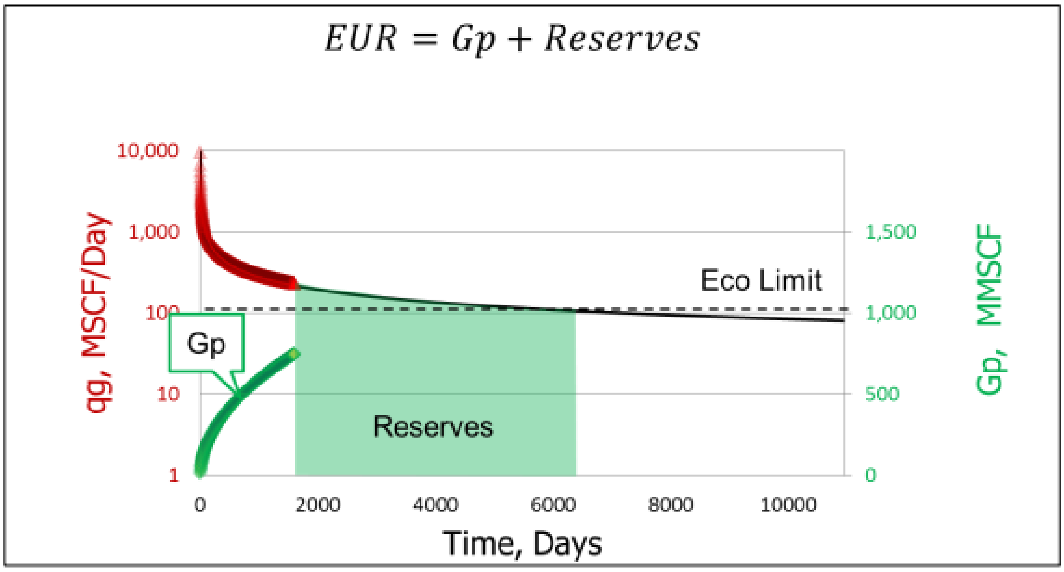

Figure 4Calculation of EUR.

It must be known that no production trend is expected as all DCA models may predict different production trends therefore should be all applied to give engineers a range of estimates.

Simulation Model

Unconventional reservoirs,more specifically shale reservoirs, which are completed with many hydraulic fractures are best described by two models: Homogeneous model that assumes that fluid flows from matrix to hydraulic fractures to well and Naturally Fractured model that assumes that fluid flow from matrix to natural fractures to hydraulic fractures and then to the well.

Both homogeneous and naturally fractured models may be very complex, so for simplicity we have made two assumptions. The first one is that the hydraulic fractures have infinite conductivity as the matrix permeability is extremely low relative to permeability of the fractures and could result in four decline scenarios:

1- Linear flow for entire production time. (linear)
2- Linear flow followed by BDF. (linear-BDF)
3- Linear flow for the entire production time preceded by Bilinear flow. (Bilinear-Linear)
4- Bilinear flow followed by Linear flow and finally reach BDF. (Bilinear-Linear-BDF)

This assumption is acceptable as linear flow occurs in both models and can be preceded by bilinear flow if there are natural fractures and is followed by BDF if boundaries is reached however, BDF usually does not occur through the economic production life depending on the matrix permeability.

The second assumption is that all wells have equally spaced hydraulic and natural fractures that will result in symmetry which will make simulation faster and easier as shown in the following figure:

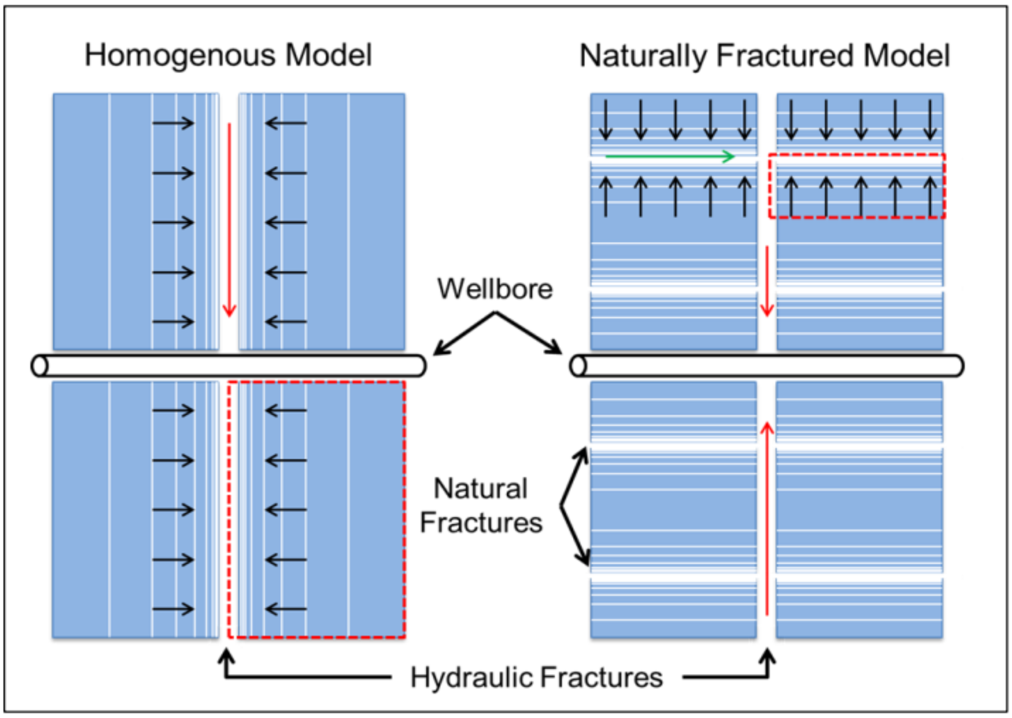

Figure 5: Schematic showing Homogenous model and Naturally Fractured Model with simulated segments.

The result of simulation for 30 years for the 4 possible declines are shown in the following figures:

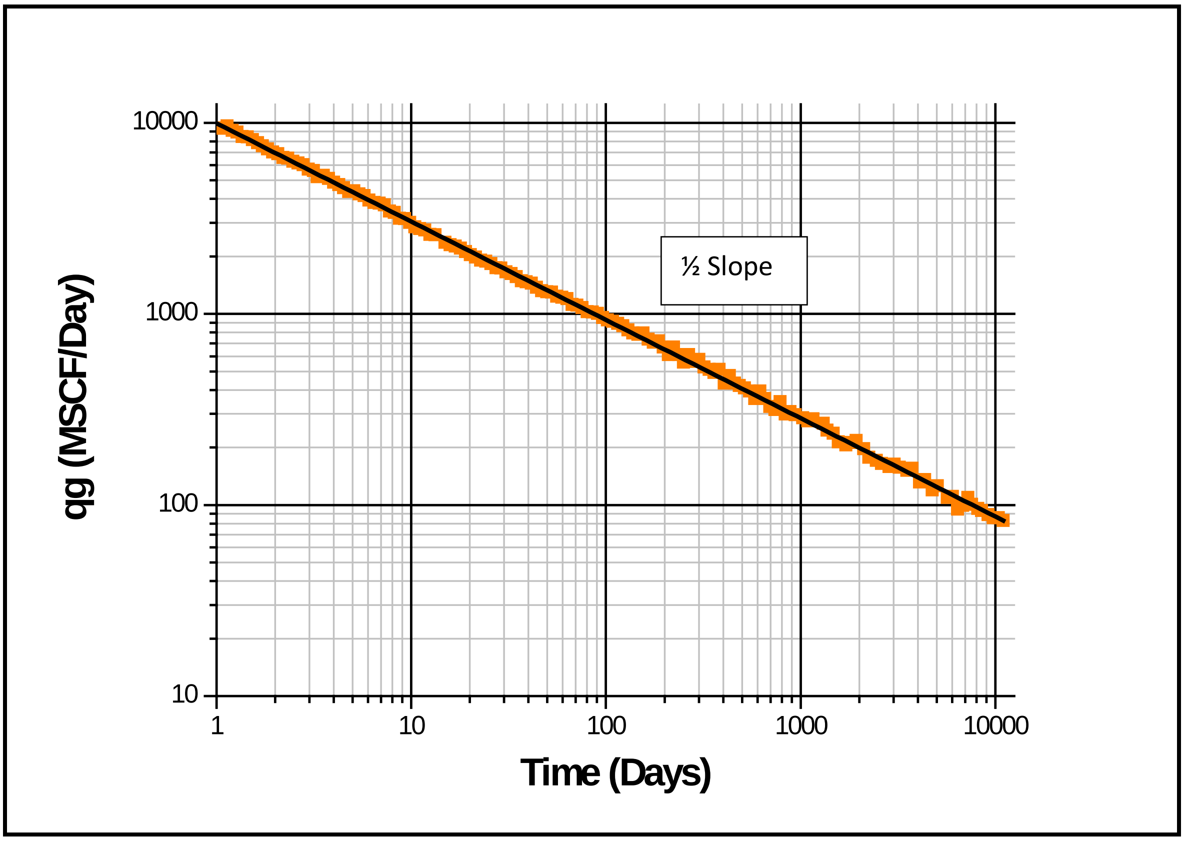

Figure 6 case 1 Linear Flow for entire production life.

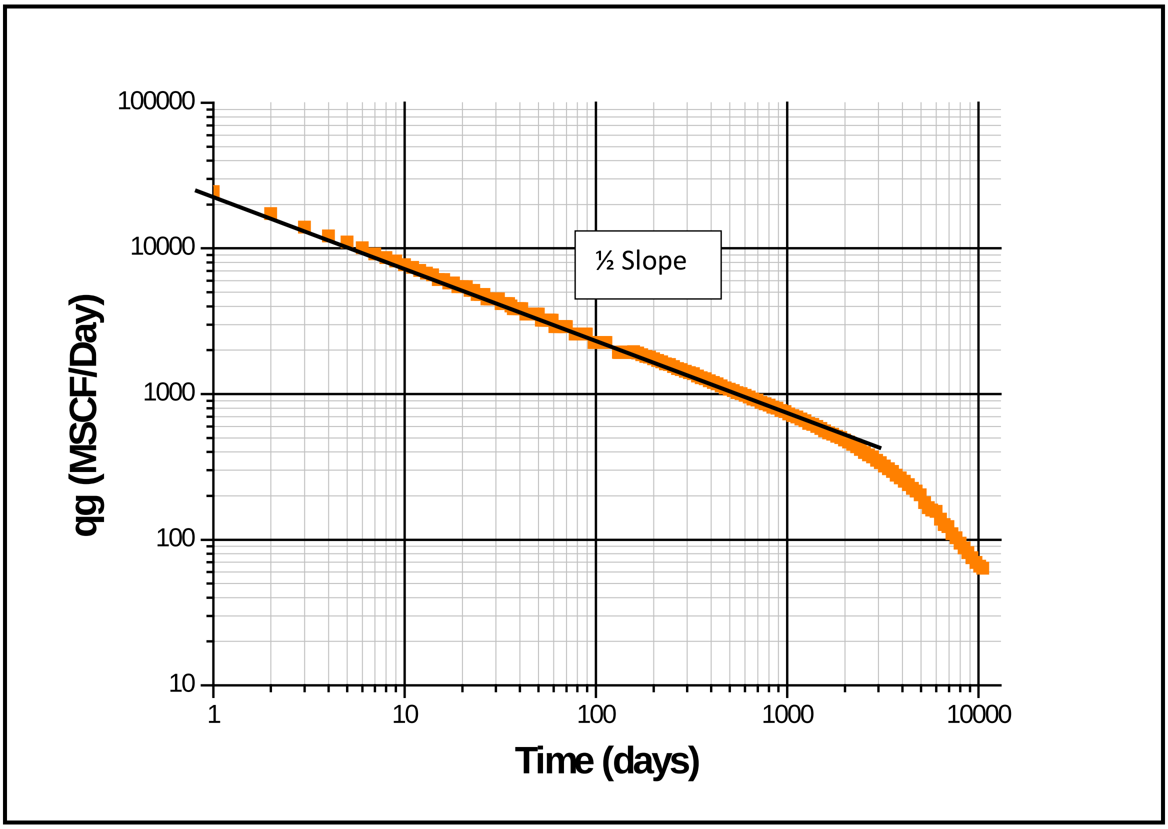

Figure 7. Case 2: Linear flow followed by BDF.

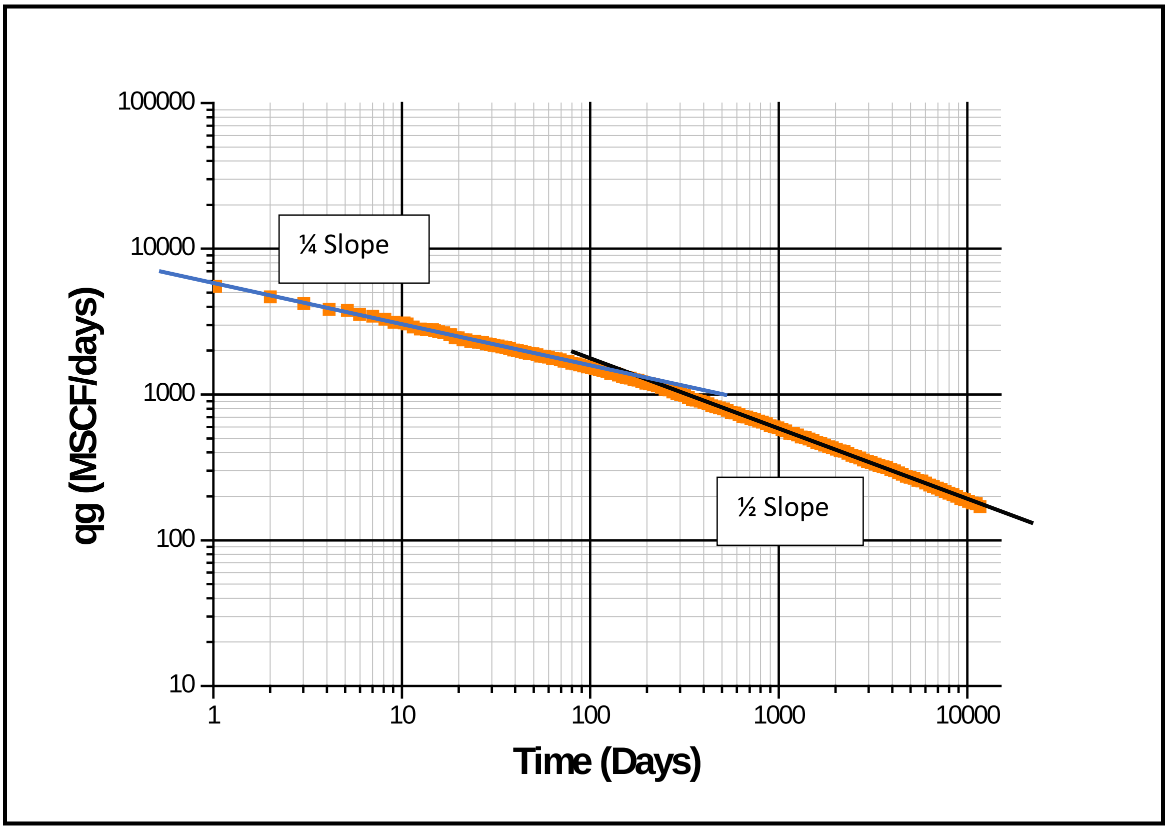

Figure 8. Case 3: Bilinear followed by Linear Flow.

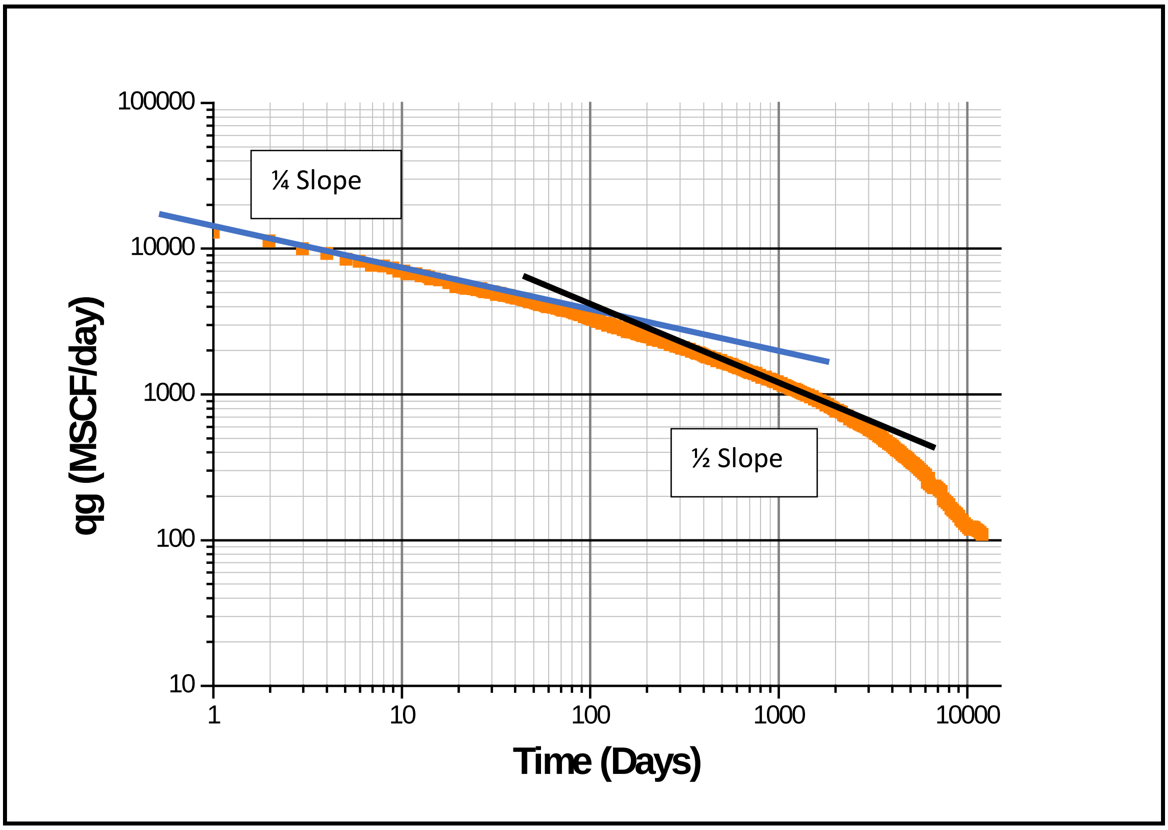

Figure 9. Linear flow preceded by Bilinear flow and followed by BDF.

Effect of time on forecast.

The aim of this section is to test the effect of production time on the DCA methods. Data from all cases are cut at different time of production and predicted by all models.

<u>Case 1: Linear Flow.</u>

For data after only production of 100 days, all methods except SPED extrapolated linearly and predicted the correct production. The SEPD model does not maintain the straight line fit and curved downwards so it gave wrong prediction as shown in Figure 10.

For data after production of 1000 days of production, all methods except for SEPD extrapolated linearly and predicted the correct production as shown in Figure 11.

For data after production of 8000 days, all methods extrapolated linearly and predicted the correct recovery as shown in Figure 12.

<u>Case 2: Linear – BDF.</u>

For production times before BDF all methods behaved as case 1 and none of the DCA models predicted the right correct trend as the start of the BDF is unknown and cannot be calculated from the available production data of 100 days as shown in Figure 13.

For production cut at 3000 days after the start of BDF methods results have been improved but still giving an over estimation of production as shown in Figure 14.

At 8000 days of production, methods improvement increased and only PLE method gave a reasonable forecast and correct recovery as shown in Figure 15.

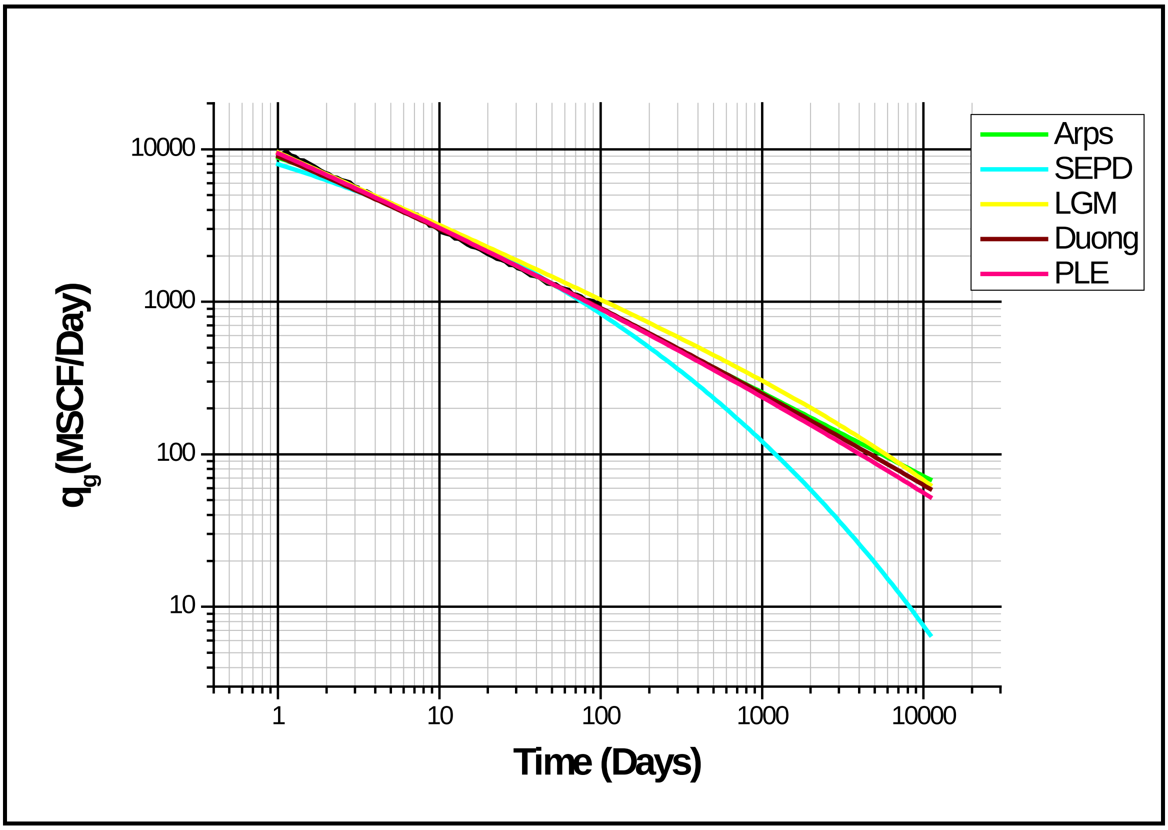

Figure 10. Prediction comparison of case 1 after 100 days of production.

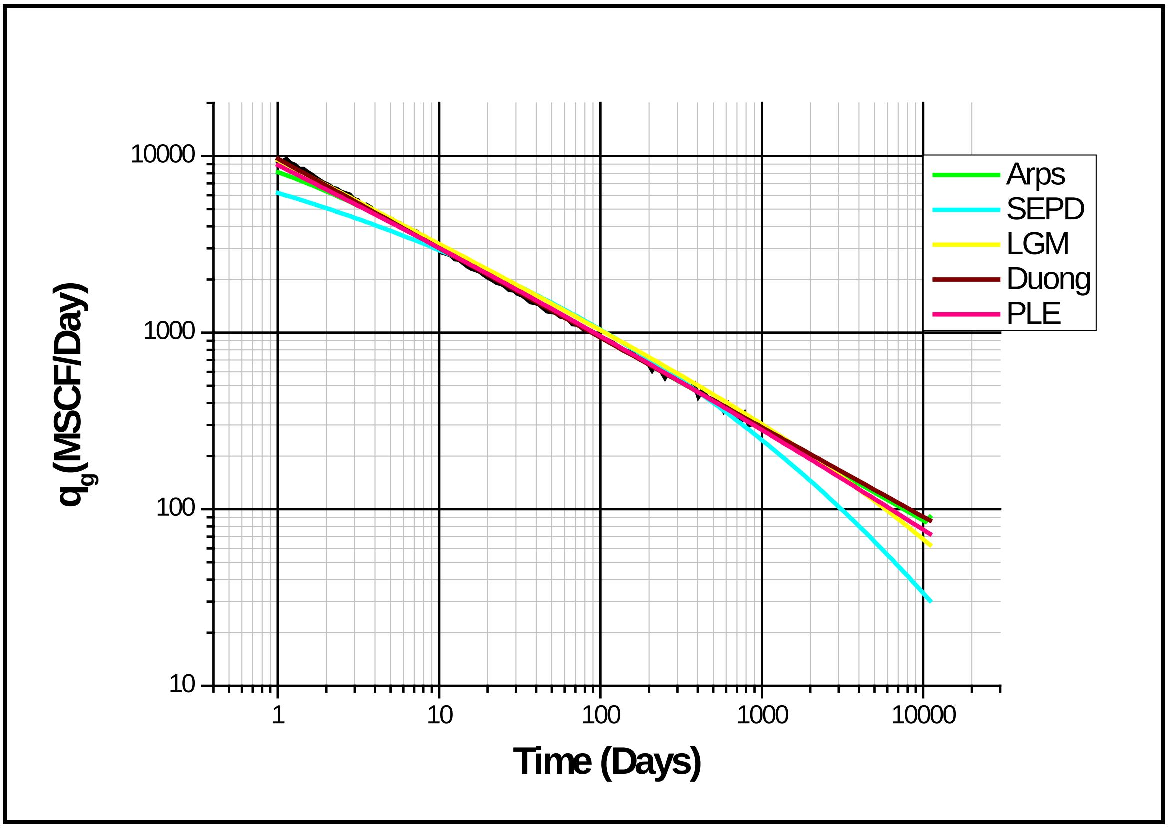

Figure 11 Prediction comparison of case 1 after 1000 days of production.

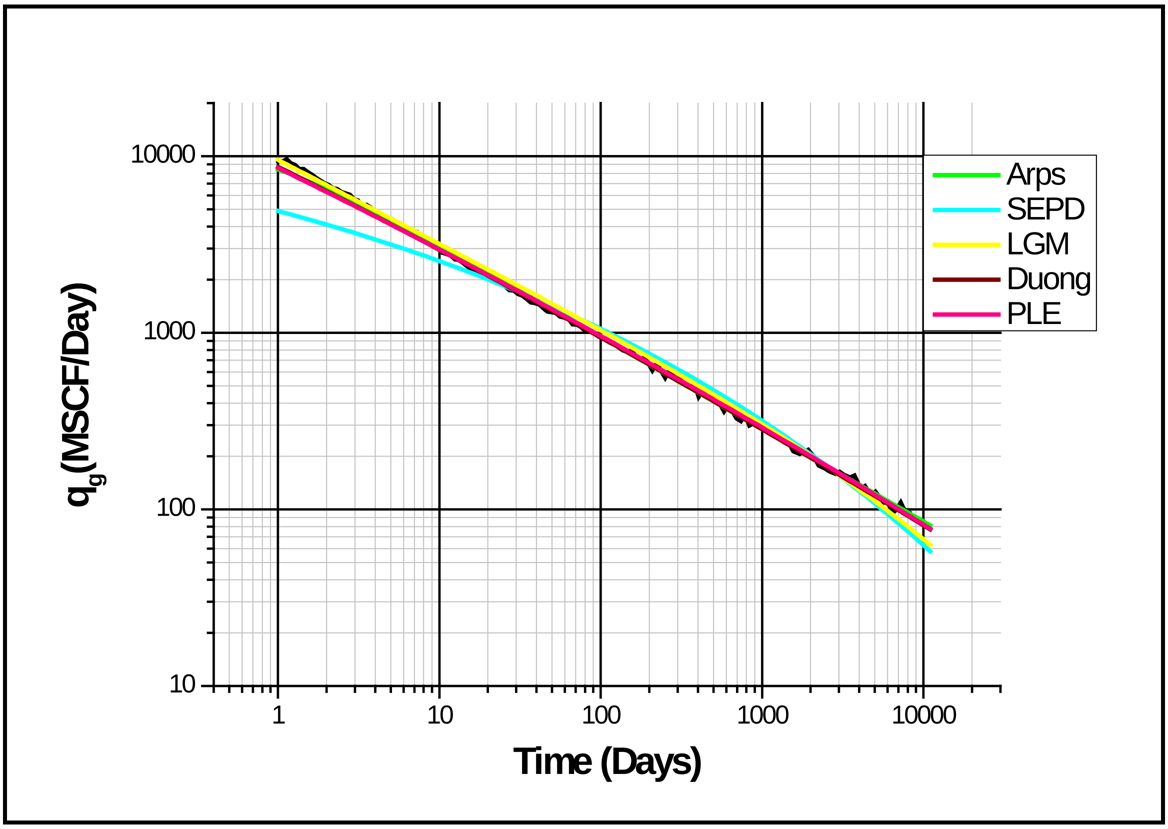

Figure 12 Prediction comparison of case 1 after 8000 days of production.

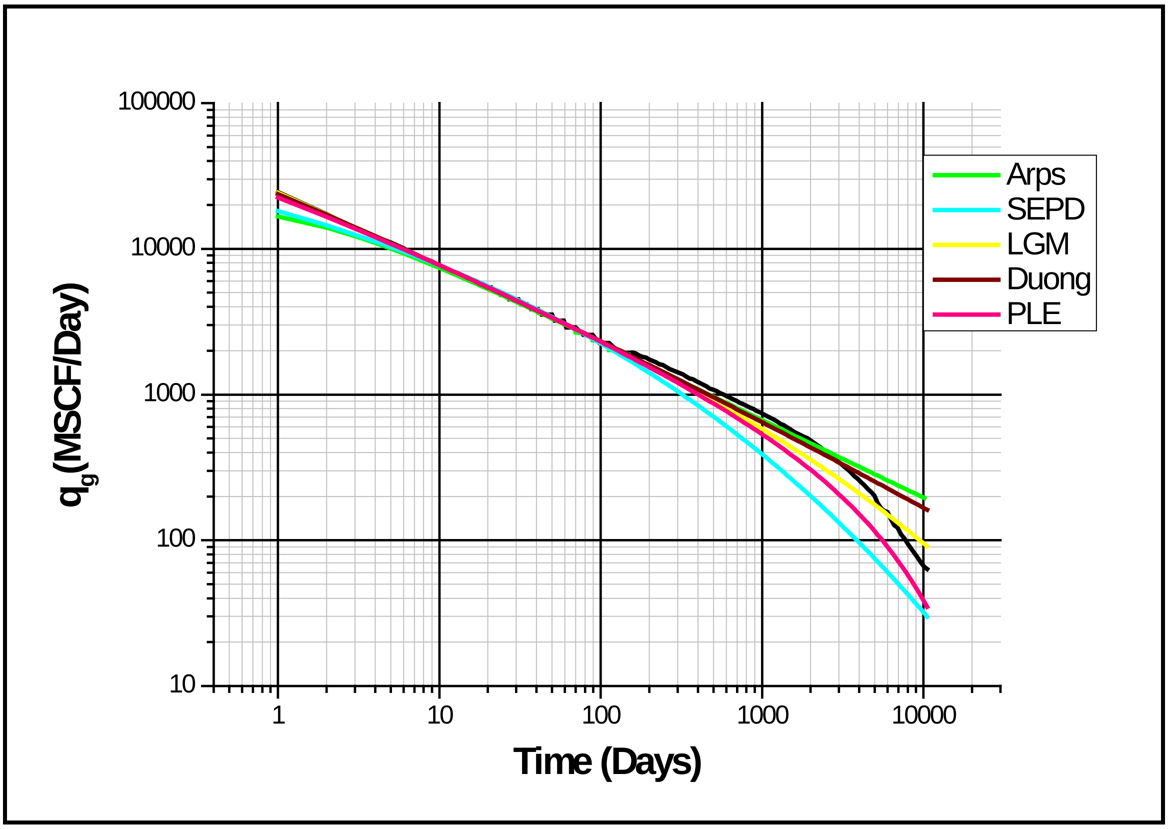

Figure 13 Prediction comparison of case 2 after 100 days of production.

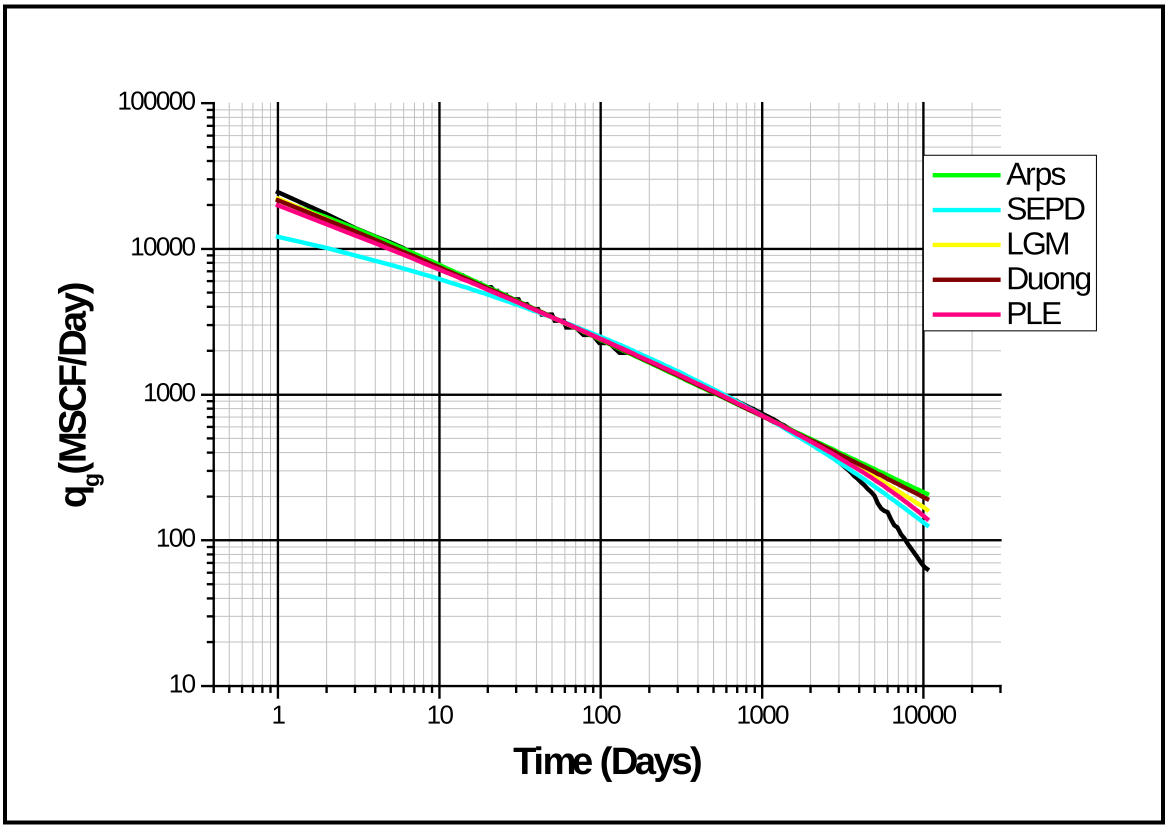

Figure 14 Prediction comparison of case 2 after 3000 days of production.

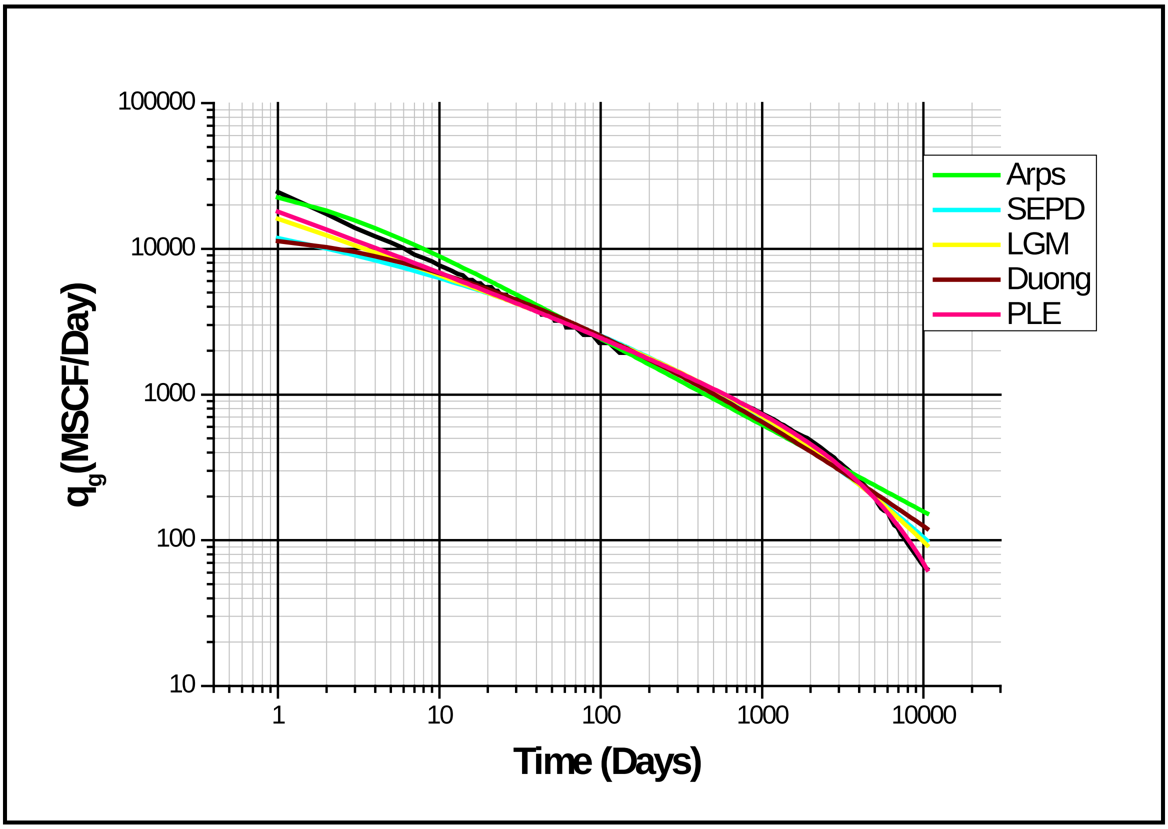

Figure 15 Prediction comparison of case 2 after 8000 days of production.

Case 3: Bilinear-Linear flow

At production cut of 100 days none of the method predicted the right production except that for SEPD that had a close fair correct prediction as shown in Figure 16. for 1000 days of production where Linear flow has started SEPD and Duong methods have been quietly improved and gave correct prediction, while PLE and LGM gives underestimation and Arps gave overestimation of recovery as shown in Figure 17. At 8000 production days all methods predicted the correct recovery except that Arps at the early time has fair match as shown in Figure 18.

Case 4: Bilinear-Linear-BDF

For early production cut at 100 days, none of the methods gave the correct prediction as its difficult to know the start of the Linear flow and BDF for the available data, however LGM is the only method that gave a fair correct prediction and that just by a coincidence and at different production may not give that result as shown in Figure 19. At production cut of 1000 days, none of the methods have predicted the correct recovery because of the unknown start time of BDF as shown in Figure 20, but models' prediction has been slightly improved. At production cut of 3000 at the start of BDF only PLE method predicted the correct recovery and all other methods failed to that as shown in Figure 21. At 8000 production days no great change of results from 3000 days except that the prediction of other methods has been improved yet given overestimated recovery as shown in Figure 22.

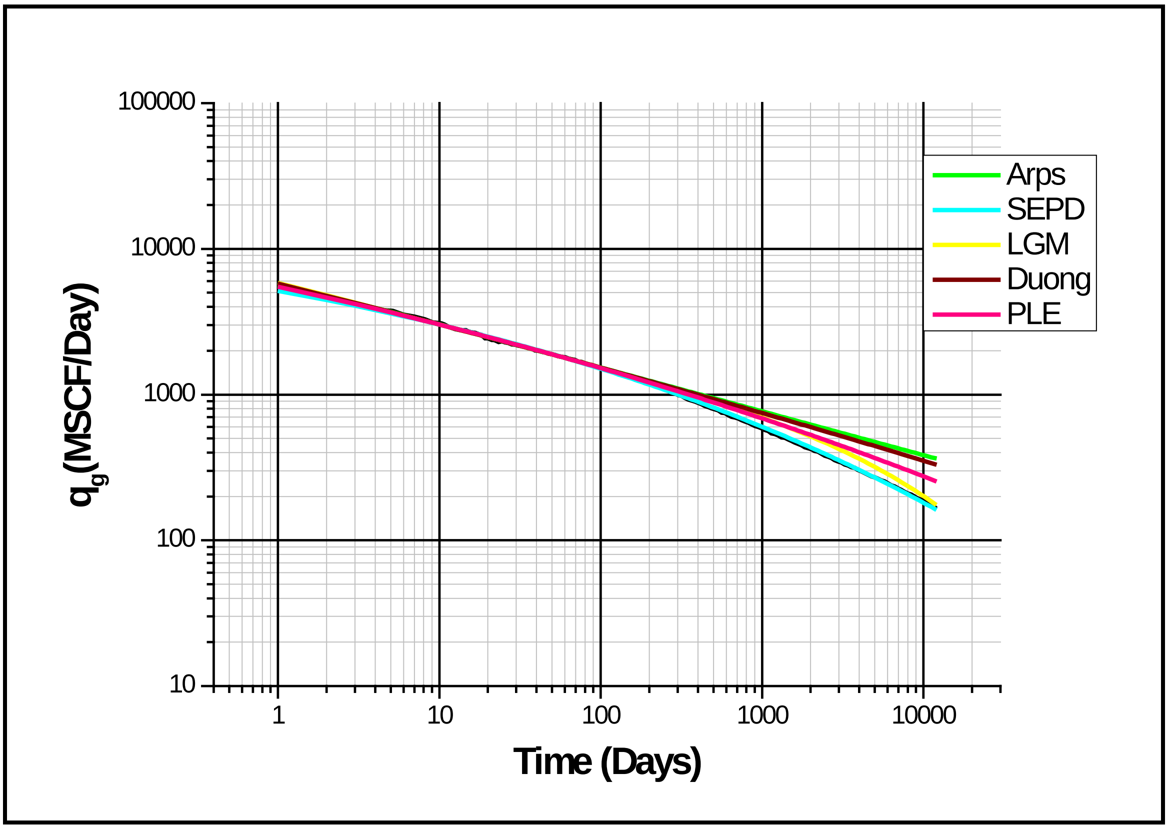

Figure16 Prediction comparison of case 3 after 100 days of production.

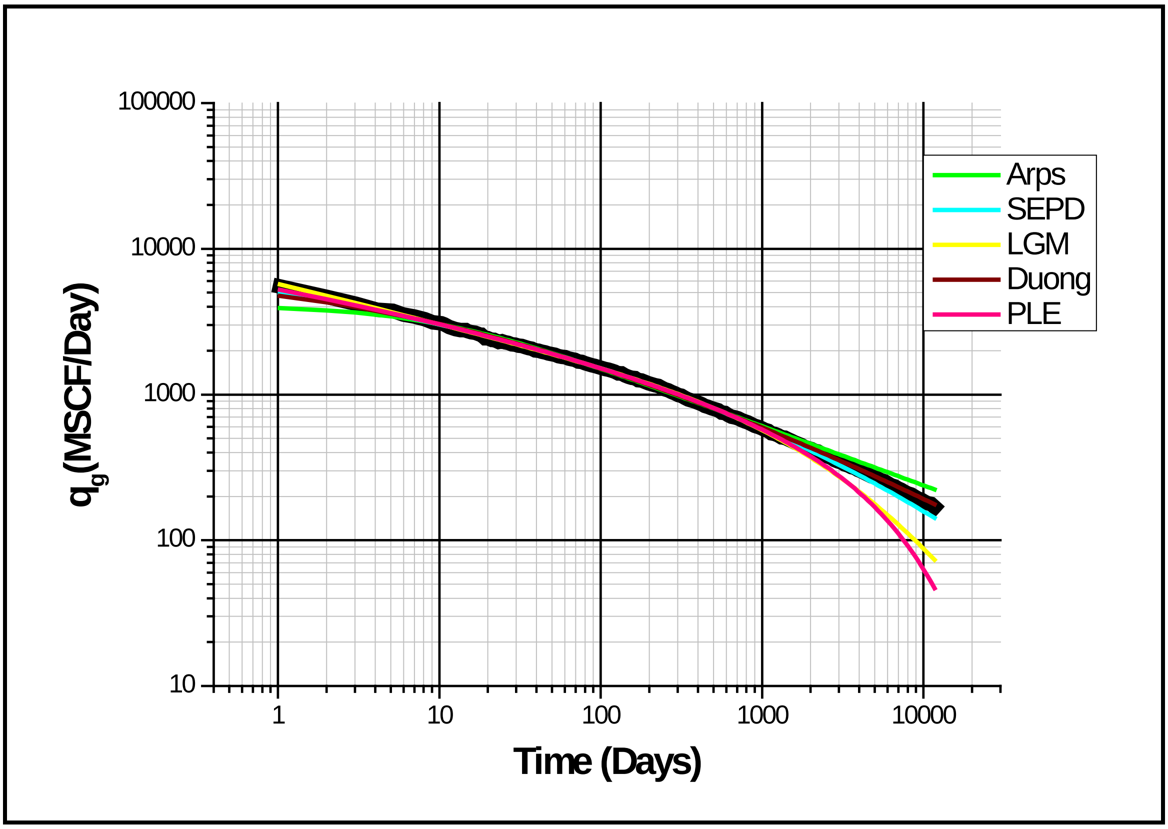

Figure 17 Prediction comparison of case 3 after 1000 days of production.

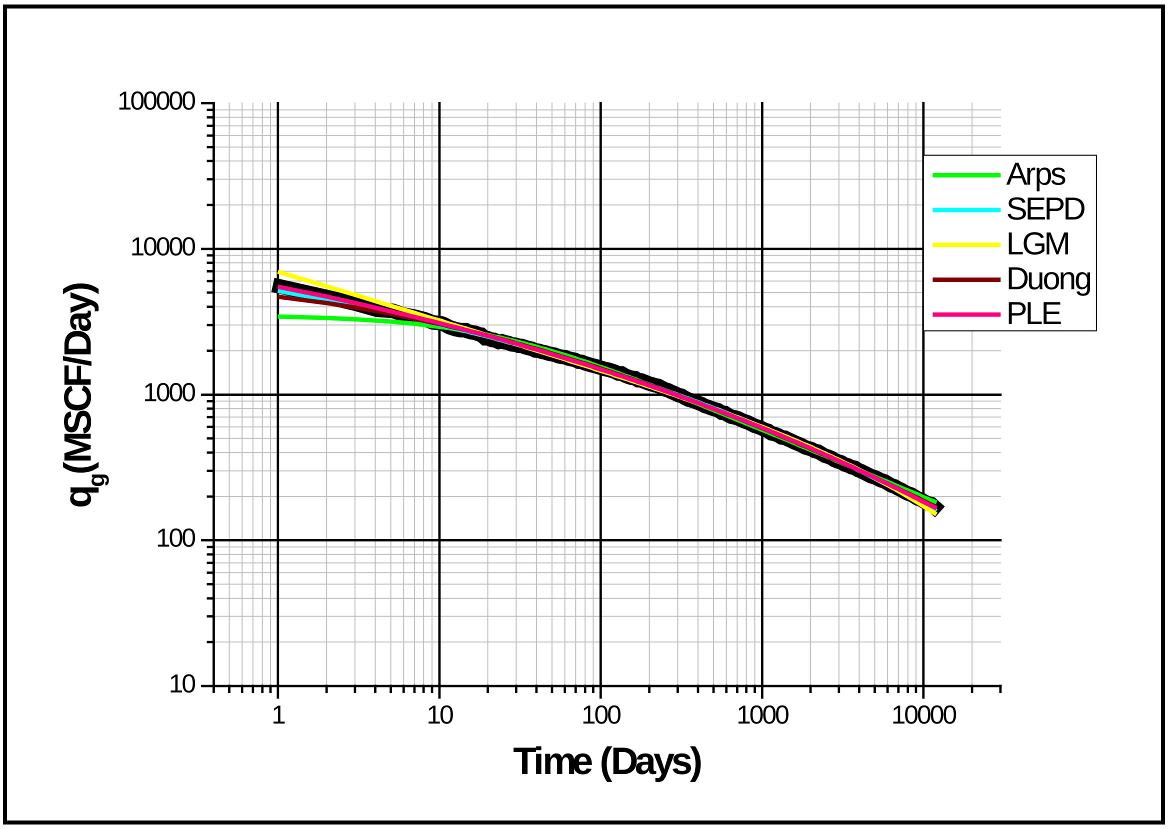

Figure 18 Prediction comparison of case 3 after 8000 days of production.

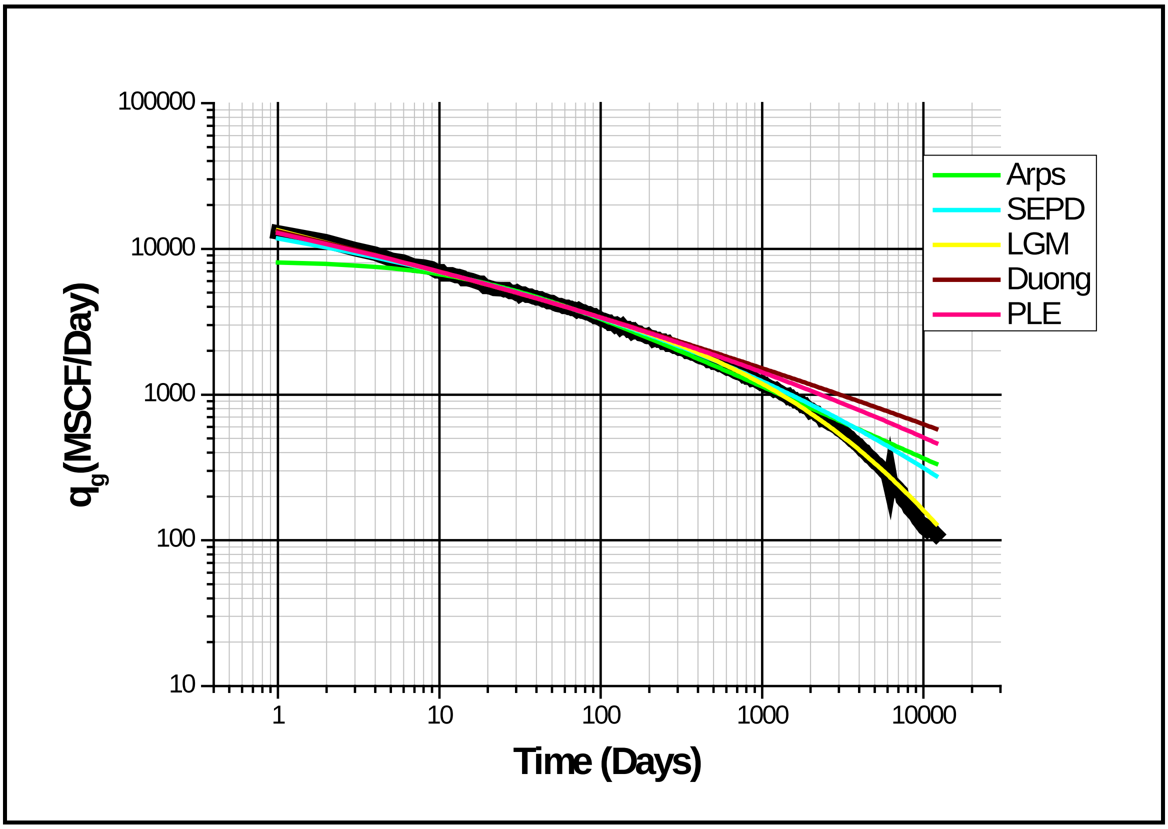

Figure 19 Prediction comparison of case 4 after 100 days of production.

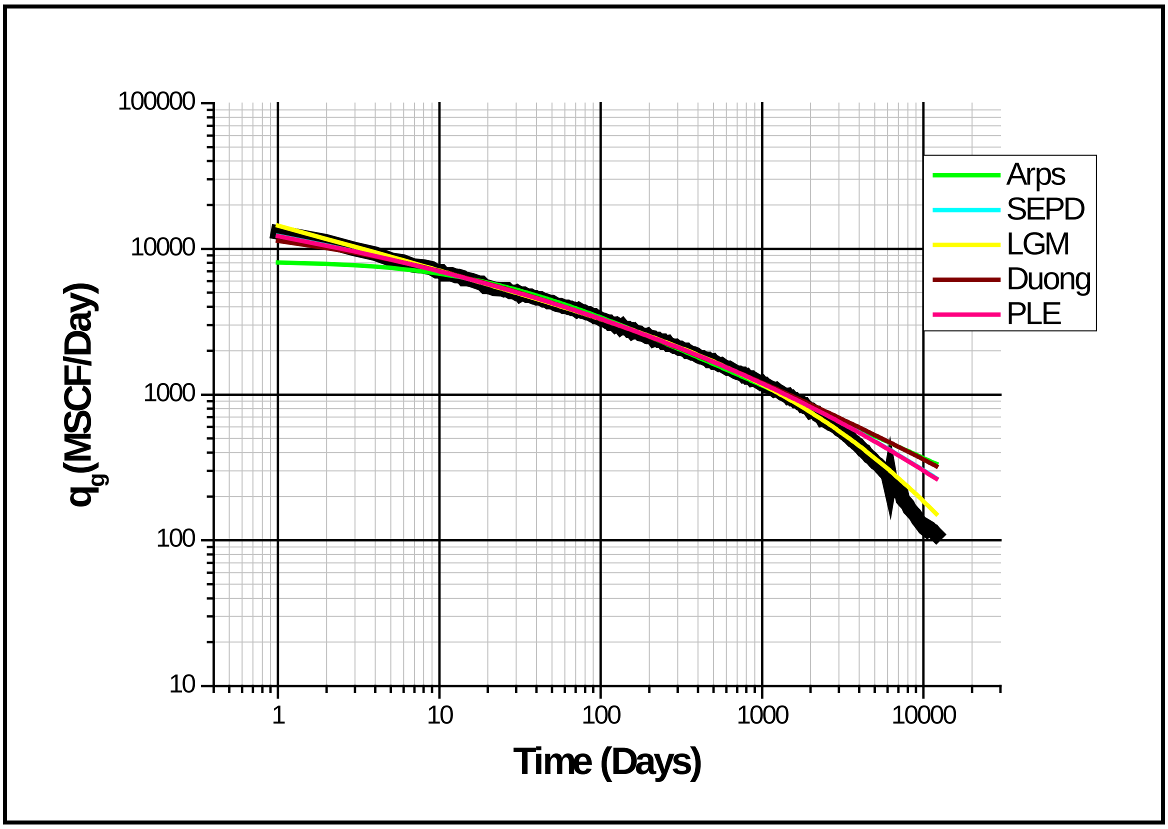

Figure 20 Prediction comparison of case 4 after 1000 days of production.

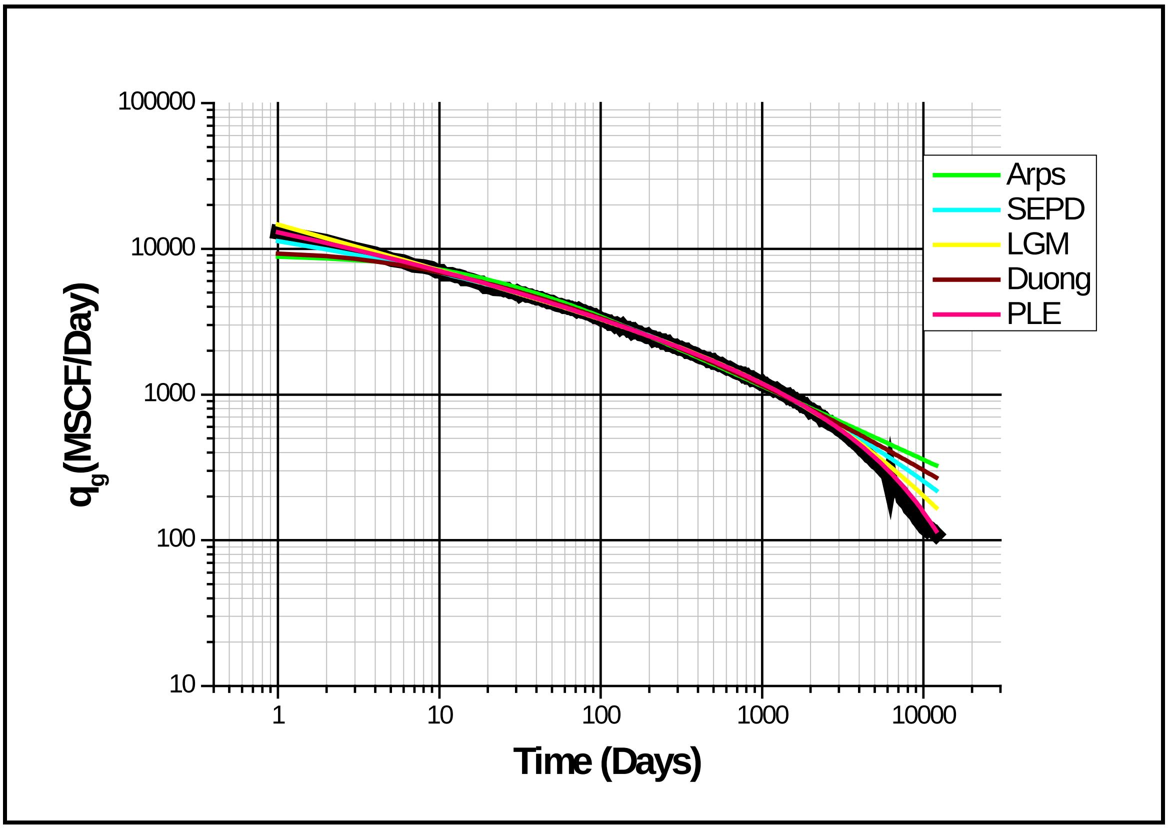

Figure21 Prediction comparison of case 4 after 3000 days of production.

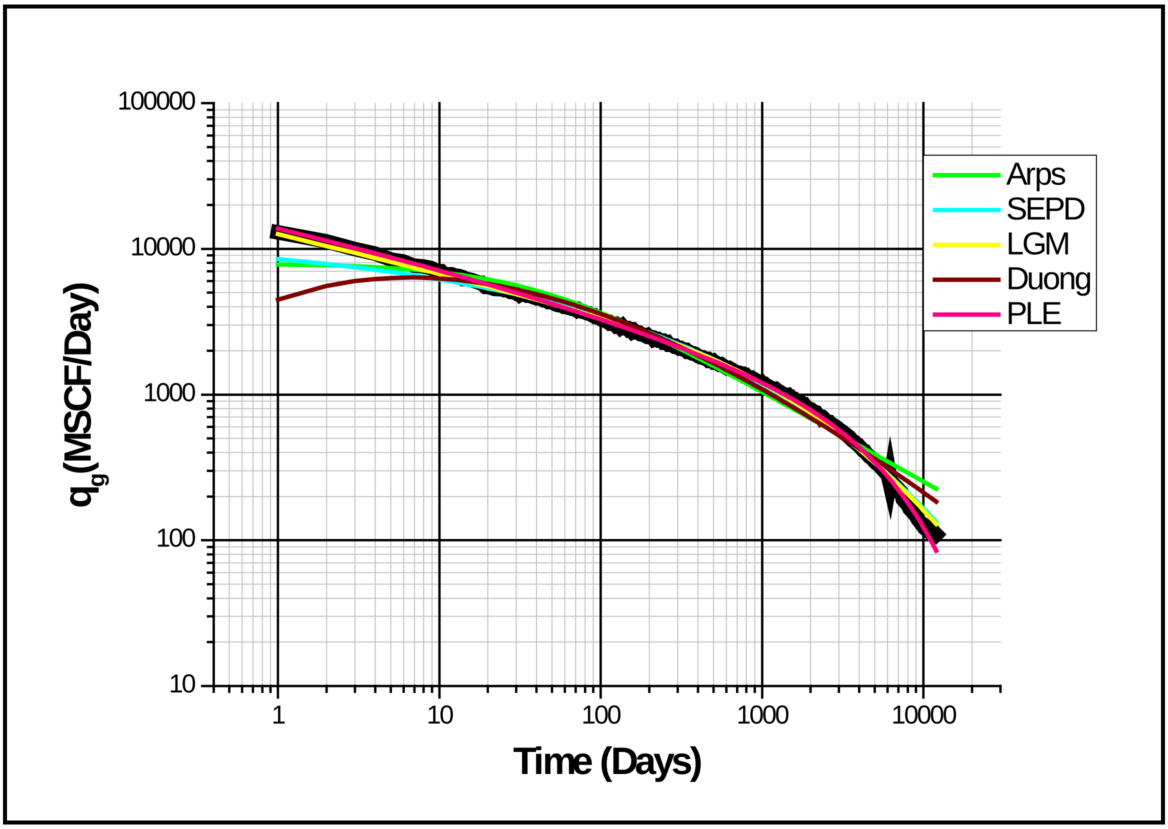

Figure 22 Prediction comparison of case 4 after 8000 days of production.

Field Case

Field Case is a Mexican field tight gas well that produced for about 44 years with a smooth performance given in Figure 23. The well behaviour stayed in linear flow for about 18 years (half slope in Figure 24) before the outer boundary felt such as case 2 in simulated data. A summary of reservoir fluid properties is shown in Table 2. and EUR is measures to be approximately 14 BSCF.

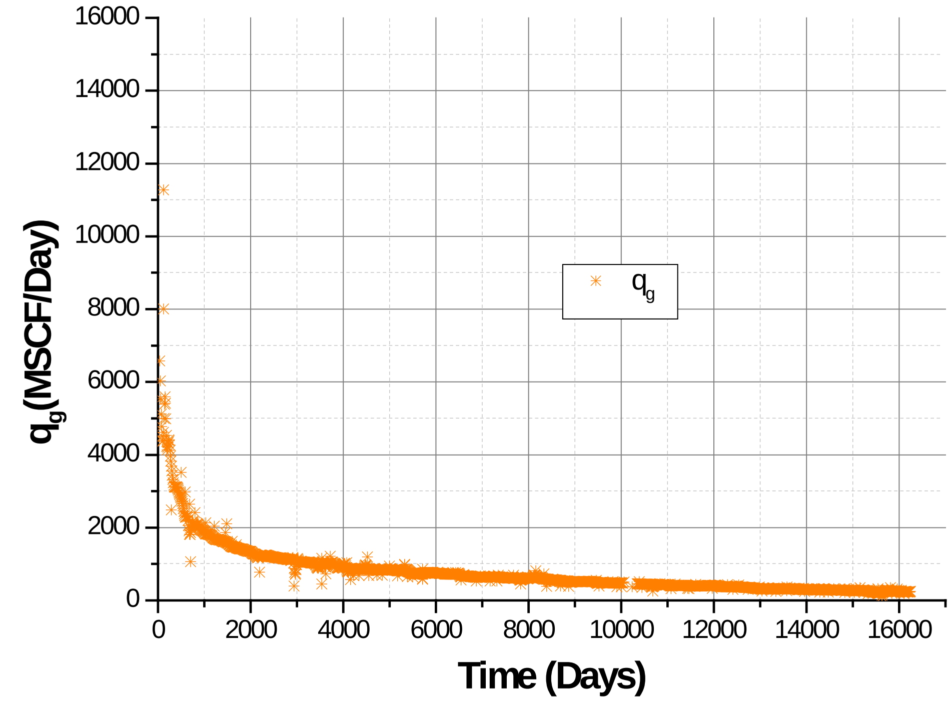

Figure 23 Decline of Mexican tight gas well of Field Case.

Table 2 Reservoir and Fluid data of Mexican tight gas well of Field Case.

Reservoir data			**Fluid data**		
Initial pressure, P_i	5463	Psia	Water compressibility, C_w	$4.1*10^{-6}$	1/psia
Bottom hole flowing pressure, P_{wf}	800	Psia	Gas gravity, γ_g	0.586	--
Initial Temperature, T	230	°F	Hydrogen sulphide, H_2S	0.02	Mole fraction
Porosity, ø	0.07	--	Carbon dioxide, CO_2	0.06	Mole fraction
Thickness, h	115	Ft.	Nitrogen, N_2	0.01	Mole fraction
Water saturation, S_w	0.12	--	Temperature @ s.c	60	°F
Formation compressibility, C_f	$4.22*10^{-6}$	1/psia	Pressure @ s.c.	14.65	psia

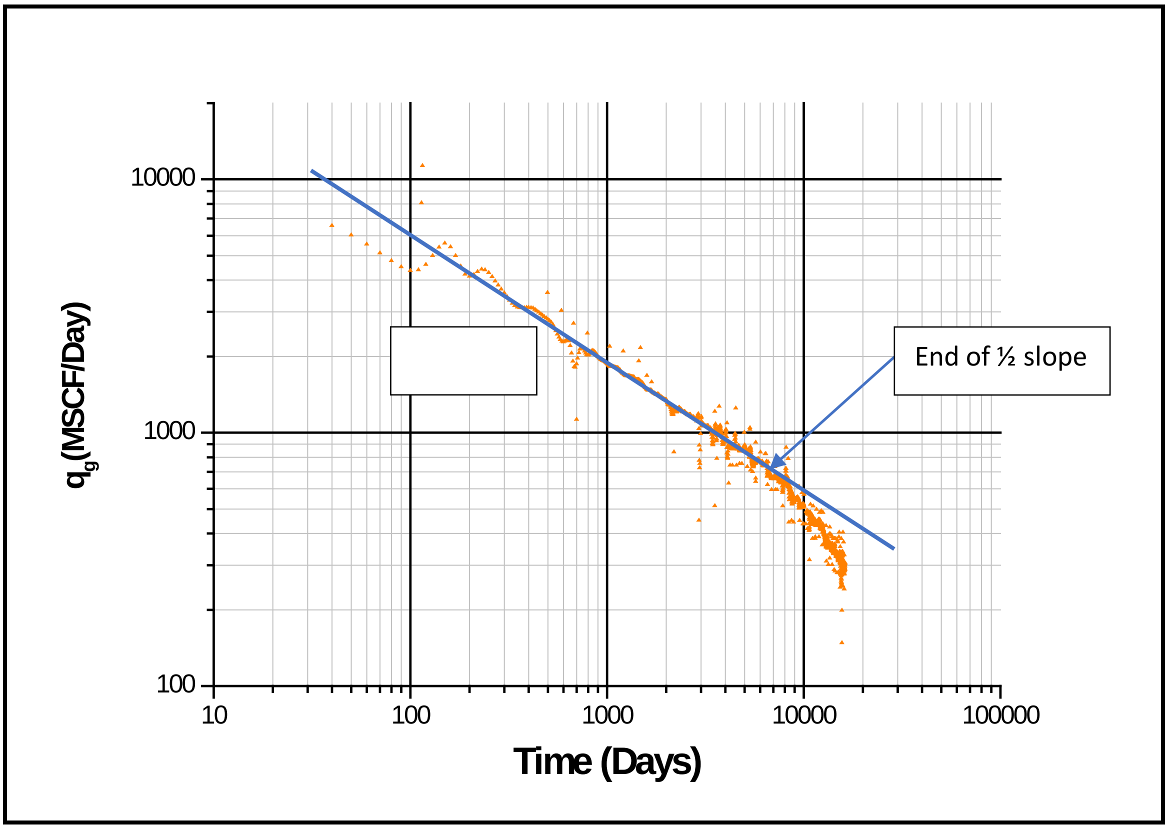

Figure 24 Log-Log plot of Production history to Field Case.

Arps Method

60% of the production data were used for matching (10,000 days) and **Figure**25 and **Figure** 26 shows the production match results before and after regression and results of regression is given in table 3.

Table 3 Comparison between assumed and adjusted parameters of Arps method for Field Case.

Parameter	Assumed Values	Adjusted Values
Di (day^{-1})	0.01	0.1176
q_i (MSCF/Day)	60000	30865
b	0.5	1.95

By regression we get adjusted values of Arps parameters, so we can now forecast the performance of the well and estimate EUR that equals to 14.9 BSCF as shown in Figure 27.

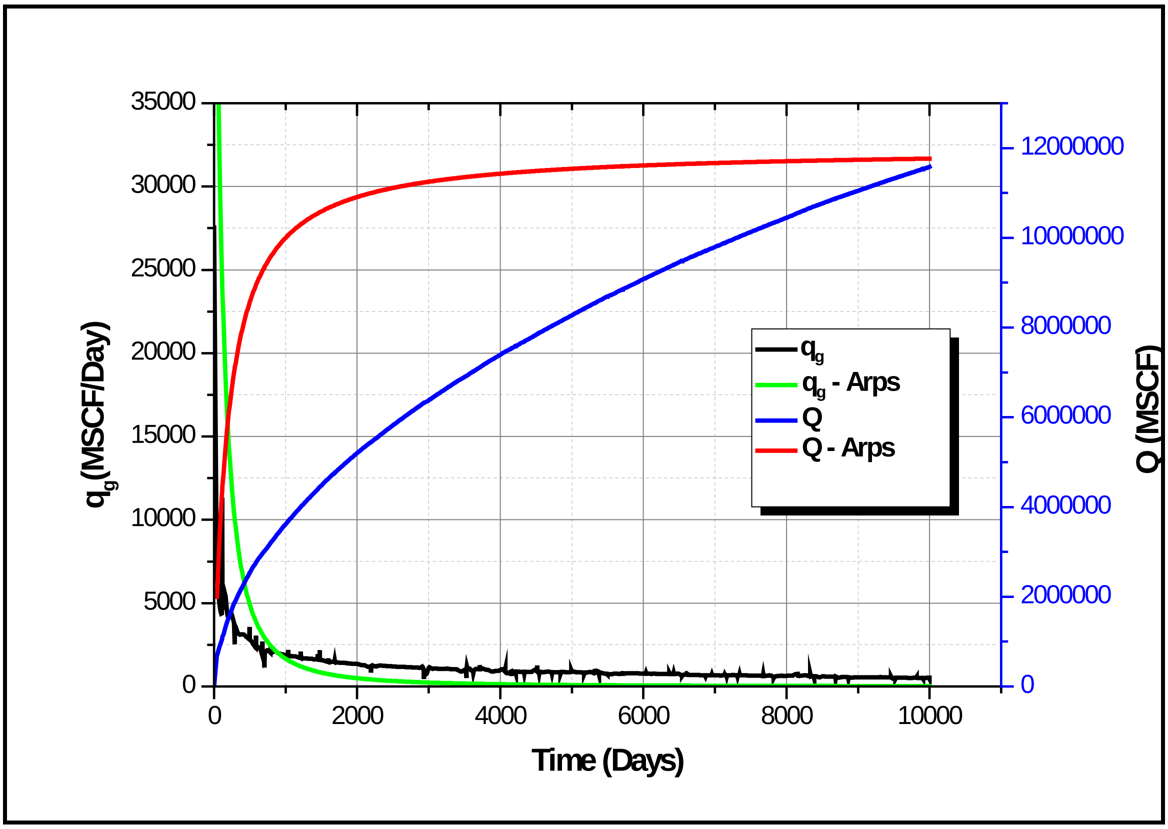

Figure25 Matching production data of Field Casebefore regression using Arps Method.

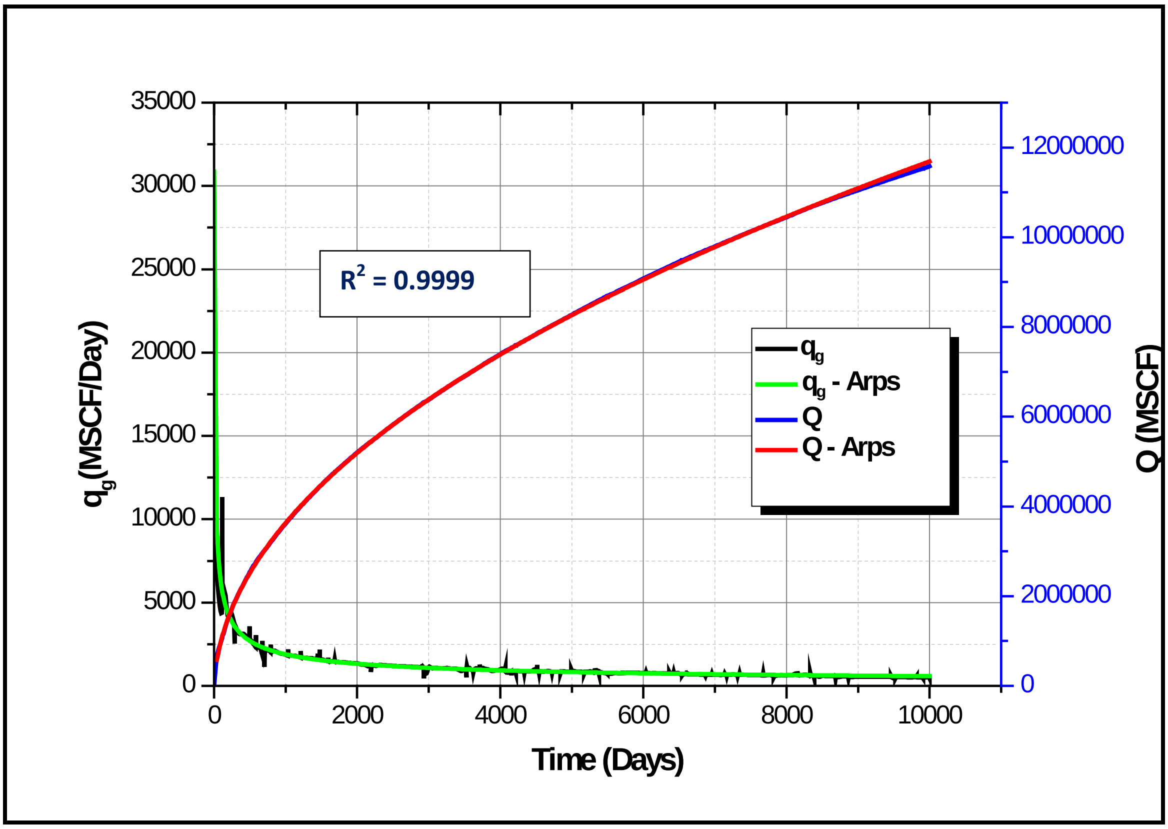

Figure 26 Matching production data of Field Caseafter regression using Arps Method.

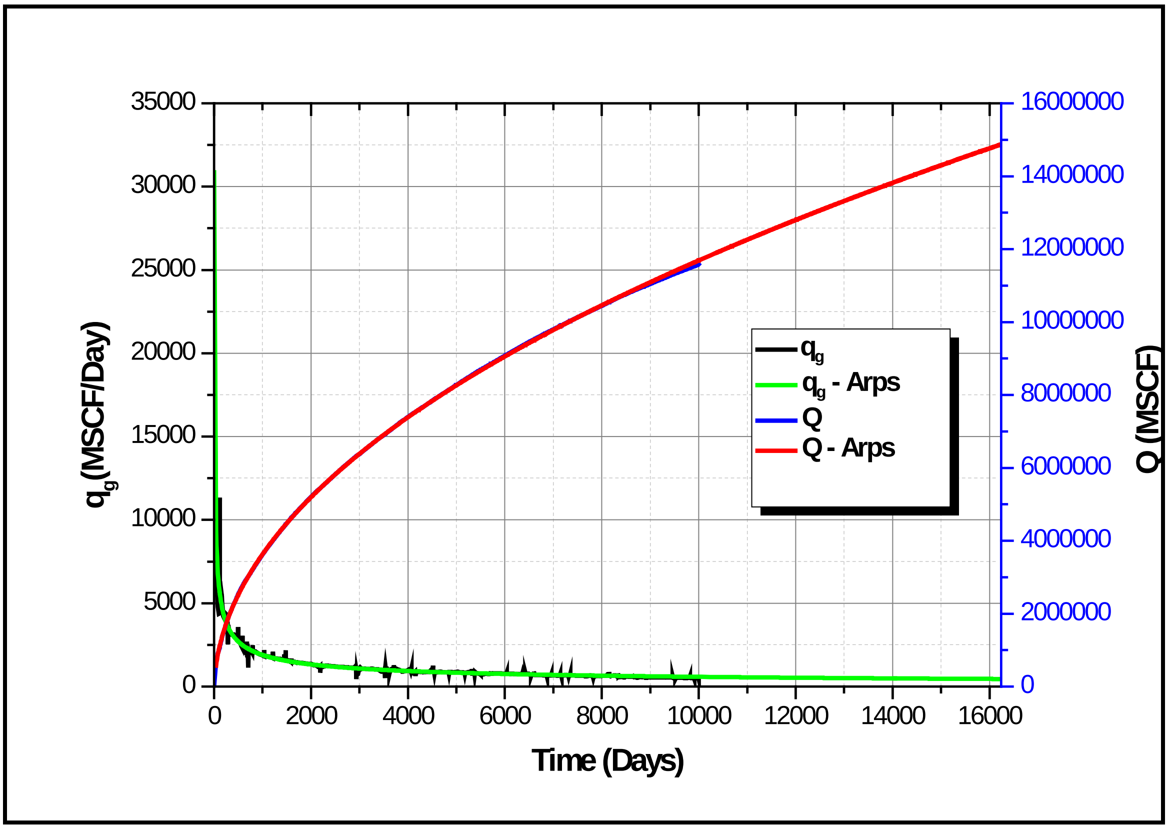

Figure 27 Prediction of production performance of Field Caseusing Arps Method.

SEPD

On 60% of the data (1000days). Results of adjusted parameters and prediction of production is shown in Table 4 and in Figure 28 and Figure 29.

Table 4 Comparison between assumed and adjusted parameters of SEPD method for Field Case.

Parameter	**Assumed Value**	**Adjusted Value**
q_i (MSCF/Day)	8068	8068
n	0.5	0.1973
τ	60	126

By regression we get adjusted values of SEPD parameters, so we can now forecast the performance of the well and estimate EUR that equals to 16.3 BSCF as shown in Figure 30.

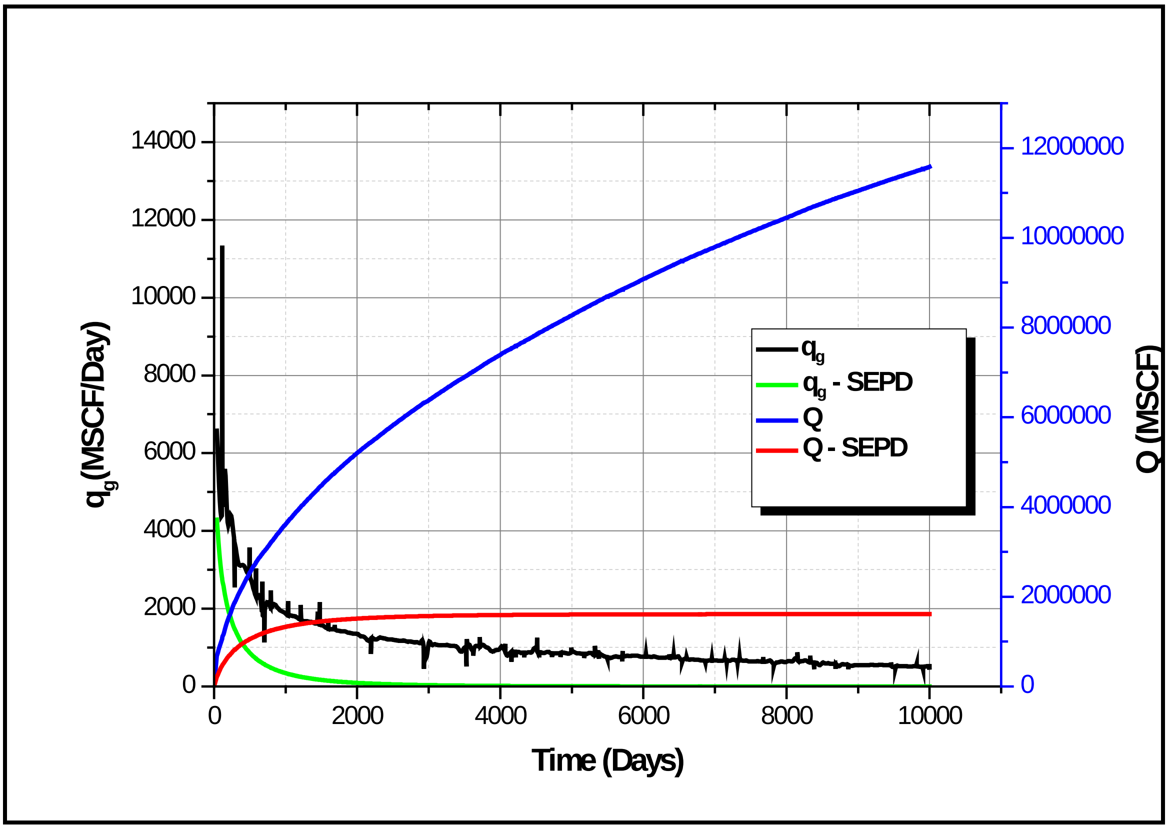

Figure 28 Matching production data of Field Casebefore regression using SEPD Method.

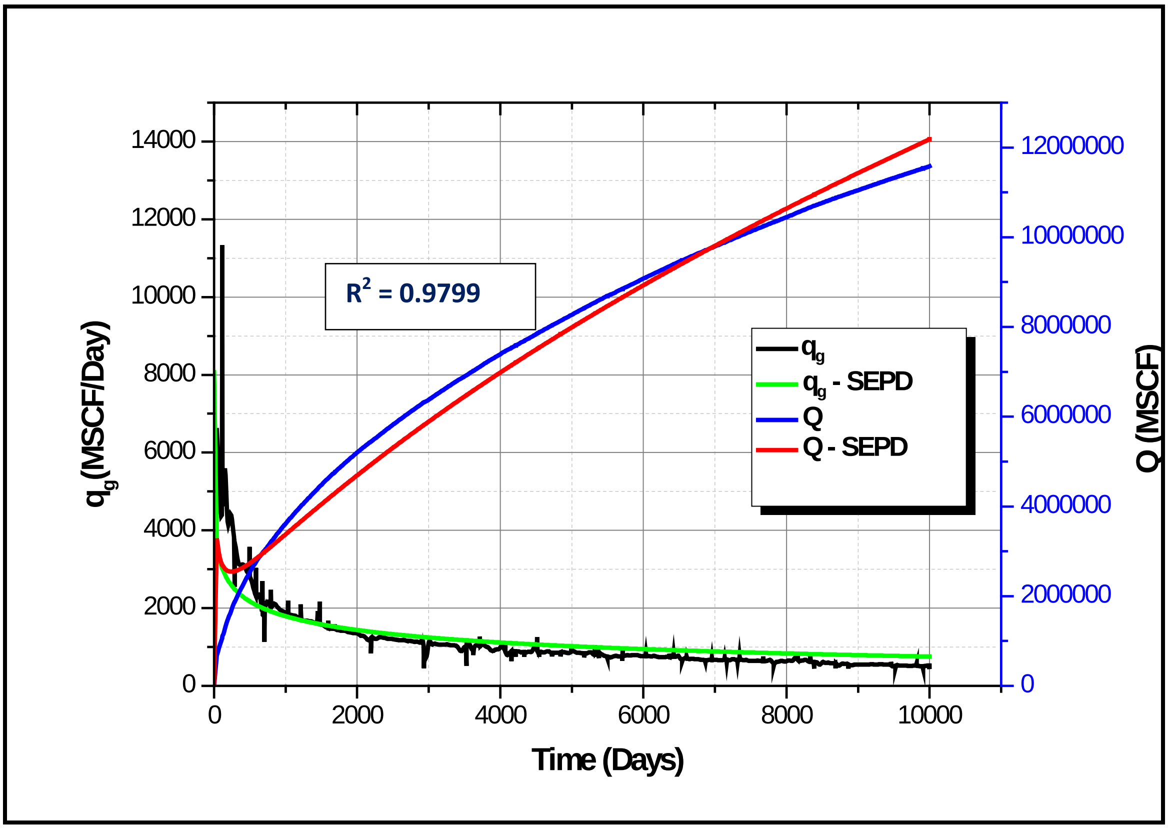

Figure 29 Matching production data of Field Caseafter regression using SEPD Method.

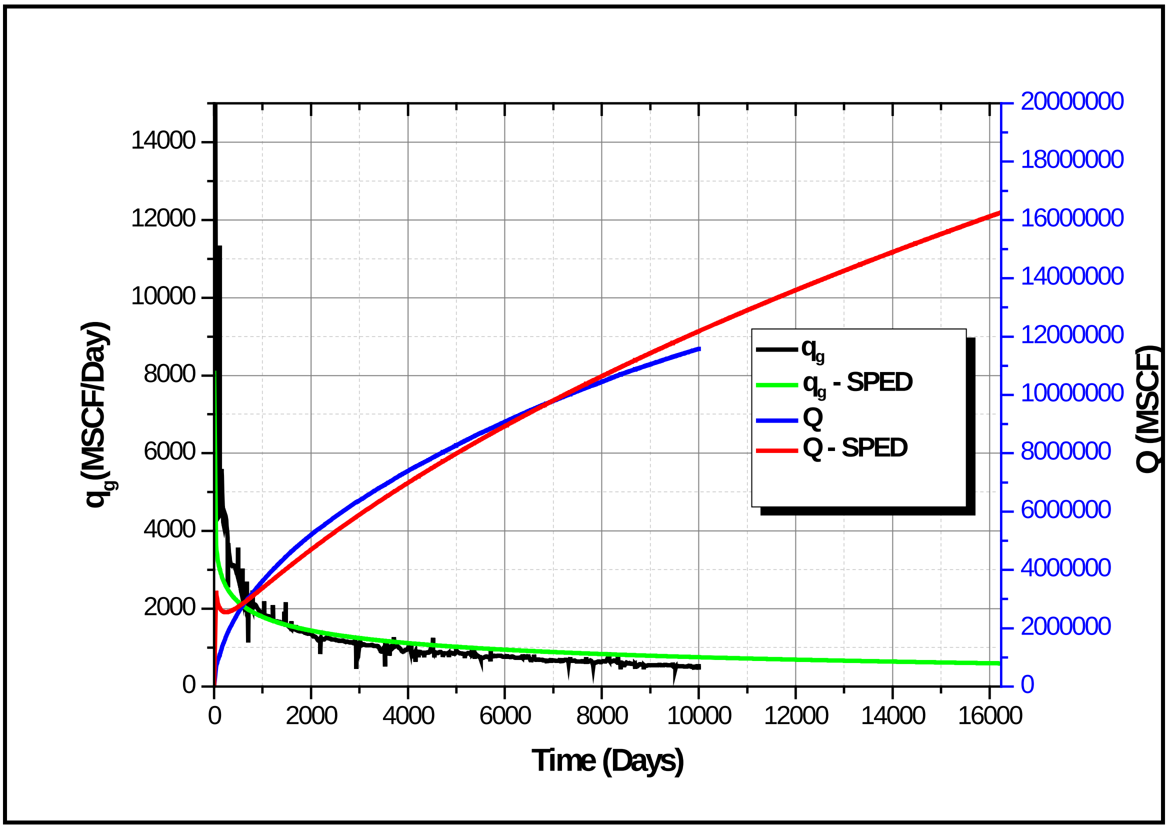

Figure 30 Prediction of production performance of Field Caseusing SEPD Method.

LGM

On 60% of the data (1000days). Results of adjusted parameters and prediction of production is shown in Table 5 and in Figure 31 and Figure 32.

By regression we get adjusted values of LGM parameters, so we can now forecast the performance of the well and estimate EUR that equals to 14.6 BSCF as shown in Figure 33.

Table 5 Comparison between assumed and adjusted parameters of LGM method for Field Case.

Parameter	**Assumed Value**	**Adjusted Value**
K	10,000,000	91,977,821
n	1.3	0.5483
a	400	1078.2

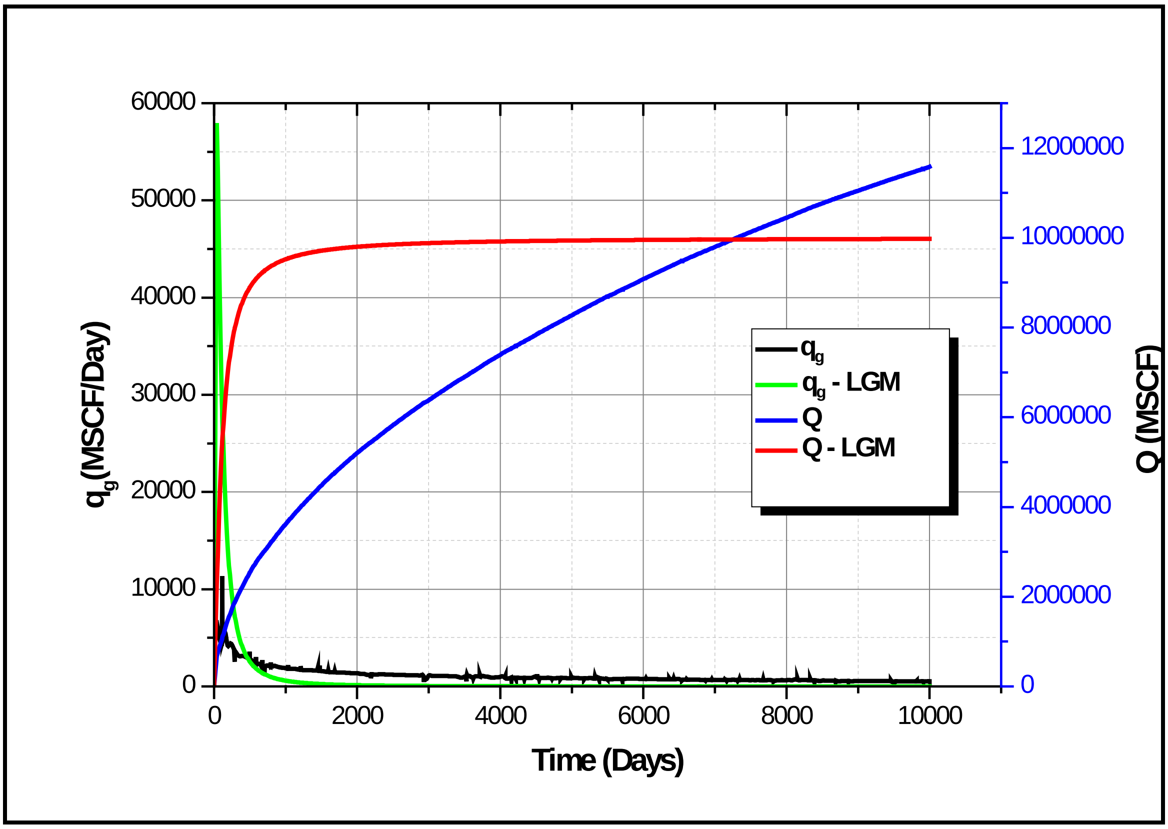

Figure 31 Matching production data of Field Case before regression using LGM Method.

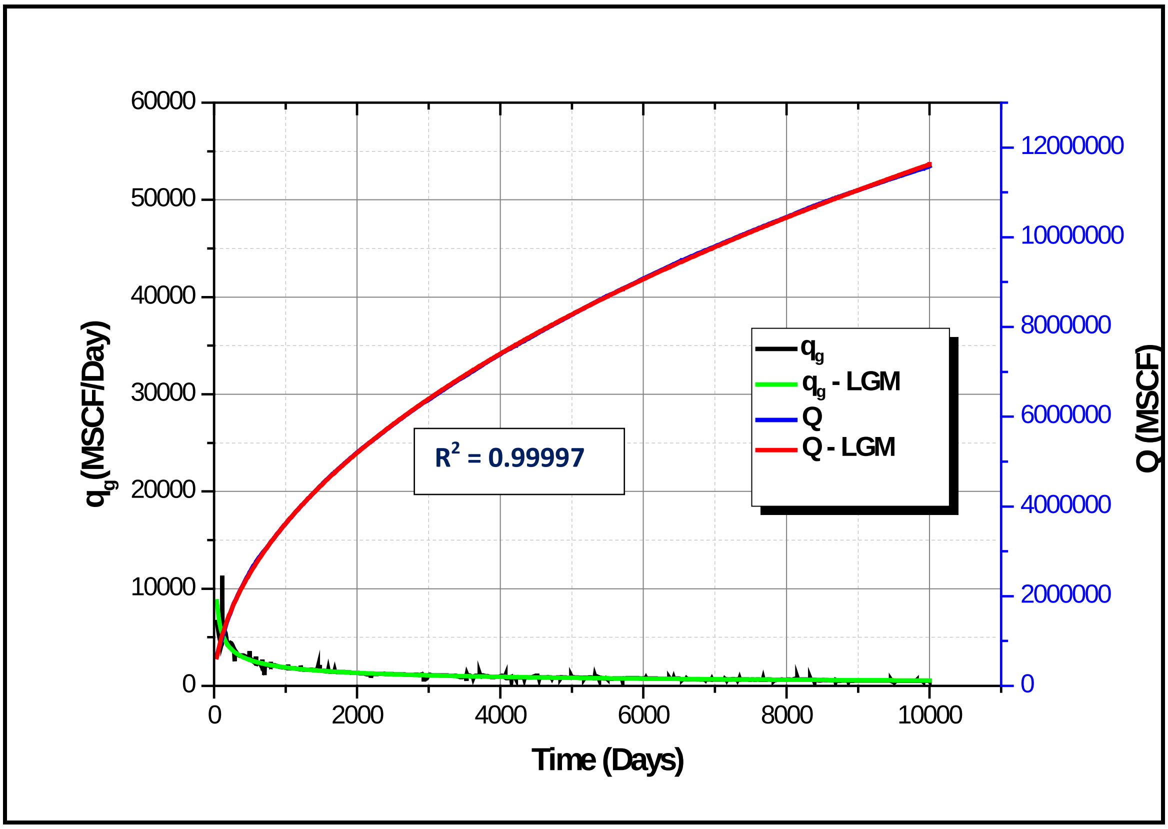

Figure 32 Matching production data of Field Case after regression using LGM Method.

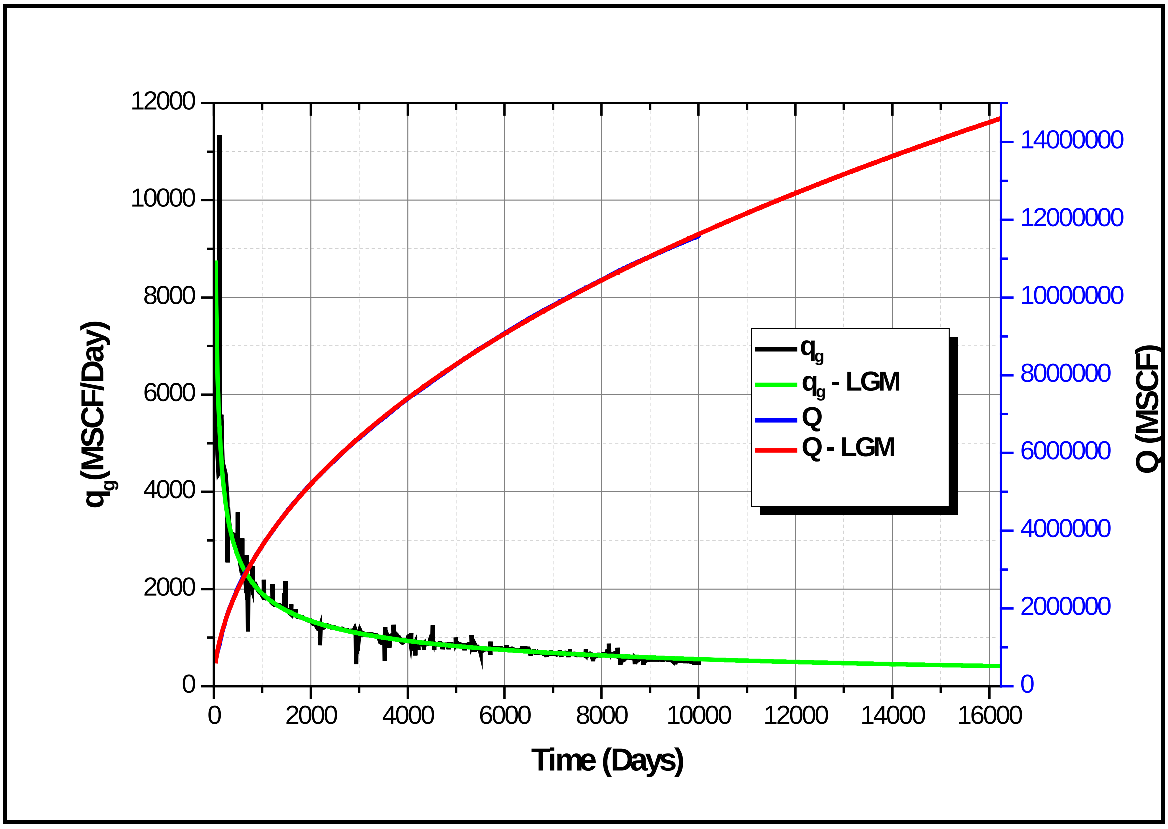

Figure 33 Prediction of production performance of Field Case using LGM Method.

Duong Method

On 60% of the data (1000days):

1- qg/Q vs. time was plotted on a log-log graph paper and a power law fit line was drawn to get an assumption for a and m as shown in Figure 34.
2- By assuming qi= 30,000 MSCF/Day, qg and Q were predicted as a function of time as shown in Figure 35.
3- a and mvalues adjustedusing regression and plot regressed curve as shown in Figure 36 and result of parameter after regression is given in Table 6.
4- Future production predicted and EURequals to 14.7 BSCF as shown in Figure 37.

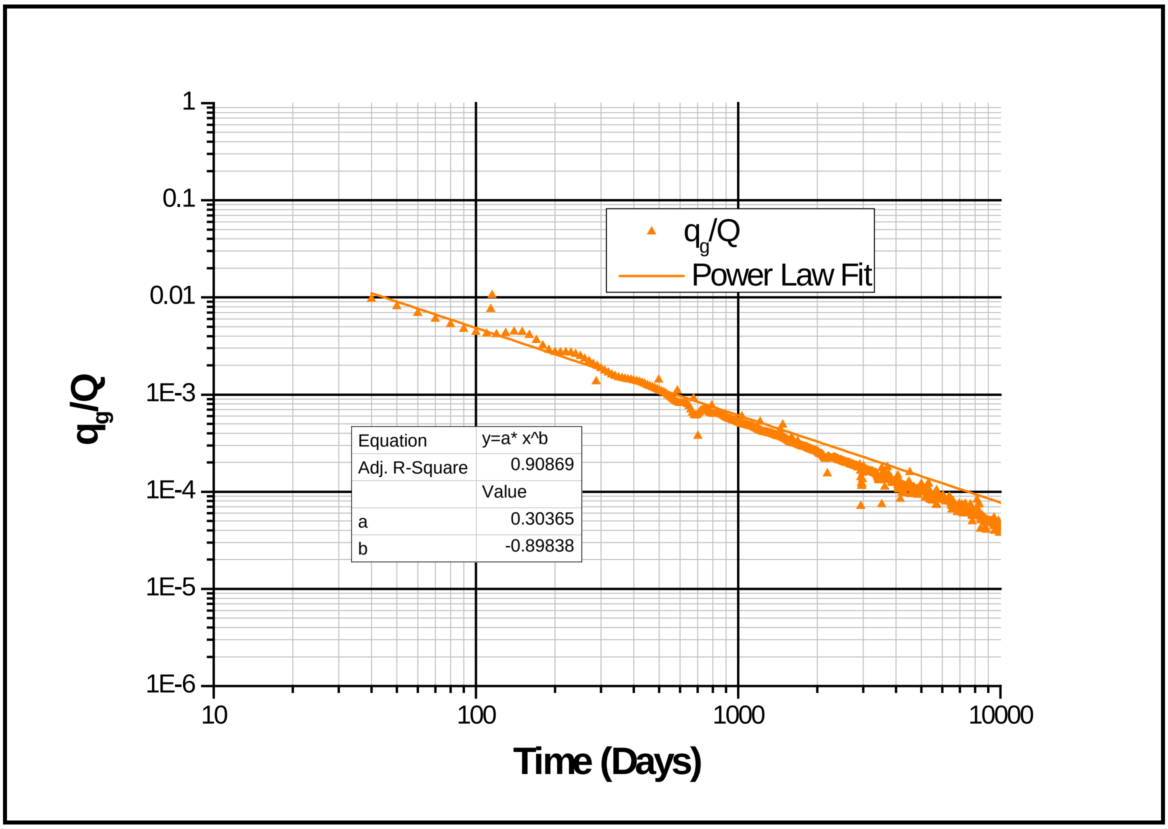

Figure 34 Duong's power law fit for field case.

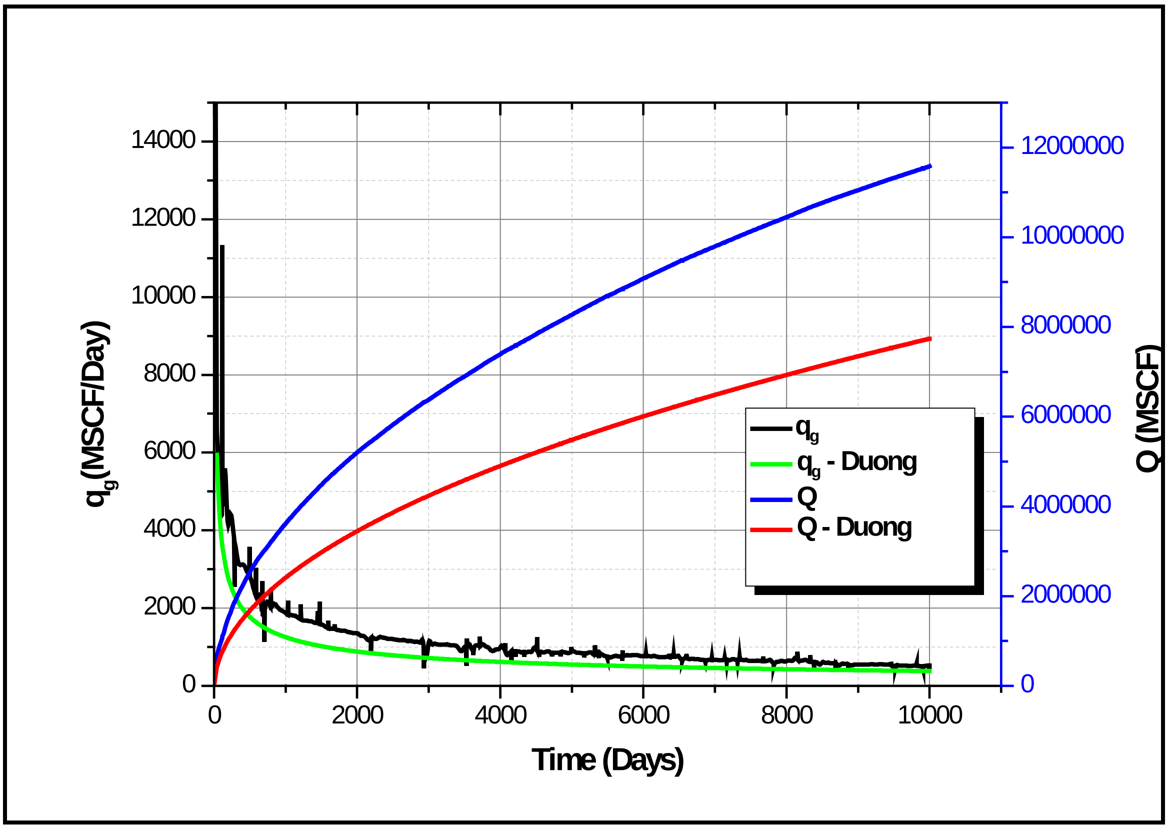

Figure 35 Matching production data of field Case before regression using Duong Method.

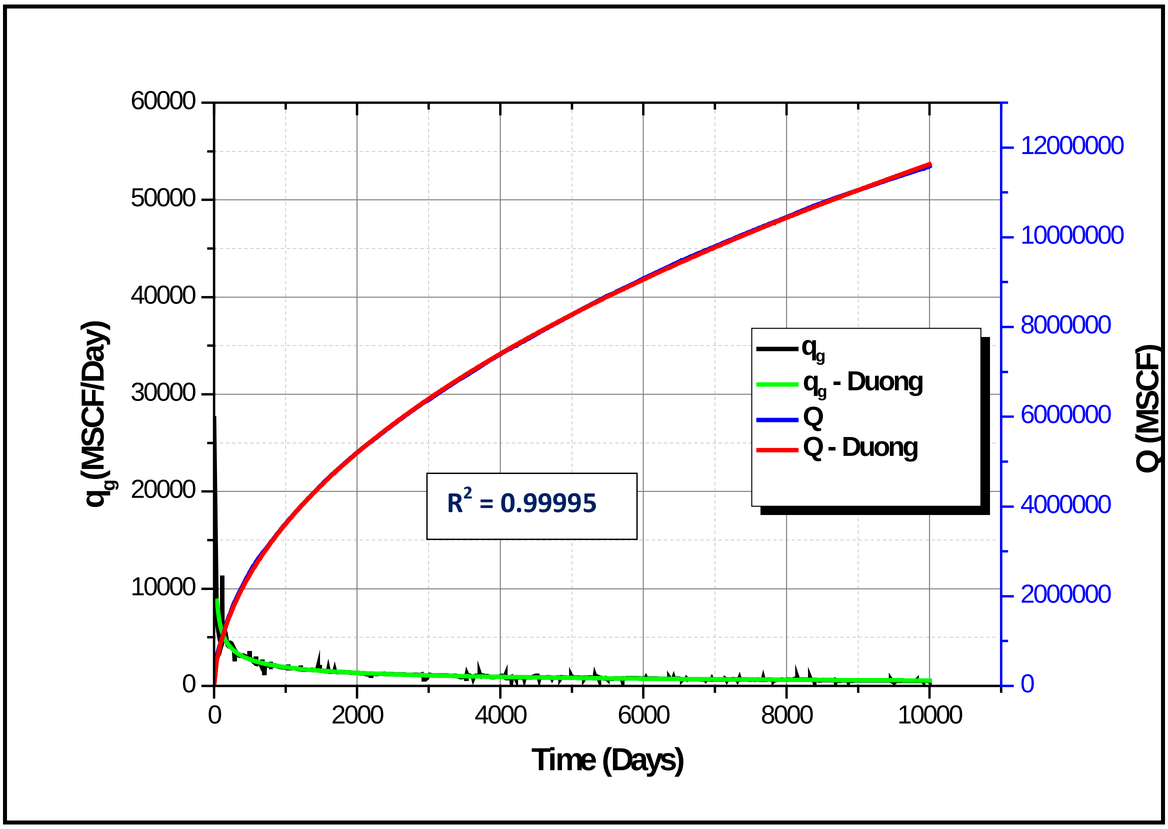

Figure 36 Matching production data of field Case after regression using Duong Method.

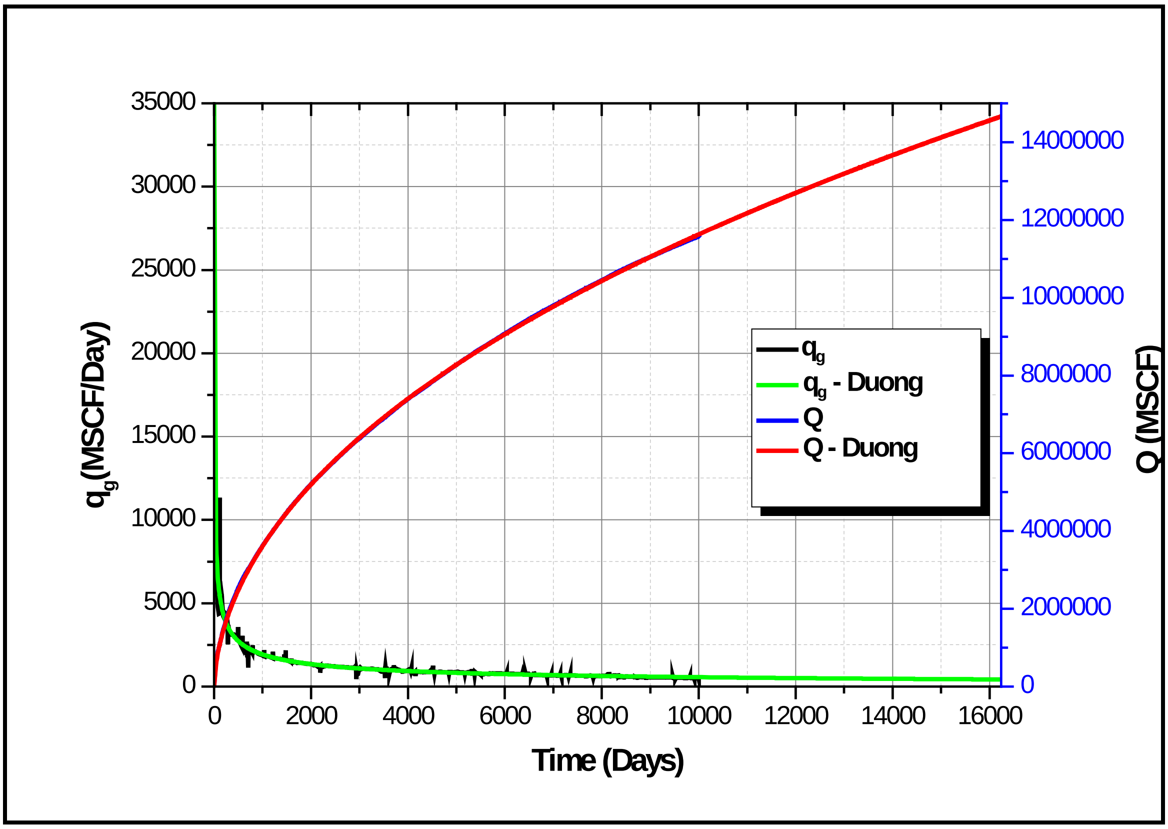

Figure 37 Prediction of production performance of field Case using Duong Method.

PLE

On 60% of the data (1000 days). Results of adjusted parameters and prediction of production is shown in Table 7 and in Figure 38 and Figure 39.

Table 7 Comparison between assumed and adjusted parameters of PLE method for field case.

Parameter	**Assumed Value**	**Adjusted Value**
q_i (MSCF/Day)	30,000	29590
D_∞	0.0001	0
D^	0.003	0.3561
n	0.8	0.2876

By regression we get adjusted values of LGM parameters, so we can now forecast the performance of the well and estimate EUR that equals to 11 BSCF as shown in Figure 40.

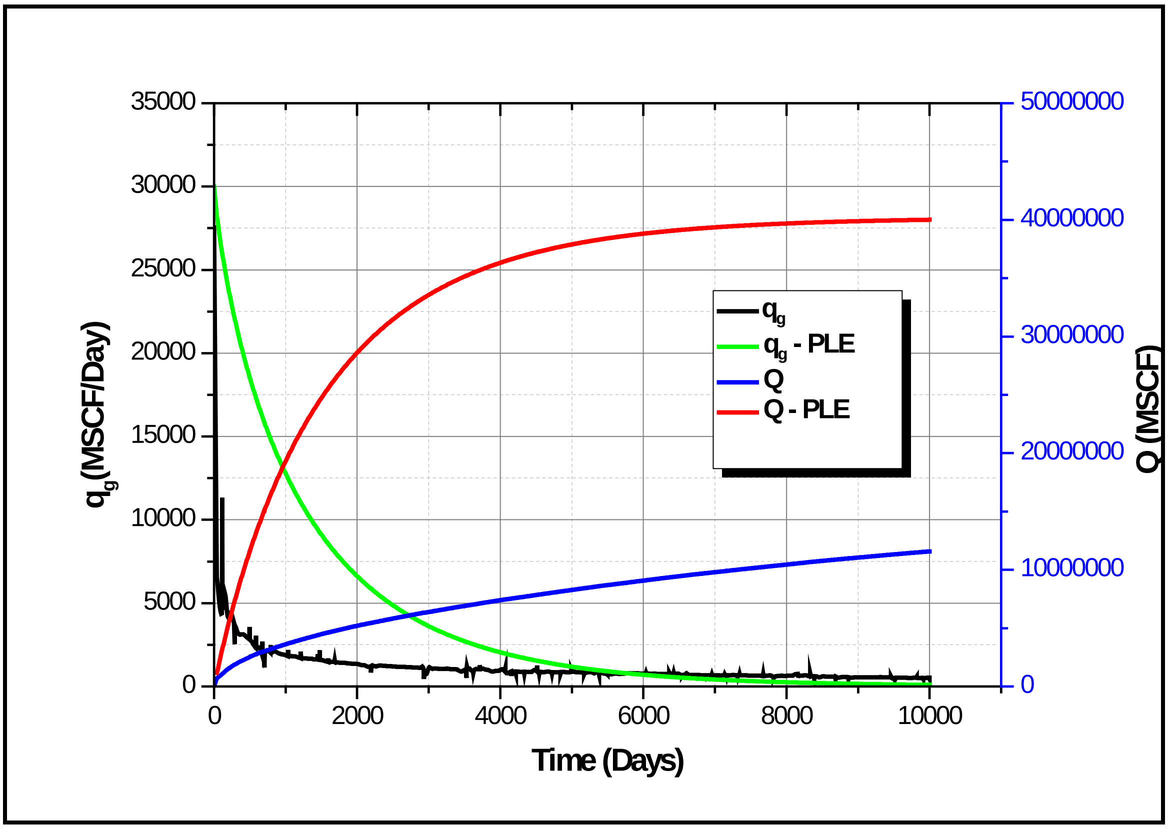

Figure 38 Matching production data of field case before regression using PLE Method.

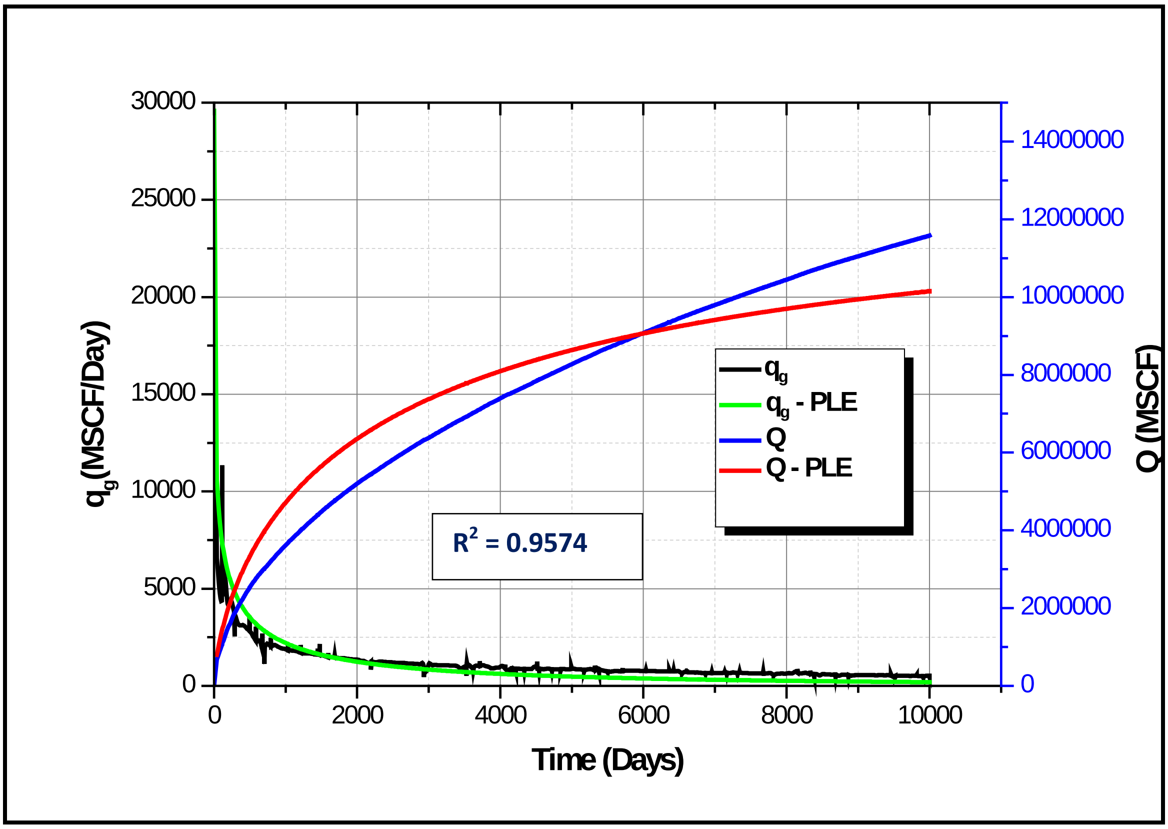

Figure 39 Matching production data of field Case after regression using PLE Method.

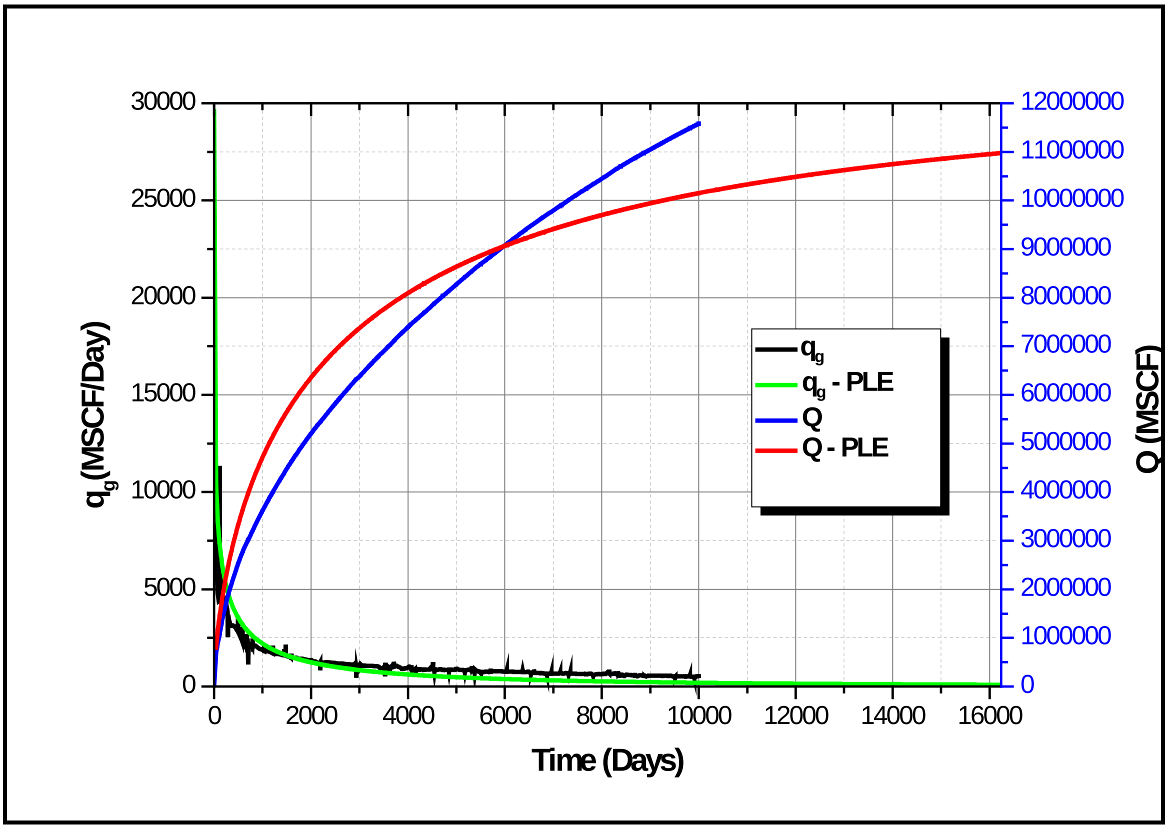

Figure 40 Prediction of production performance of field Case using PLE Method.

Results and Discussion

As mentioned before DCA is the one of the easiest and simplest methods that can be used to predict performance of a well.Building reservoir model requires drilling test well and running well logs whichare very time consuming and need great budget that most companies cannot afford.

As production from unconventional reservoirs increases, especially shale gases, many DCA models have been developed to models these reservoirs starting by modifying Arps model to a completely new empirical models that are completely different from it, have their own parameters and assumptions. Manyof these models nowadays become available for practice in commercial DCA software.

The main reason to get modern DCA models other than Arps than that can model unconventional reservoirs is that they flow for a very long period under transient flow and may not reach BDF through their production life. In our cases that represent flow regimes of a typically unconventional reservoir simulated to determine the best models/s for each case:

- Case 1, Linear flow: if the well is flowing in a linear flow and expected to continue till abandonment, the most accurate models to predict and estimate EUR are Arps, PLE and LGM models. Duong model can be used and get accurate results if $q\infty$ constrained to zero in regression.

- Case 3, Bilinear-linear flow: if the well is expected to flow at linear flow till abandonment but is preceded by bilinear flow, the best models to predict and estimate EUR are SEPD, Duong and PLE.
- Case 2&4, as BDF is detected after linear flow as in case 2 or linear flow preceded by Bilinear flow as in case 4, good prediction cannot be observed. BDF is observed in the production history to get a reliable prediction and EUR.

Table 8 Summer up best applicable DCA models based on type of flow regime observed in the simulated well production history.

Table 8 Summary of best applicable DCA models for each flow regimes.

Model	**Linear Flow**	**Bilinear - linear Flow**	**Linear-BDF**	**Bilinear – Linear - BDF**
Arps	✓	☒	☒	☒
SEPD	☒	✓	☒	☒
LGM	✓	☒	☒	✓
Duong	✓ (With constrains)	✓	☒	☒
PLE	✓	✓	✓	✓

For Field case thatwas a well that flowing at linear flow for about 18 years and then flow under BDF as in case 2 of simulator. The EUR is estimated to be 14 BSCF. Result of EUR estimated using models is given in **table 9.**

Table 9 EUR results of DCA models of field case.

	Arps	**SEPD**	**LGM**	**Duong**	**PLE**
EUR (BSCF)	14.9	16.3	14.6	14.7	11

From these EURs we get that the best model that get closely to the correct EUR is LGM model, which is contrary to the expected as we get from simulated data that PLE best predict BDF with transient flow; that is because PLE model regression was constrained by q_i as if I let the model without constrains will lead to an extremely high values that may reach billions of MSCF/Day to get fit.

For unconventional reservoirs predicting well performance using DCA is still a point that needs lots of work and there is no one model can be used as in Arps model for conventional reservoirs and for the prediction it is needed to apply all available models to get at least the range of EUR.

Conclusion

- Arps' equation whether used modified to get b within its range or used as it is without modification using b value of 2 or 4 to be able to fit bilinear and linear straight-line region on the log-log plot of q vs. time it cannot model correctly.
- PLE method is the only one that can model both transient and BDF decline but it is very time consuming and may result in nonunique solutions as it contains 4 unknowns that gives 4 degrees of freedom.
- PLE model gives a great underestimation of EUR and may be misleading.
- SEPD model is difficult to shape straight-line in log-log plot because of the formula of the equation, so it gets a high over estimation of EUR
- LGM is the easiest and simplest method to use.
- If BDF is expected to occur, no decline curve model can predict performance and estimate EUR unless BDF is observed in the production history.
- The only method that can model both transient (linear & bilinear) flow and BDF is the PLE method and in some special cases (I believe it is just a coincidence) is the LGM models.
- The main disadvantage of all used DCA models that they are totally empirical and without any physical basis and all parameters are calculated using regression to match production history and then predict performance.

References

1. Ahmed, T., *Chapter 18 - Modern Decline Curve Analysis*, in *Reservoir Engineering Handbook (Fifth Edition)*, T. Ahmed, Editor. 2019, Gulf Professional Publishing. p. 1389-1461.

2. Arps, J.J., *Analysis of Decline Curves.* Transactions of the AIME, 1945. **160**(01): p. 228-247.

3. Caineng, Z., et al., *Concepts, characteristics, potential and technology of unconventional hydrocarbons: On unconventional petroleum geology.* Petroleum Exploration and Development, 2013. **40**(4): p. 413-428.

4. Clark, A.J., L.W. Lake, and T.W. Patzek. *Production Forecasting with Logistic Growth Models*. in *SPE Annual Technical Conference and Exhibition*. 2011.

5. Duong, A.N. *An Unconventional Rate Decline Approach for Tight and Fracture-Dominated Gas Wells*. in *Canadian Unconventional Resources and International Petroleum Conference*. 2010.

6. Duong, A.N., *Rate-Decline Analysis for Fracture-Dominated Shale Reservoirs.* SPE Reservoir Evaluation & Engineering, 2011. **14**(03): p. 377-387.

7. Halliburton. *Unconventional Reservoir Wells*. 2021; Available from: https://www.halliburton.com/en-US/ps/cementing/cementing-solutions/unconventional-reservoir-wells/default.html.

8. Ilk, D., et al. *Exponential vs. Hyperbolic Decline in Tight Gas Sands: Understanding the Origin and Implications for Reserve Estimates Using Arps' Decline Curves*. in *SPE Annual Technical Conference and Exhibition*. 2008.

9. Joseph H. Frantz, J. and S. Valerie Jochen. *Shale Gas*. 2005; Available from: http://large.stanford.edu/courses/2010/ph240/alnoaimi2/docs/shale_gas_solution_05of299.pdf.
10. Kanfar, M.S., *Comparison of Emperical Decline Curve Analysis for Shale Wells*. 2013.
11. Spivey, J.P., et al. *Applications of the Transient Hyperbolic Exponent*. in *SPE Rocky Mountain Petroleum Technology Conference*. 2001.
12. Valko, P.P. *Assigning value to stimulation in the Barnett Shale: a simultaneous analysis of 7000 plus production hystories and well completion records*. in *SPE Hydraulic Fracturing Technology Conference*. 2009.