COMPARISON OF VARIOUS DETERMINISTIC FORECASTING TECHNIQUES IN SHALE GAS RESERVOIRS WITH EMPHASIS ON THE DUONG METHOD

A Thesis

by

KRUNAL JAYKANT JOSHI

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

August 2012

Major Subject: Petroleum Engineering

Comparison of Various Deterministic Forecasting Techniques in Shale Gas Reservoirs

With Emphasis on the Duong Method

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Approved by:

Co-Chairs of Committee, John Lee
Duane McVay
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ABSTRACT

Comparison of Various Deterministic Forecasting Techniques in Shale Gas Reservoirs With Emphasis on the Duong Method. (August 2012)

Krunal Jaykant Joshi, B.S., Texas A&M University at College Station

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Dr. Duane McVay

There is a huge demand in the industry to forecast production in shale gas reservoirs accurately. There are many methods including volumetric, Decline Curve Analysis (DCA), analytical simulation and numerical simulation. Each one of these methods has its advantages and disadvantages, but only the DCA technique can use readily available production data to forecast rapidly and to an extent accurately.

The DCA methods in use in the industry such as the Arps method had originally been developed for Boundary dominated flow (BDF) wells but it has been observed in shale reservoirs the predominant flow regime is transient flow. Therefore it was imperative to develop newer models to match and forecast transient flow regimes. The SEDM/SEPD, the Duong model and the Arps with a minimum decline rate are models that have the ability to match and forecast wells with transient flow followed by boundary flow.

I have revised the Duong model to forecast better than the original model. I have also observed a certain variation of the Duong model proves to be a robust model for most of the well cases and flow regimes. The modified Duong has been shown to work best compared to other deterministic models in most cases. For grouped datasets the SPED & Duong models forecast accurately while the Modified Arps does a poor job.

DEDICATION

I want to dedicate this to my gurus Dr.John Lee & my parents. I also want to dedicate this to my younger brother. To my friends in the PETE department I also thank you for making my time at A&M more enjoyable & less stressful.

Gig'em

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I would like to acknowledge Fekete for use of their well test software. I would also want to acknowledge Raul Gonzales and Xinglai Gong for use of their Probabilistic Decline Curve Analysis (PDCA) package.

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CHAPTER I

INTRODUCTION AND LITERATURE REVIEW

The stock of every oil and gas company is dependent on its petroleum reserves. Reporting reserves is important not only for the companies but also the investors who mainly invest based on the reserves of the company. Up till recently, before the renewed interest in unconventional reservoirs, reporting and calculating of reserves has been a predominantly deterministic process. With the advent of sophisticated technologies, exploration in unconventional reservoirs has become economical to drill and produce. But the industry's lack of knowledge of the physics and flow processes of these resource plays limits the ability to model the production with confidence thus introducing major uncertainties (Lee and Sidle 2010). The uncertainty in shale and tight gas reserves, unlike conventional reserves, has significant implications at both the micro and macro levels (Strickland et al. 2011).

Over the past decade advances in technology has enabled the industry to explore rocks that were once thought to be impermeable and uneconomical.

This thesis follows the style of *Society of Petroleum Engineers (SPE) Economics & Management Journal.*

Three of the biggest advances in drilling and fracturing technology that have enabled commercial production from ultra-low permeability reservoirs

are long horizontal laterals , multiple transverse fractures and new surveillance techniques like micro seismic (Ambrose et al. 2011).Over the past few years, a renewed interest in low permeability reservoirs, especially shale gas reservoirs has brought about an increase in forecasting methods to predict future production and EUR. Some of the analytical models proposed are the dual porosity model (Bello and Wattenbarger 2008) the tri-linear flow model (Ozkan et al. 2009) and the composite model(Thompson et al. 2011). The disadvantages of using analytical models are the assumptions made and the accuracy of input data required to get precise production that models the field data. The overtly simplification of the fracture network can also be a cause for concern especially for the complex stimulated reservoir volume (SRV) structures in shale reservoirs. Empirical models are the most widely used forecasting method in the industry despite advances in other estimating techniques (Ambrose et al. 2011).The most widely used empirical method is the Arps decline curve (Arps 1945), but is does have its deficiencies when used for ultra-low permeability reservoirs. The Arps model was originally developed for Boundary dominated flow (BDF) wells but the flow regime dominant in shale reservoirs is transient flow. Therefore the Arps model is being incorrectly applied for shale gas forecasting. Three recent empirical models that have been developed are the power law exponential(Ilk et al. 2008), the stretched exponential (Valko and Lee 2010)and the Duong linear flow model (Duong 2010). There have been some empirical models developed that are offshoots of the Arps decline curves like the terminal decline method (Long and Davis 1988) and the linear flow/BDF model (Nobakht et al. 2010). The Nobakht model is a promising model but like the Bello and Wattenbarger model it requires a lot of input properties like the permeability, fracture half length, compressibility and porosity. The uncertainty associated with these inputs is high therefore these analytical models have a high degree of uncertainty associated with them.

Even with these advances in forecasting techniques, estimating reserves in current resource plays is difficult, since most of the methodologies and their results include significant uncertainties(Lee and Sidle 2010). Therefore the main objective of this thesis would be to characterize the uncertainty in the forecasts of empirical models and determine a model that could forecast shale gas production on a consistent basis.

CHAPTER II

APPROACH AND PLAN

2.1 Single well vs. grouped dataset

Single well analysis is widely used to perform decline curve analysis but in the case of shale and tight gas wells where a large number of wells are drilled to extract petroleum, single well analysis could prove too to be time consuming. Another disadvantage of single well analysis in shale gas reservoirs that is been observed is the variation in production data occurring due to operational reasons. Compared to single well analysis, a grouped data forecast statistically nullifies the effect of these stray operational occurrences. Since a grouped data set is a summation of normalized production rates a great deal of time is saved compared to a single well analysis. The grouped data set "offers statistically more consistent reserve estimates and also provides a potential well monitoring tool." (Valko and Lee 2010). Laustan, 1996 clearly indicates instances when either single well or grouped data analysis would prove faulty. This does not mean single well analysis is not practical. For companies with a low well count in a certain field, single well analysis would be the only way forward. An in-depth analysis of forecasts for single wells and grouped wells is provided in subsequent chapters. Care should be taken, especially for shale and tight gas reservoirs, that when single well analysis is performed, operating conditions should be considered when curve fitting to obtain accurate results. Another point that needs to be looked at is when performing grouped well analysis attention must be given to the well and rock properties. Wells must be grouped based on type of well, vertical or horizontal, completion technique and the similarity of the formation. An in depth analysis of the geology of the formation could be performed, including analyzing WOR maps, logs, cores, net pay maps etc. But as a reasonable assumption I have grouped data based on counties and the type of well (Horizontal fractured wells), with a good amount of accuracy.

To further validate the analysis performed in this thesis, monthly field production data was obtained using Drilling ∞o. The two shale plays on which the study is performed on are the Barnett and Fayetteville shale. The Barnett shale counties used in this study are the Denton, Wise, Tarrant and Johnson counties which are the core counties of this play. In the Fayetteville shale the Van Buren and Conway county were looked at. In the course of the study around 1500+ wells were analyzed and a random selection of 250 wells were selected as the field dataset used frequently below to compare various forecasting techniques and its abilities to match and forecast field production data accurately. Since shale plays are some of the newer frontier reservoirs, there is a lack of long term field production data to match and forecast empirical models accurately on a long term basis. To compensate for the lack of long term field data, multiple simulations were performed to recreate production in shale plays. An analytical simulation software, Fekete WellTest, was used to simulate production data up to 30 years. The two shale plays that are simulated using this software are the Barnett shale and the Marcellus shale. Reservoir and completion properties used as input for the software are consistent with the properties present in various SPE papers. For the Barnett shale reservoir and completion properties were obtained from SPE papers

133874(Chong et al. 2010), 146876(Cipolla et al. 2011), 144357(Strickland et al. 2011), 96917(Frantz et al. 2005), 125530(Cipolla et al. 2010) and147603(Ehlig-Economides and Economides 2011) while for the Marcellus shale the input properties for the simulator were obtained from SPE papers 133874(Chong et al. 2010), 125530(Cipolla et al. 2010), 144436 (Thompson et al. 2011) and 147603(Ehlig-Economides and Economides 2011).To simulate the alteration of the effective permeability in the SRV a composite model with a horizontal well and multiple fracture stages were used to simulate a hydraulically fractured horizontal shale well. A pictorial of the model will be shown in the chapter where various empirical models are matched to the simulated data.

25 simulations each were performed for the Barnett and Marcellus shale. For most of the simulations the completion properties like fracture stages, fracture length and fracture conductivity were changed in line with the variations presented in the previously mentioned SPE papers. The only reservoir property that was altered was the Stimulated Reservoir Volume (SRV) permeability. Since it is impossible to simulate the altered and complex fracture network in the SRV using an analytical model, an approximation to this was made by changing the permeability in the SRV region. This altered permeability is directly proportional to the intensity of the fracture treatment. The variability of the SRV permeability was also based in the aforementioned SPE papers used to obtain the reservoir and completion properties. An assumption is made that the simulations ran are simplified approximations to long term production data & in no way exactly determine long term production in a shale gas well.

2.2 Flow regimes

Unlike conventional wells, multi staged fractured horizontal wells see multiple flow regimes over the period of the life of the well. There might be some flow regimes that dominate the life of the wells like the fracture linear flow regime, but with the advent of newer and more sophisticated fracturing techniques, regimes like fracture boundary flow are being observed more often. **Figure 1** depicts the different flow regimes in a typical multi staged fractured horizontal well in the Marcellus shale. The below figure was created using the Fekete Well test software & input properties obtained from previously aforementioned papers. The flow regime that is not shown in **Figure 1** but is observed in low conductivity hydraulically fractured reservoirs is the bilinear flow regime. This flow regime is observed in a well in the Wise county, Barnett shale **(Figure 2)**. (Wattenbarger et al. 1998) stated that linear flow can be detected using a negative half slope line and bi-linear flow using a negative quarter slope line on a log-log plot of flow rate vs. time.

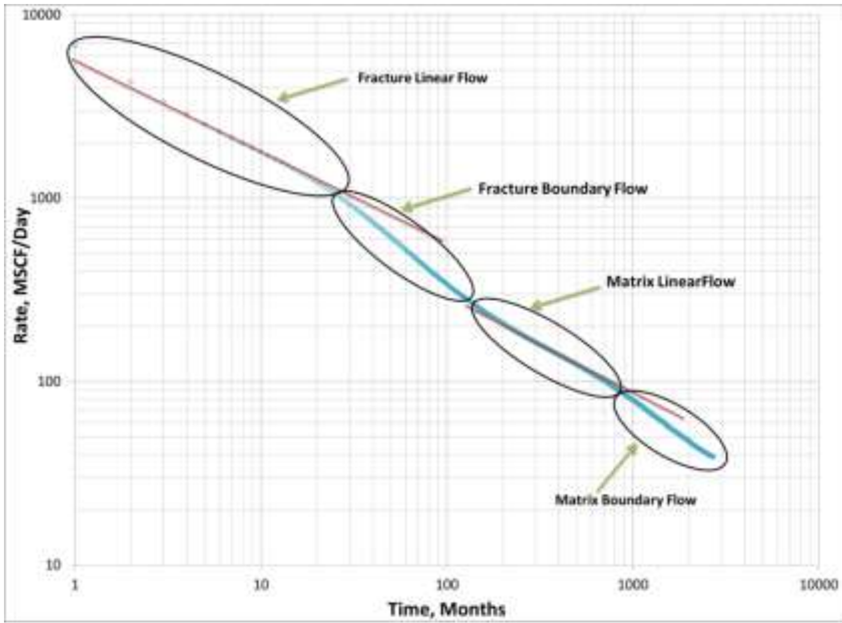

Figure 1-Flow regimes in a typical multi staged fractured horizontal well

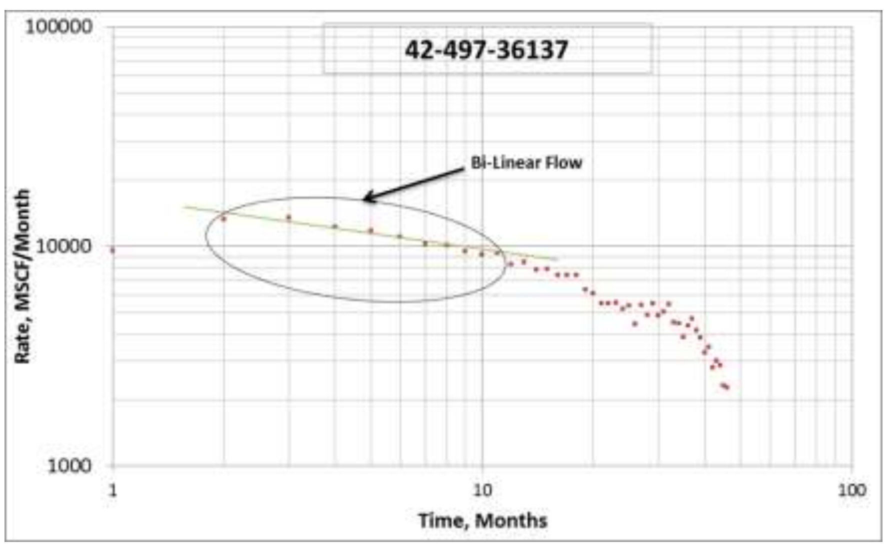

Figure 2- Bi-Linear flow observed in Wise county well # 42-497-36137

i) Fracture Linear Flow: A transient flow regime that occurs when the fracture boundaries have not yet been observed. The time that this regime lasts is dependent on the fracture spacing and the SRV permeability. In most shale wells this flow regime dominates the known life of the well. A negative half slope on a log-log plot of rate vs. time can be used to detect this linear flow.

ii) Fracture Boundary Flow: This flow regime occurs when fracture interference occurs. The time at which this regime occurs is dependent on the SRV permeability and fracture spacing. Many of the present horizontal shale wells have not yet observed this regime but some of the newer wells with huge fracture treatments have been observing this regime early. Fracture boundary flow can be observed on a log-log plot by deviation from a -1/2 slope line on a log-log plot of rate vs. time.

iii) Matrix Linear Flow: When production from the matrix, beyond the SRV, starts to dominate the production a linear type flow will be observed. This regime is most likely will not be observed in the economic life of the well. Similar to fracture linear flow, this regime can be observed using a negative half slope line on a log-log plot of rate vs. time.

iv) Matrix Boundary Flow: Once the outer matrix transient has reached the drainage boundaries of the well, a deviation from the negative half slope, corresponding to matrix linear flow, will be observed. This deviation is equivalent to matrix boundary flow. Comparable to matrix linear flow, this flow regime will most likely not be observed in the economic life of the well.

2.3 Overview of empirical models

As mentioned above empirical modeling is a widely used procedure to match and forecast production data. Analytical models were looked into but due to scarcity of formation and well data they were not studied in detail. The aim of this thesis is to compare empirical models and perform an uncertainty analysis on various shale and tight gas plays.

2.3.1 Arps decline curves

Starting with the traditional Arps decline curves, which were developed by J.J Arps empirically on some 149 oil fields production data using a constant loss ratio method(Arps 1945; Fetkovich et al. 1996). (Fetkovich et al. 1996) provides a clear understanding on the use of different decline model parameters for various types of formations and operating conditions.

The Arps Exponential Model is given by the following equation

$q = q_i \, e^{-Dit}$ ……………………………………………………………..1

The Arps Hyperbolic Model is given by the following equation

$q = q_i(1 + \mathrm{D}_i t)^{-1/b}$ ……………………………………………………………. 2

Where

q_i = Initial rate

b = Hyperbolic exponent

D_i = Initial decline rate.

With an increase in drilling in unconventional reservoirs, especially shale gas reservoirs, Arps' theoretical upper limit of a b factor of 1 has consistently been violated. "Empirical review of actual production data demonstrates a wide range of observed b-factors, often from 0.8 to 1.5 over the years of production" (Strickland et al. 2011).The micro/nano Darcys permeabilities observed in shale and tight sand reservoirs causes the b factor to be higher than 1 due to extended periods of bi-linear and linear flow regimes. Therefore fitting the entire historical data including the transient phases will yield abnormally high forecasts eventually leading to overestimating of reserves due to usage of high b factors (b>1). Care has to be taken to understand and classify the flow regimes of hydraulically fractured low permeability reservoirs before matching the complete historical data.

It has been rigorously demonstrated that the bi-linear and linear flow regimes correspond to b factors of 4 and 2 respectively (Kupchenko et al. 2008; Maley 1985; Spivey et al. 2001). For the boundary dominate flow regime in conventional reservoirs, (Fetkovich et al. 1996)has shown that the b factor lies somewhere between 0 and 1 depending on the fluid and characteristics of the formation.

2.3.2 Minimum decline model

The minimum decline model is a modification of the Arps decline model. In this method the data is modeled and forecasted using the hyperbolic Arps equation up to a certain predetermined decline rate, after which the decline shifts to an Arps exponential decline model. If the minimum decline model is used after the predetermined rate is reached the forecast declines at a constant decline rate. According to Lee and Sidle, 2010 the minimum decline model produces forecasts that appear to be reasonable but there is no physical basis for it.

The decline rate at any time can be calculated using the following equation:

$$D = -\frac{\frac{\Delta q}{q}}{\Delta t} \quad \ldots\ldots 3$$

If the terminal decline rate is D_{term} then the time at which the decline changes from hyperbolic to exponential is given by equation 4.

$$t = \frac{\left(\frac{D_i}{D_{term}} - 1\right)}{bD_i} \quad \ldots\ldots 4$$

Once the rate at which the decline changes from hyperbolic to exponential is obtained, the time obtained in equation 4 and D_{term} is plugged into the exponential model in equation 2. This exponential decline is then held until end of economic life of the well. If a minimum decline model is used then at a certain predetermined rate the decline rate remains constant at the specified rate. In this work, I will compare the minimum decline technique, which is also the most widely used technique in the industry, to other newer techniques. For the minimum decline model, a minimum decline rate of 5% is used.

2.3.3 Stretched exponential production model (SEPD)

The SEPD is a production decline model based on the function in **Eq.5**, developed by Valko and Lee. The rate equation, as a function of time, of the SEPD as proposed by Valko and Lee, 2010 is

$$q = q_0 \exp\left(-\frac{t}{\tau}\right)^n \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \ldots\ldots 5$$

Where

τ = Characteristic time constant

n = Exponent parameter

q_o = Initial production rate

The parameters τ and n are shape and scale factors while qo determines the point of start of the curve. The two advantages this model has over the Arps declines method is that the EUR is bounded and it is designed for transient flow, unlike the Arps model, which is intended to be used for BDF (Valko and Lee 2010).In previous studies this decline method has been tested on grouped data sets and has proved to work well for historical data in the range of 36 months.

2.3.4 Duong forecasting method (Duong, 2010)

The Duong method is a new forecasting technique based on long-term linear flow. This method proposed by Duong (2010) consists of two equations to calculate parameters a, m and q_1. Equation 6 is used to calculate the parameters a and m using regression analysis.

$$\frac{q}{G_p} = at^{-m} \quad \ldots\ldots 6$$

As observed in **Figure 3** a straight line drawn through the data provides us with a slope and intercept that correspond to the parameters a and m. The values of a and m were obtained as 0.731 & 1.067 respectively.

Once a and m are determined, q_1 is determined by plotting the flow rate versus t (a,m) thru Equation 7 and 8 and using regression analysis, the plot in **Figure 4** is a straight line through the data where the slope provides us with q1 and the intercept with q_∞.

$$q = q_1 t\,(a, m) + q_\infty \quad \ldots\ldots 7$$

Where

$$t(a,m) = t^{-m} e^{\frac{a}{1-m}\left(t^{1-m}-1\right)} \quad \ldots\ldots 8$$

Figure 5 shows a semi log plot of the production decline forecast using the a, m and q_1 parameters for the well 42-121-32269 in Denton county, Barnett shale.

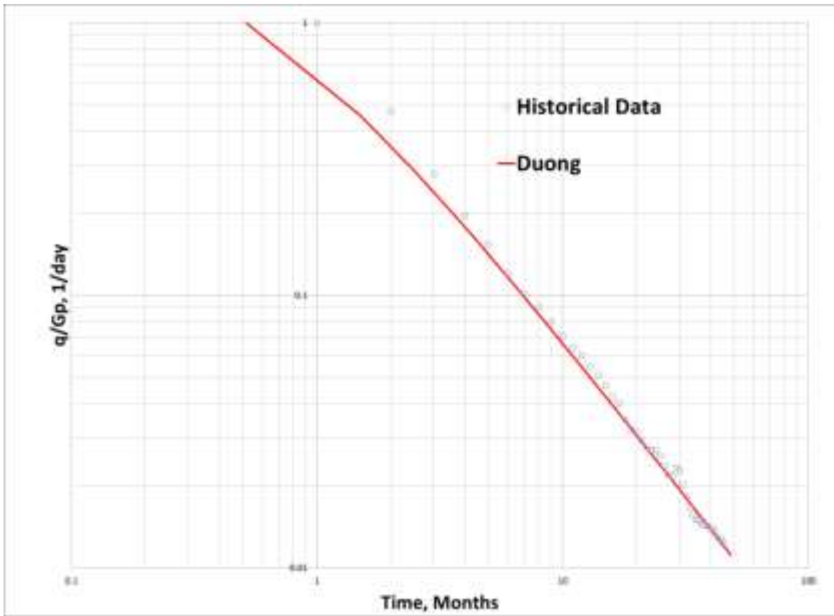

Figure 3 -a and m determination for a Denton county, Barnett shale well

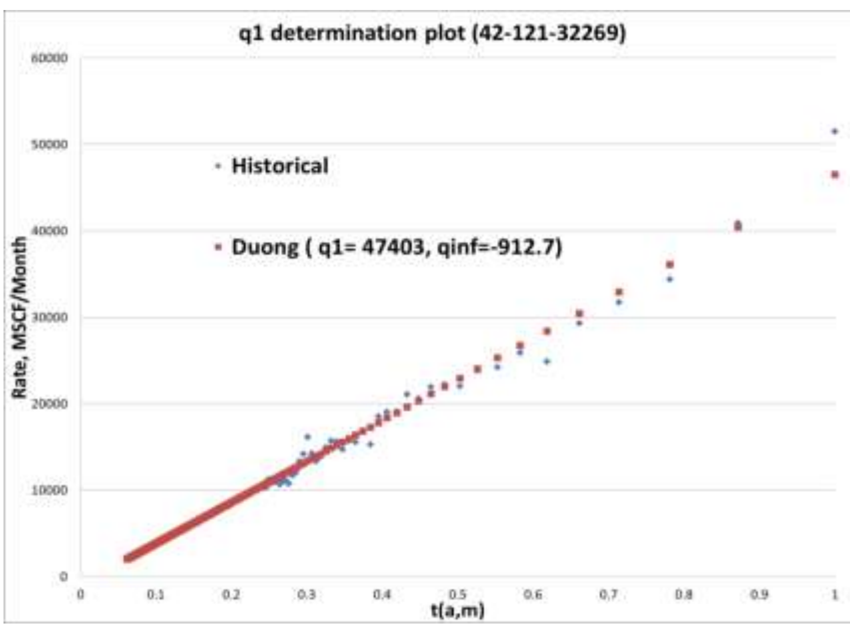

Figure 4- q1 determination of a Denton county, Barnett shale well

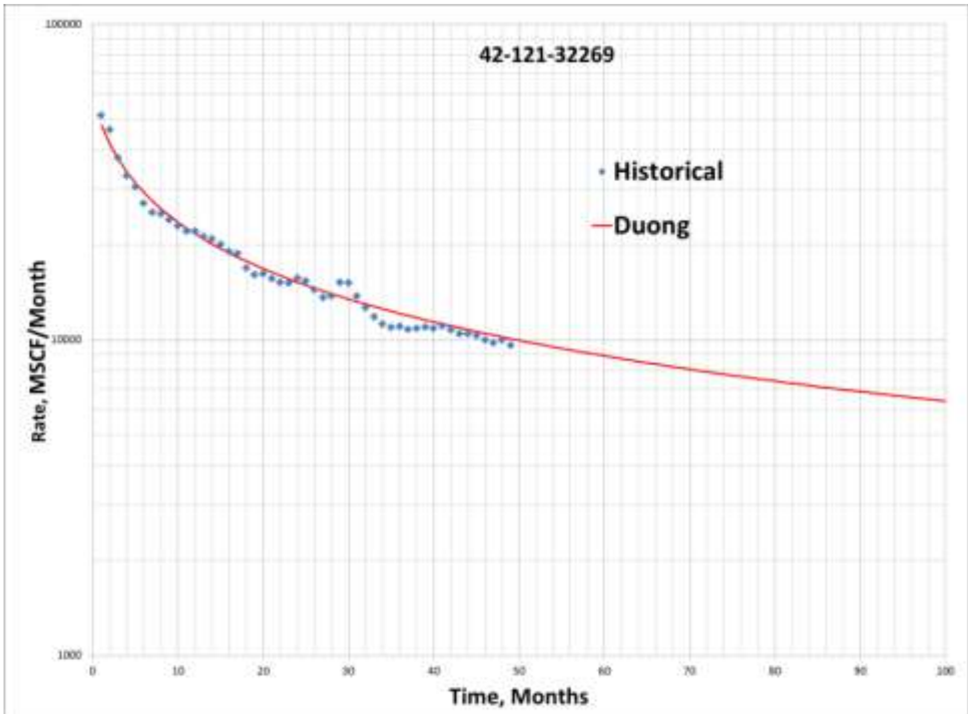

Figure 5- Duong production forecast for 42-121-32269

A more in depth study on the Duong method is performed in succeeding chapters.

CHAPTER III

IN- DEPTH ANALYSIS OF THE DUONG FORECASTING METHOD

3.1 Modifications to the Duong model

In the previous chapter a brief discussion was presented on how Duong suggested calculating the parameters a, m, q_1 and q_∞. It has been observed in this research that using q_∞ is incorrect for some field cases and all simulated cases.

According to the Duong, 2010 the q vs. t (a, m) plot should give a regressed straight line through the origin but due to current operating conditions that may not be the case. This statement is true to some degree I have statistically shown that a well with 6 to 18 months of data forcing the regressed line, on the q vs. t (a, m) plot, through the origin (q_∞=0) gives the smallest error in remaining reserves. **Table.1** shows a comparison of the error % in remaining reserves between the line forced through the origin and the line using q_∞ for different amounts of matched months. In the **Table.1** the values highlighted in yellow are statistically more accurate. But for wells that show bi-linear flow it has been observed in **Table.2** that using a value for $q\infty$ works much better. In the field data set used for this study only 6% of the wells were found to indicate a substantial period (>3months) of bi-linear flow.

Table 1- Short term forecast comparisons for discrepancy (% error) in remaining reserves

		6_Duong_qinf	6_Duong_qinf=0	12_Duong_qinf	12_Duong_qinf=0
All Wells	Mean	9.94	-17.58	8.70	-9.08
	Std.Dev	51.29	32.65	22.34	18.27
	% Wells <15 % error	22.80	42.40	46.80	64.80

Table 2- Short term data forecast discrepancy (% error) comparisons in remaining reserves for bi-linear flow wells

	Error in remaining reserves	12_Duong_qinf	12_Duong_qinf=0	18_Duong_qinf	18_Duong_qinf=0
Only	Mean	-0.29	-14.49	-5.32	-15.27
Bi-linear wells	Std.Dev	13.84	11.69	10.89	8.91

Another feature of the Duong forecast for limited data is the magnitude of q_∞. In many cases q_∞ has a major impact on the predicted rate for 6 to 12 months of matched data. If q_∞ is largely negative (-ve) it can produce a forecast like the one seen in **Fig. 6**. A –ve qinf implies the x-intercept in the plot shown in **Fig.4** is –ve.

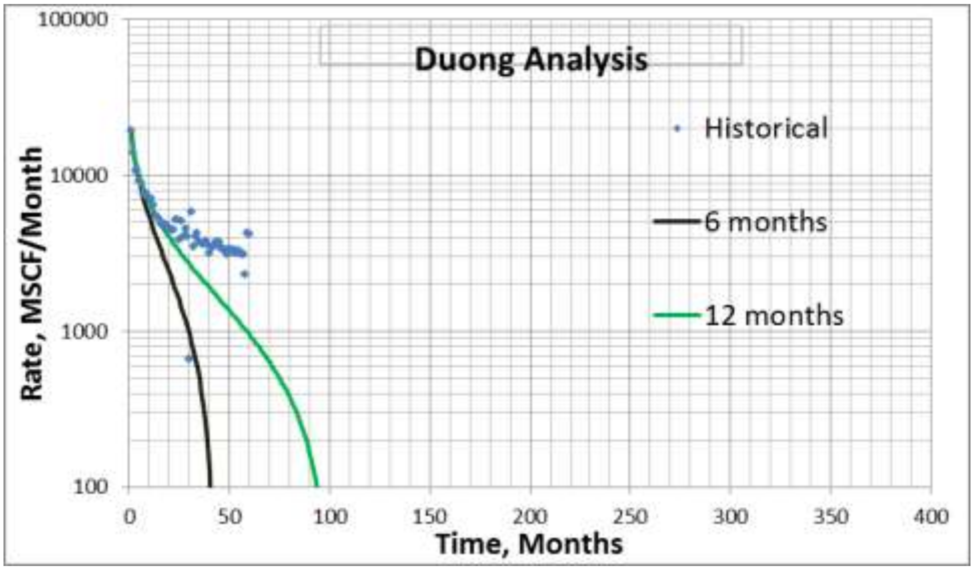

Figure 6- Duong forecasts having a large –ve q∞. (API: 42-497-35836)

The well in **Fig.6** has a q_{∞} of -2524 MSCF/Month for 12 months and -3964 MSCF/Month for 6 months of matched data. In this case the large –ve q_{∞} was leading the forecast to negative production rates; therefore the forecast was bounded to a production rate of zero. This is evident in **Figure 7** where the cumulative forecasts flatten out after a certain month. The q vs. t (a, m) plot, corresponding to **Fig.6,** is shown in **Figure 8**.

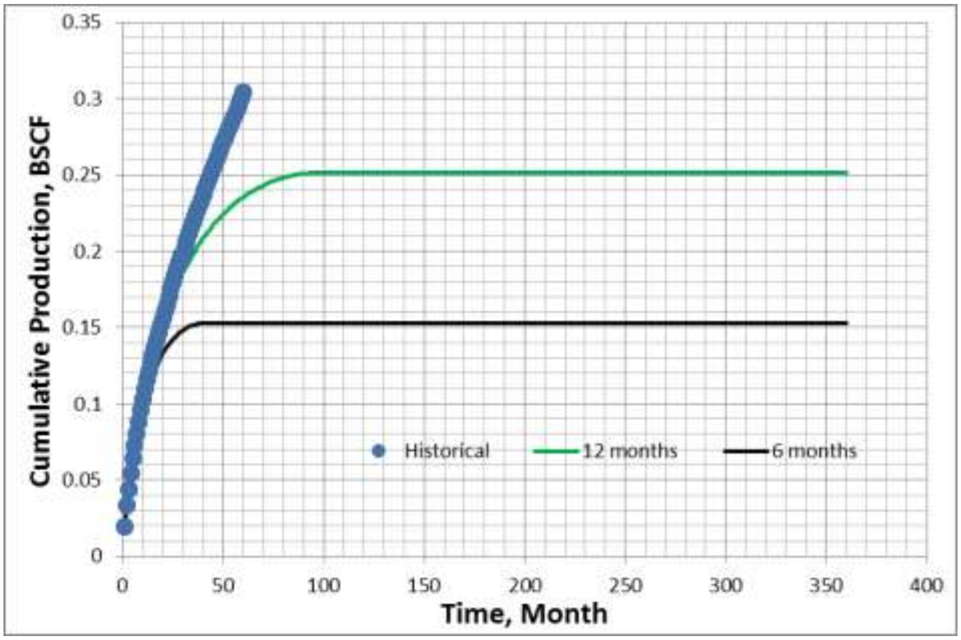

Figure 7- Cumulative production of Duong forecasts (API: 42-497-35836)

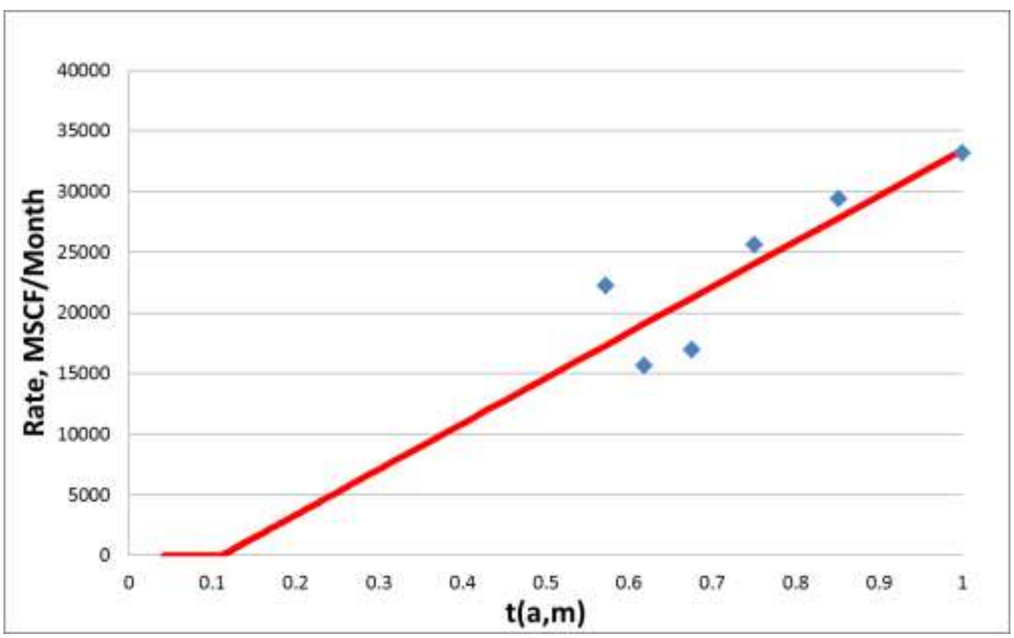

Figure 8- q∞ determination plot for 6 months data (API: 42-497-35836)

To avoid this abnormality caused by irregular q_∞ values, if q_∞ is forced through the origin the forecast turns out to be more accurate. In **Fig. 9** q_∞ is forced through the origin, for the same well in **Fig.6,** thereby providing a more realistic and precise forecast. The cumulative forecast in **Fig. 10** too endorses the forcing of $q\infty$ through the origin. The corresponding q vs. t (a, m) plot for the forecasts in **Fig.9** and **Fig.10** is shown in **Fig. 11**. This does not mean that the Duong forecast, with forcing q_∞ to be zero, is perfectly accurate for limited data. It still has a forecasting discrepancy associated with it as indicated in **Table 1** but on average forcing $q\infty$ to be equal to zero works better in comparison to q_∞ not equal to zero for limited data.

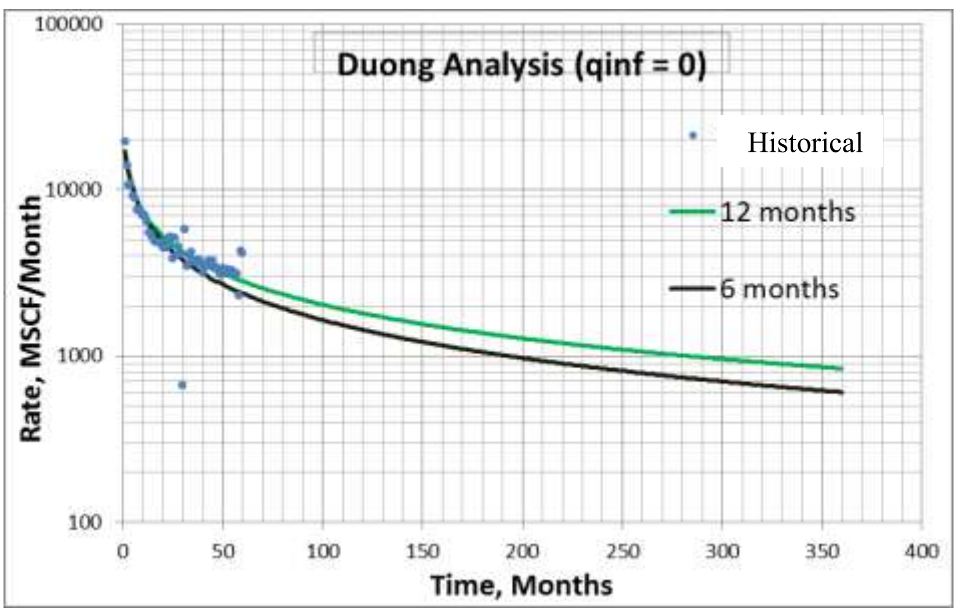

Figure 9- Duong forecasts by forcing $q\infty$ to 0. (API: 42-497-35836)

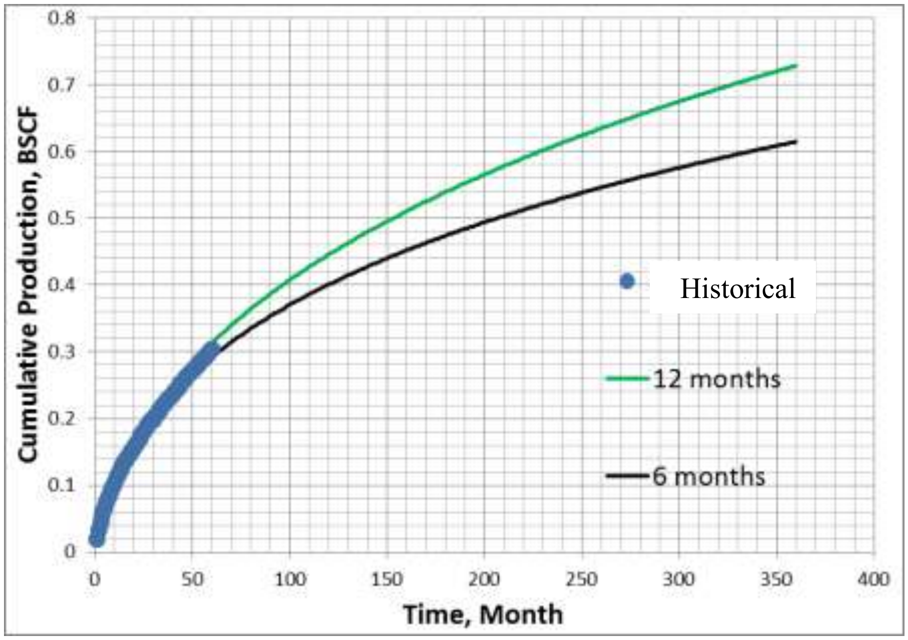

Figure 10- Cumulative production of Duong forecasts if q∞=0 (API: 42-497-35836)

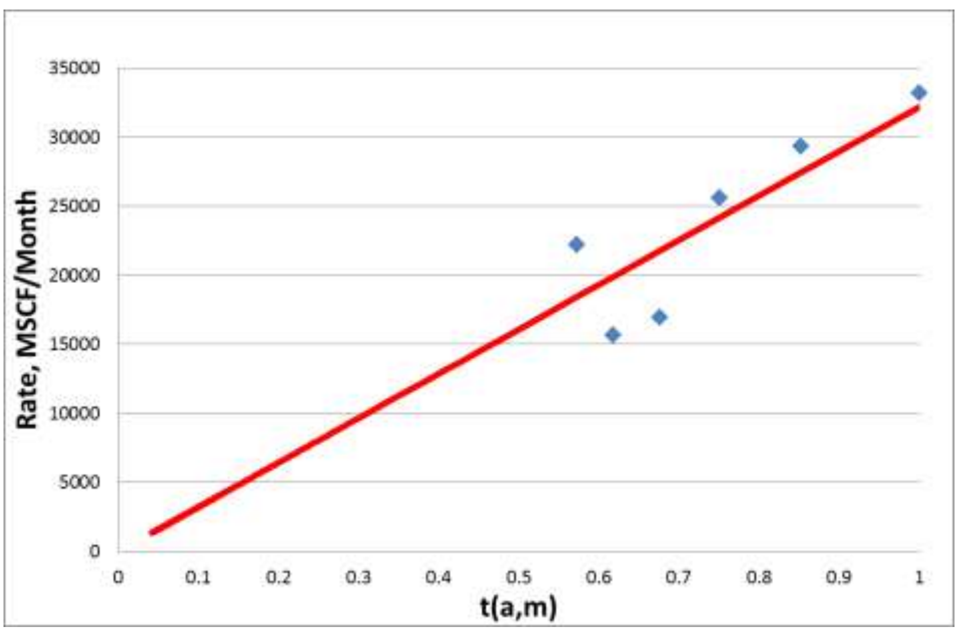

Figure 11- – q∞ determination plot for 6 months data. Forcing q∞=0 (API: 42-497-35836)

For wells with greater than 24 months of data using a q_∞ is marginally better than using a q_∞ of zero. For a group of 228 randomly selected wells, **Table 3** shows that using $q\infty$ is slightly better that forcing $q\infty$ through the origin.

Based on **available field data** the optimal way to forecast production data using the Duong method, in regard to q_∞, would be to force q_∞ through zero for limited data (6-18 months) and use a q_∞ value for data more than 24 months. An example of this combination is displayed in **Fig. 12** and **Fig. 13**.

Table 3- Discrepancy (% error) in remaining reserves comparisons for wells with 36months of history matched data

		36_Duong_qinf=0	36_Duong_qinf
All Wells	Mean	-4.48	1.18
228	Std.Dev	18.53	16.45
	% Wells <15 % error	68.42	71.05
Excluding BDF	Mean	-3.62	3.05
187	Std.Dev	18.72	16.27
Only BDF	Mean	-8.36	-7.39
41	Std.Dev	17.33	14.59

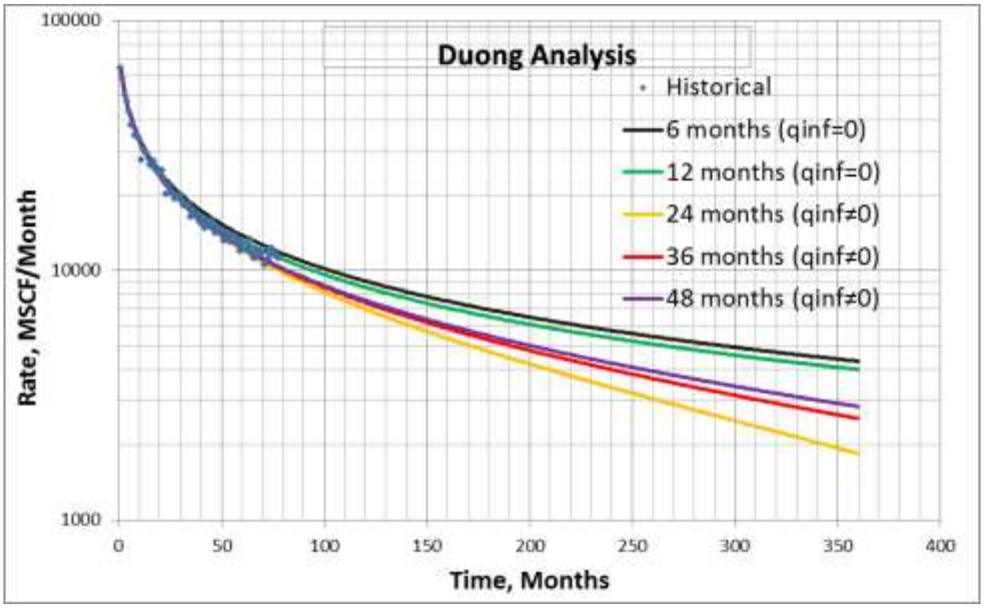

Figure 12- Optimum combination of q∞ for varying amounts of data

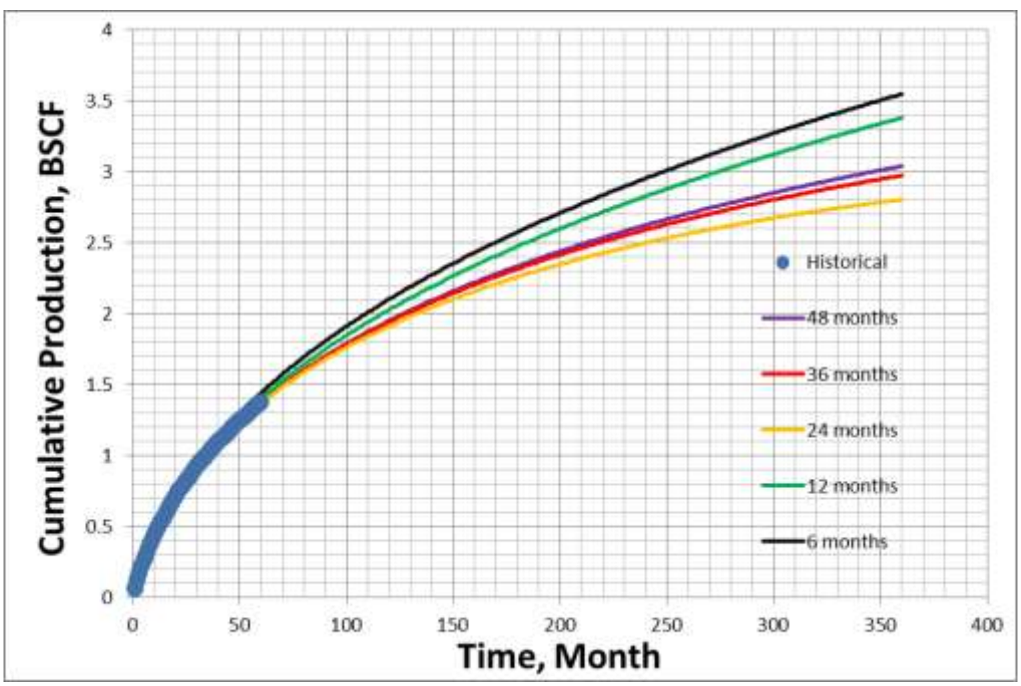

Figure 13- Cumulative production plot of the optimum combination of q∞ for varying amounts of data

Since the longest month in the field data set is 88 months it would be naïve to propose that using q_∞ for 24 months or more matched production data will provide acceptable forecasts for 30 years. Therefore it was imperative to compare our forecasts with simulated data lasting for longer periods of time. If the forecasts were compared to simulations lasting for 30 years, forcing q_∞ thru 0 provides a better fit than solving for q_∞ as laid out by Duong in SPE137748. The evidence of this claim is provided in the cumulative forecasts of a Barnett shale simulation in **Figure14** and **Figure 15**. Therefore all future Duong forecasts, unless specified will assume a $q\infty$ through the origin on the q vs. t (a, m) plot. The further use of q_∞ will be reexamined in following chapters where the accuracy of the Duong model is examined.

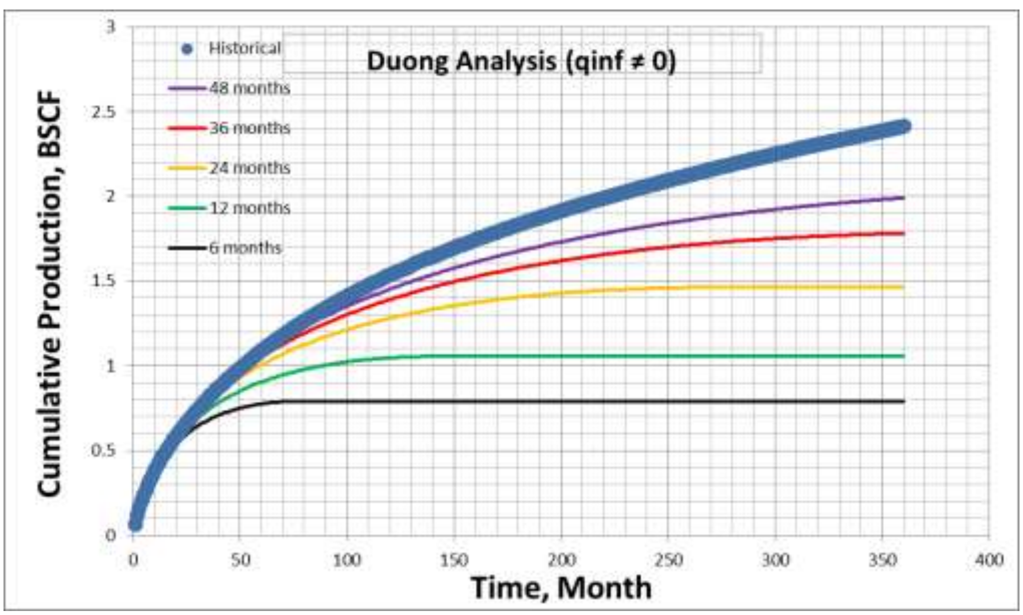

Figure 14- Cumulative forecasts using $q\infty \neq 0$ for a Barnett shale simulation

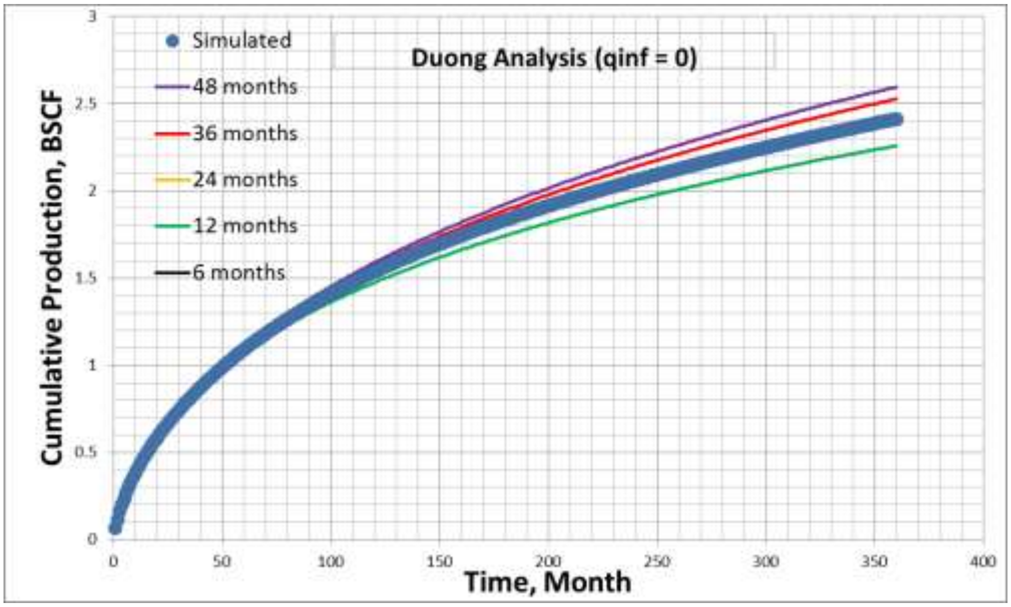

Figure 15- Cumulative forecasts using q∞ =0 for a Barnett shale simulation

Earlier it was mentioned that in shale gas reservoirs fracture linear flow is followed by fracture BDF. According to Duong, his method is based on long term linear flow therefore using the Duong model as it is may or may not work for wells that exhibit BDF. Since we are in the early life of many shale gas wells, BDF is not observed but there have some instances where BDF is observed. It is observed in **Table 3** the Duong model does an ordinary job in modeling BDF for 41 wells. But again the error in remaining reserves was calculated for only 60-80 months of production data. Therefore it was necessary to use simulations to verify the application of the Duong model for longer histories.

It is a well-known fact that Arps developed his hyperbolic equation for BDF conditions. As mentioned above, (Fetkovich et al. 1996) had provided a tabulation of b values and its use for various drive mechanisms. In this study it is proposed that the Duong method be coupled with the Arps hyperbolic decline curve for gas wells. This union of the Duong followed by an Arps curve at a predetermined decline rate is appropriate since it is theoretically correct as it models the various flow regimes in the reservoir. Fetkovich et.al, (1996) mentions the use of b =0.4 to 0.5 for gas wells where b=0.5 for $p_{wf}\approx 0$ and b=0.4 for $p_{wf}=0.1*p_{Ri.}$ It has been observed in the field that pwf is never taken down to 0 and in a lot of the field cases $p_{wf}\approx 0.1*p_{Ri.}$ Therefore in this study a Modified Duong is proposed for shale gas reservoirs. The Modified Duong method deviates from the original equation switching to an Arps decline curve with b=0.4 at a decline rate of 5%. The modified Duong method is compared to the original Duong method for 50 shale simulations, with total production lasting 30 years, in **Table 4.** For early months the variation between the original Duong and Modified Duong method is not large but for longer history matched periods the modified Duong method works better with a smaller discrepancy in remaining reserves. A graphical example of the variation is displayed, for a Barnett shale simulation, in **Fig. 16** where fracture boundary flow (BDF) commences at 85 months**.**

Table 4- Discrepancy (% error) in remaining reserves for 25 Barnett and 25 Marcellus shale simulations

	Error % in remaining reserves			
History Matched		**Duong _qinf=0**	**Duong_qinf≠0**	**Modified Duong (Dswitch @5%)**
12	Mean	4.44	86.94	5.55
	Std.Dev	17.71	6.51	17.43
18	Mean	-6.08	69.42	-4.33
	Std.Dev	16.24	11.71	16.09
24	Mean	-0.74	36.20	1.00
	Std.Dev	13.12	15.26	13.10
36	Mean	-17.05	45.97	-13.97
	Std.Dev	9.54	13.26	9.84
48	Mean	-17.39	33.09	-13.88
	Std.Dev	8.01	10.84	7.99

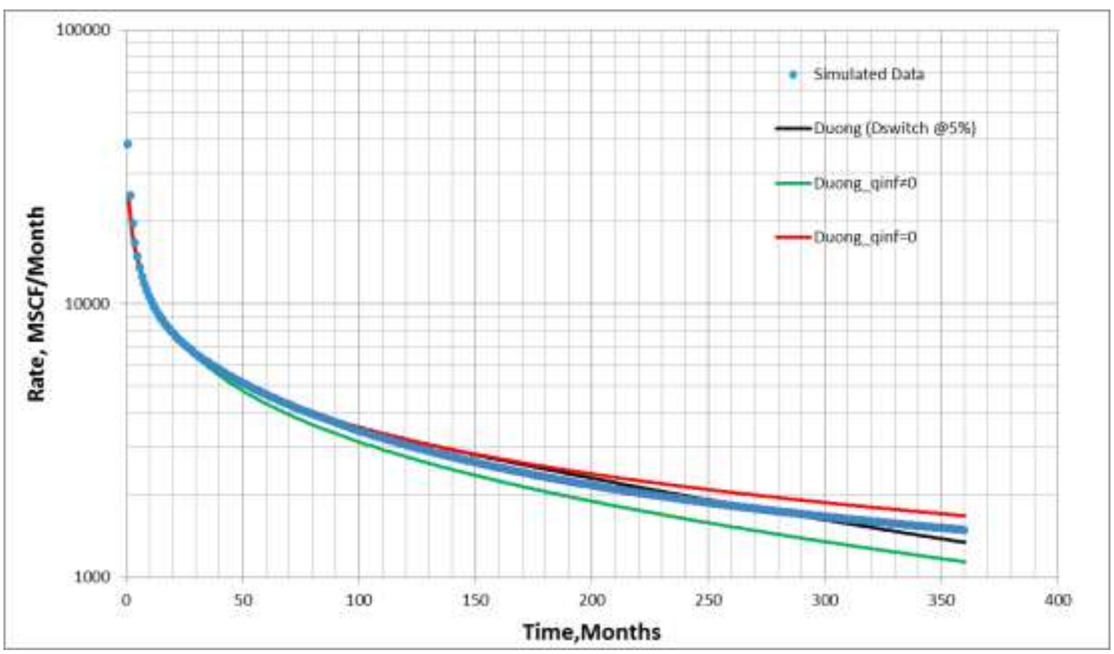

Figure 16- Comparison of the Duong and Modified Duong (Dswitch @5%) for a Barnett shale simulation. (48 months history matched)

It was also suggested to switch from Duong to Arps at 5 years instead of a specific decline rate of 5%, but as evident in Table 5 and Table 6, switching to Arps (b=0.4) at 5% works better.

Table 5- Discrepancy (% error) in remaining reserves comparisons for 12 months of history matched data

		12_Duong_No Dmin	12_Duong_Dwitch@5%	12_Duong_Dswitch @5years
All Wells	Mean	-9.08	-7.77	-9.54
	Std.Dev	18.27	17.48	19.19
	% Wells <15 % error	64.80	66.70	62.80

Table 6- Discrepancy (% error) in remaining reserves comparisons for 24 months of history matched data

		24_Duong_No Dmin	24_Duong_Dwitch@5%	24_Duong_Dswitch @5years
All Wells	Mean	-6.25	-2.49	-6.61
	Std.Dev	15.99	16.13	16.53
	% Wells <15 % error	72.80	72.80	72.80

Therefore amongst the above variations of the Duong model which includes the Original Duong, Duong ($q\infty$=0), Modified Duong (Dswitch @5%) & Modified Duong (Dswitch @5 years), the Modified Duong (Dswitch @5%) works the best for the fields looked at in this thesis. There is a possibility that a different Dswitch could be optimum but is evident that even using 5% as a Dswitch works better than the original Duong method.

3.2 Accuracy of the Duong model for field data

There is huge demand in the industry to accurately forecast gas production using limited data due to limited durations of production histories of shale wells. The Duong method does a reasonable job in forecasting short term production data. Various numbers of months were history matched and the distribution of the error/discrepancy in remaining reserves is tabulated in **Table 7a**. The question then arises what constitutes an acceptable match? In this study an assumption has been made that if the absolute error is less than 15%, the hindcast is acceptable. Also the standard deviation along with the mean, in the table, exhibits the range and magnitude of the error. As mentioned above the 250 well data consists of post 2004 drilled hydraulically fractured horizontal wells in the Barnett and Fayetteville shale. 50 wells each from the Denton, Johnson, Tarrant and Wise counties were selected from the Barnett shale while 50 wells were randomly selected from the Van Buren county in the Fayetteville shale. The variation of Duong that I used for all forecasts in this chapter, unless specified, is the Modified Duong (Dswitch @5%) with q_{∞}=0. The words Modified Duong and Duong_Dswitch @5% are used interchangeably. In **Table 7b** the statistics have been re-calculated using absolute values of the errors of the individual wells. But using absolute error & errors with algebraic signs leads to the same conclusion. Using algebraic signs, when calculating the statistics, helps to identify whether a particular method, "on average", overestimates or underestimates true production data. A negative mean values means the forecasting technique overestimates the data while a positive value indicates underestimation. But whether absolute or a real value is used the method that minimizes the mean & standard deviation is the best method.

Table 7a-Discrepancy (% error) in remaining reserves comparisons for varying months of history matched data

Discrepancy (error %) in remaining reserves for a field dataset		
History Matched		**Duong_Dswitch@5%**
6	Mean	-15.98
	Std.Dev	29.24
	% Wells <15 % error	45.60
12	Mean	-7.77
	Std.Dev	17.48
	% Wells <15% error	66.80
18	Mean	-6.90
	Std.Dev	14.41
	% Wells <15 % error	71.60
24	Mean	-2.49
	Std.Dev	16.13
	% Wells <15 % error	72.80
36	Mean	-5.04
	Std.Dev	17.88
	% Wells <15 % error	71.93
48	Mean	-5.45
	Std.Dev	18.08
	% Wells <15 % error	77.16

Table.7b- Discrepancy (% error) in remaining reserves comparisons for varying months of history matched data using absolute error values used to calculate statistics

History Matched ------->	6	12	18	24	36	48
Mean	23.51	14.00	12.01	12.62	12.71	12.28
Std.Dev	25.90	13.02	10.51	12.40	13.76	14.32

It is evident in **Table 7a** that for 6 months of production data the Duong model does not work that well as we would desire. Even though the forecasts get more accurate as more production data is acquired the Duong forecasts are acceptable with 12 months of history matched data compared to 36 months. An example of a Duong forecast with various months of history matched is shown in **Fig. 17 and Fig. 18.** Similar to the results in **Table 7a** the well in **Fig.17 and Fig.18** provides better forecasts as more data is matched. I have been observed that the forecasts generally get increasingly better as more data is matched up to 18 months but only incrementally better if 18-48 months are matched. Therefore on average it can be said that 18-24 months of available data would provide similar forecasts to 24-48 months of data.

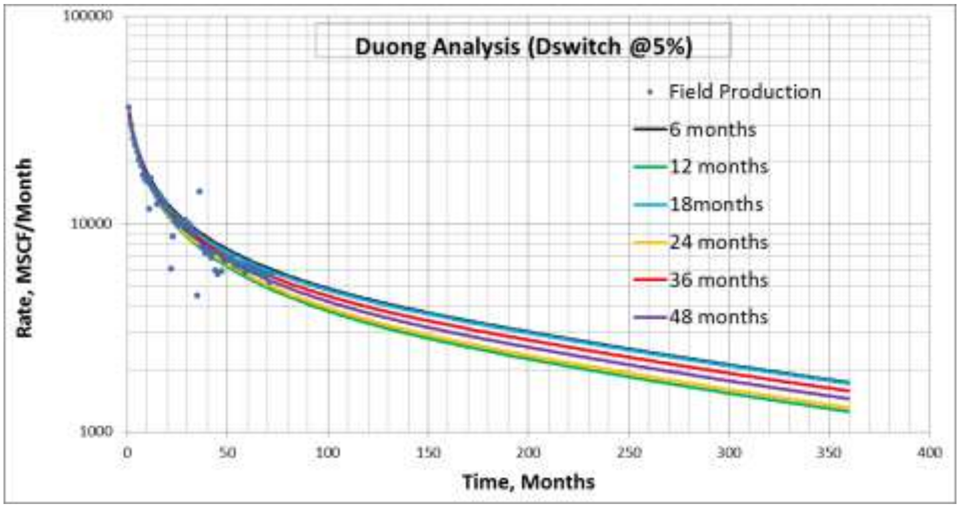

Figure 17- Production forecast comparisons for various history matched months for Well API# 42-497-35737

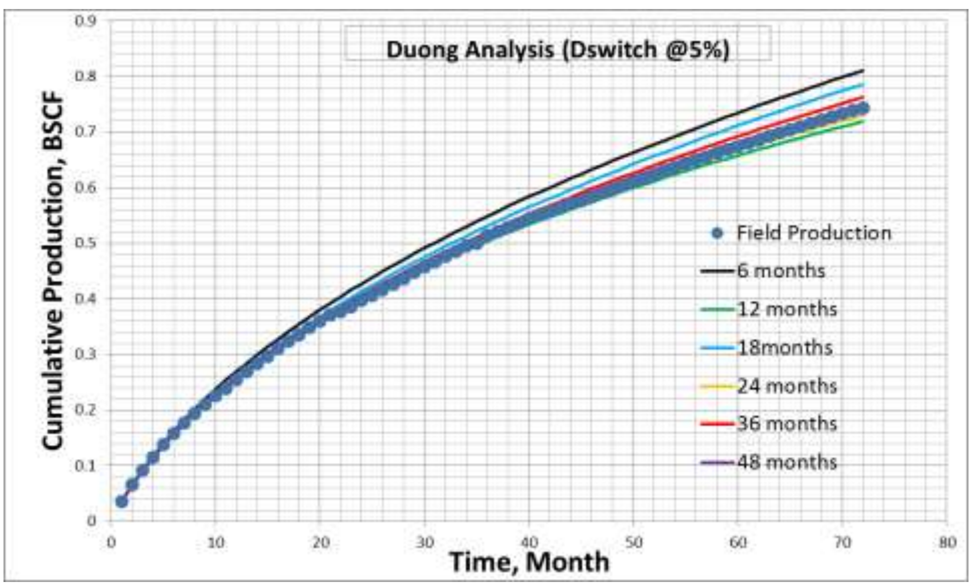

Figure 18- Cumulative forecast comparisons for various history matched months for Well API# 42-497-35737

It is also interesting to see the distribution of forecast discrepancies for wells from each county in the data set. **Table 8** shows the distribution of the error in remaining reserves for each county.

Table 8- County wise discrepancy (% error) in remaining reserves comparisons for varying months of history matched data

History Matched	Statistics	Wise	Tarrant	Johnson	Denton	VanBuren
6	Mean	-14.00	-15.28	-17.06	-5.04	-30.39
	Std.Dev	48.08	30.78	28.02	15.12	17.33
	% Wells <15 % error	52	34	50	72	18
12	Mean	-4.07	-9.09	-7.52	-3.41	-15.06
	Std.Dev	16.50	23.98	18.48	12.86	10.86
	% Wells <15 % error	78	48	62	86	60
18	Mean	-3.91	-8.74	-8.27	-4.92	-9.35
	Std.Dev	14.35	20.12	15.79	10.11	8.67
	% Wells <15 % error	74	52	68	90	76
24	Mean	-4.62	-9.56	-7.18	-5.98	-8.60
	Std.Dev	19.56	18.47	19.68	9.33	10.83
	% Wells <15 % error	76	52	70	86	80
36	Mean	-7.09	-4.97	-2.81	-3.10	-4.72
	Std.Dev	12.16	17.64	24.38	7.96	16.81
	% Wells <15 % error	76	65	42	96	76
48	Mean	-7.85	-5.89	-5.13	-3.17	-1.24
	Std.Dev	8.56	21.87	28.27	7.26	6.28
	% Wells <15 % error	80	56	62	94	100

In the above table it is evident that for 6 months of data the Duong method does not forecast accurately. But for 12 months or more of history matched data the Duong method provides acceptable forecasts for all counties except the Tarrant county. Actually when the Duong method when applied for wells in the Tarrant county the discrepancy in remaining reserves is high. But with further investigation it was discovered that around 2007-2008 a change in pipeline pressure caused a major change in production for the wells in the Tarrant county. This change in production is evident in **Fig. 19,** which displays the production trend of an aggregation of 205 wells in the Tarrant county. In the below figure it is apparent that there has been have major operational changes at around 40 months which corresponds to the year 2007-2008. Since Tarrant county is a core area of the Barnett shale and combined with the shale gas boom it is speculated that around the year 2007-2008 a dramatic change in gathering line pressure changes took place which led to a sudden increase in the production trend. This has been confirmed by an engineer at EnCana Energy. Such a jump in production cannot be predicted by any decline curve technique unless pressure is incorporated in the analysis.

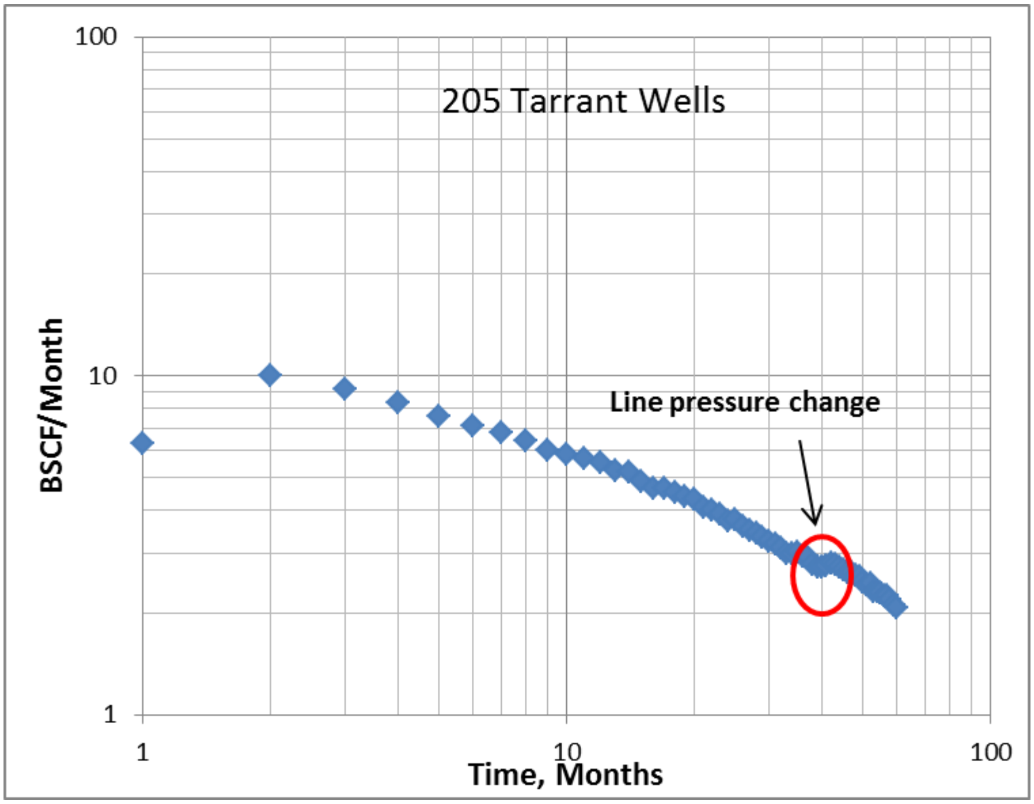

Figure 19- Production decline trend for a group of 205 wells from the Tarrant county

3.3 Accuracy of the Duong model for field BDF wells

In the dataset that was looked at above, only 18% of the wells displayed BDF in the available production history of the well. With newer completion techniques, increased number of fracture stages and decreased fracture spacing it is highly possible that boundary flow may be observed earlier and more often than in the Barnett shale wells. In this study an analysis is performed on field data to ascertain the efficacy of various decline models on forecasting boundary flow. Two types of analysis are performed to match boundary flow. The first is to history match assuming boundary flow will occur in the future life of the well and the second is to history match data where boundary flow is present in the history match.

For the field data used in this study boundary flow typically begins after 50 months. Since the average life of the well in this study is around 60-70 months for the Barnett shale, there is not enough data to incorporate BDF in the history match and perform a satisfactory hindcast For the Fayetteville shale wells BDF occurs earlier than the Barnett shale wells at around 30 months but the average available life of the Fayetteville shale is 40 months. This is proof of the statement made in the above paragraph that BDF tends to begin earlier for newer wells with more sophisticated fracturing technologies since the Fayetteville shale is newer than the Barnett. But since major drilling began in the Fayetteville shale in around 2007-2008, there is not enough data, similar to the Barnett shale, to incorporate BDF in the history match and perform a satisfactory hindcast. Therefore for field data, the only analysis performed is where BDF is predicted to occur after the history match is performed.

The Modified Duong method was tested on BDF wells in the Barnett and Fayetteville shale. The results of this analysis are shown in **Table 9** and as mentioned above BDF is not included in the history match due to unavailability of enough data after the history match to obtain an acceptable assessment of the hindcast.

Table 9- Discrepancy (% error) in remaining reserves for BDF wells

Error % in remaining reserves for BDF wells (BDF excluded in history match)				
History Matched	No.of Wells	Statistics	Duong_qinf≠0_Dswitch@5%	Duong_qinf=0_Dswitch@5%
6	47	Mean	-19.12	-38.96
		Std.Dev	60.25	45.40
12	47	Mean	-8.19	-19.90
		Std.Dev	24.56	19.40
18	47	Mean	-6.92	-14.11
		Std.Dev	17.94	16.62
24	47	Mean	-7.77	-13.25
		Std.Dev	15.91	20.99
36	41	Mean	-7.37	-8.50
		Std.Dev	14.56	15.35
48	33	Mean	-10.77	-10.52
		Std.Dev	16.03	14.94

In the above table it is evident that the Modified Duong with q_∞=0 performs poorly for short term data. But it is also observed that if q_∞ is not forced through the origin the forecasts are much better than forcing the Modified Duong through the origin. Therefore based on the above table it would be advisable to use Modified Duong (Dswitch @5%) but not forcing q_∞ through 0 for field BDF wells. It can also be ∞erred from the above table that as more data is acquired the forecast gets more accurate**.** **Figure 20** and **Figure 21** show the difference between q_∞ and forcing it through the origin for the modified Duong (Dswitch @5%). What is evident from these two plots is that the Modified Duong with a q_∞ performs better, than forcing q_∞ through the origin, for the known history of the well. But it also should be noted that using a q_∞ also leads to a huge difference in EUR between 6-12 and 24-48months months of matched data. As mentioned in the chapter 3.1, the effect of q_∞ it is clearly displayed in the Fayetteville well shown below. Like observed in the case below using a q_∞ may provide accurate forecasts for near term periods or in some cases for the life of the well but it can also lead to unrealistic forecasts especially for short term history matches. But in **Fig.21** it is observed using the Modified Duong method with $q_{\infty}=0$ may not always provide a right match for short term data but it will not blow up like seen in **Fig.20**. For greater than 18 months of matched data it is evident in **Fig.21** the Modified Duong method with $q_{\infty}=0$ works exceptionally well.

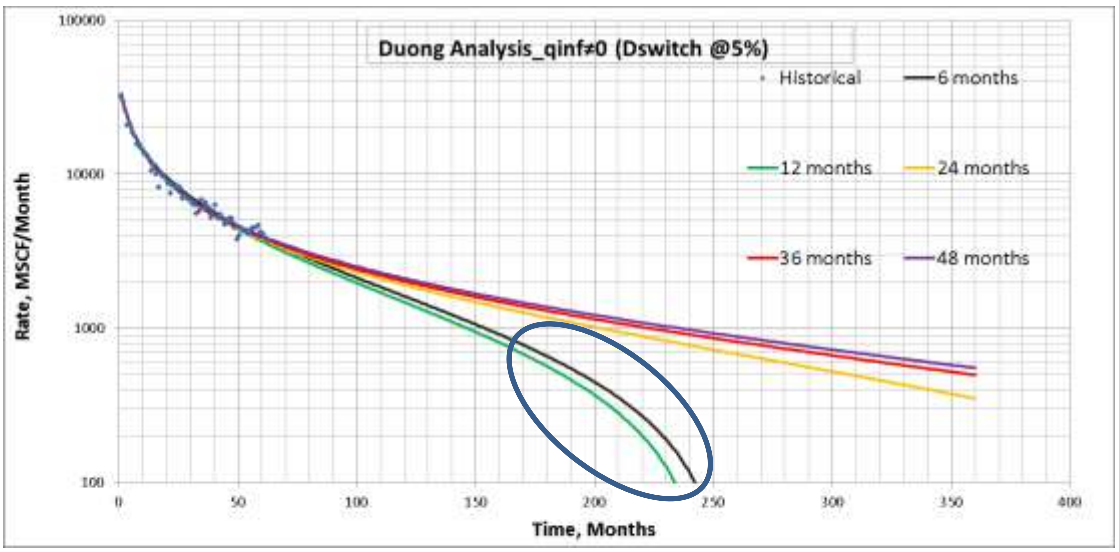

Figure 20- Production forecast comparisons, using a q_{∞}, for various history matched months for Well API# 383664348 (Fayetteville shale)

In another example, **Fig. 22** shows the extreme effect of using q_{∞} while **Fig. 23** shows a case when forcing q_{∞} to be 0 is better for a BDF well.

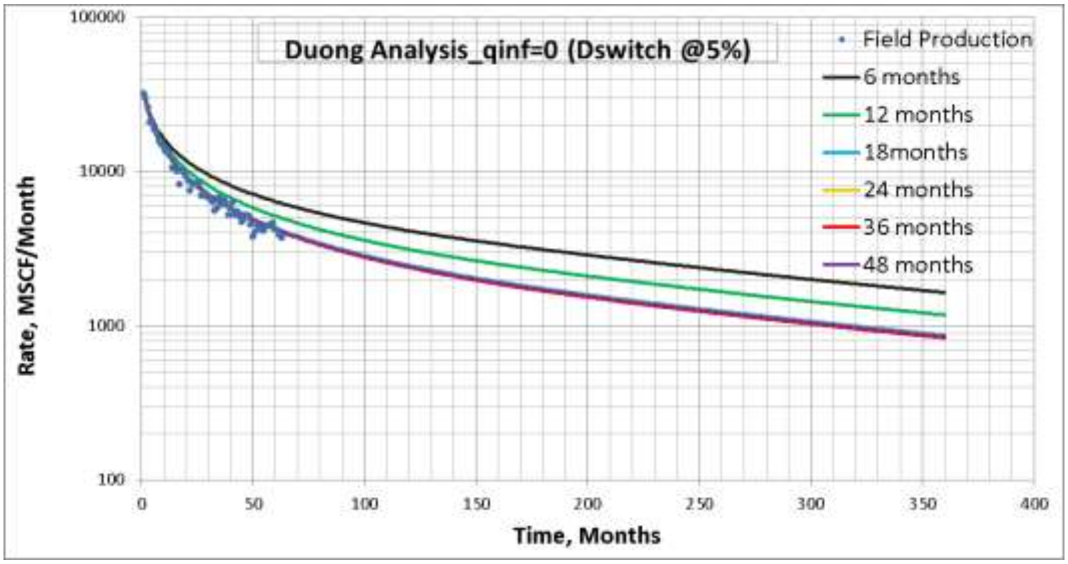

Figure 21- Production forecast comparisons, assuming q_{∞}=0 for various history matched months for Well API# 383664348 (Fayetteville shale)

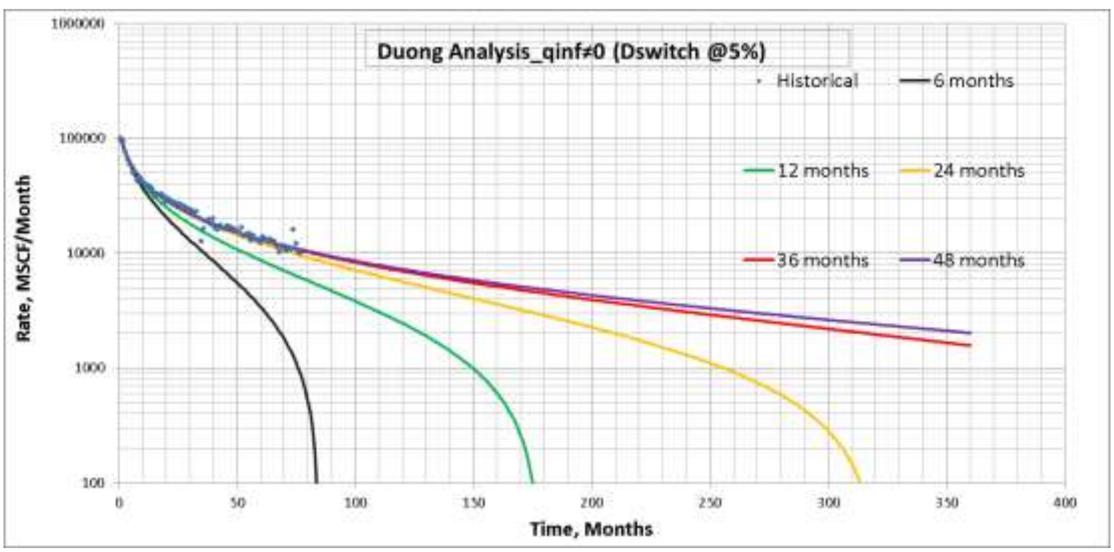

Figure 22- Production forecast comparisons, using a q_{∞}, for various history matched months for Well API# 42-251-30343 (Barnett shale)

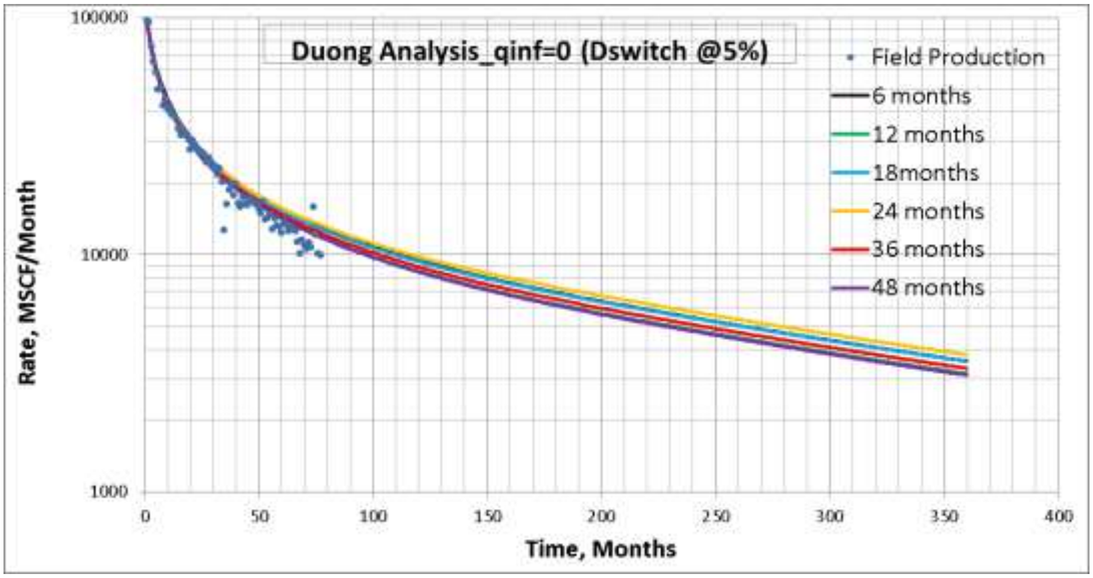

Figure 23- Production forecast comparisons, assuming q_∞=0 for various history matched months for Well API# 42-251-30343 (Barnett shale)

Therefore based on the statistics and production plots it can be said that even though q_∞ provides us with better fits for field wells what needs to be seen is the comparison of the forecast with longer field histories. The conundrum of whether q_∞ should be set equal to zero can only be resolved only by using simulation at this time.

3.4 Accuracy of the Duong model for simulated data

To focus now on whether the Duong method works accurately for longer well histories it was imperative to run simulations that could provide us with longer histories. As mentioned above simulations were run for 2 shale plays, Barnett and Marcellus, whose properties were obtained 133874(Chong et al. 2010), 146876(Cipolla et al. 2011), 144357(Strickland et al. 2011), 96917(Frantz et al. 2005), 125530(Cipolla et al. 2010) ,147603(Ehlig-Economides and Economides 2011) and 144436 (Thompson et al. 2011). The base case simulation schematics for the Barnett shale and the input parameters are shown in **Fig. 24** and **Table 10** respectively. A composite model was used to simulate the Barnett shale with an inner zone or SRV permeability of 0.0005 md and an outer zone permeability of 0.0001 md. The fracture spacing is 800ft & reservoir dimensions are 4000ftx2640ft.A dimensionless fracture conductivity of 2000 was used in the base case. The fracture half lengths are made to be equal for all stages and in the base case the half-length is 150ft.

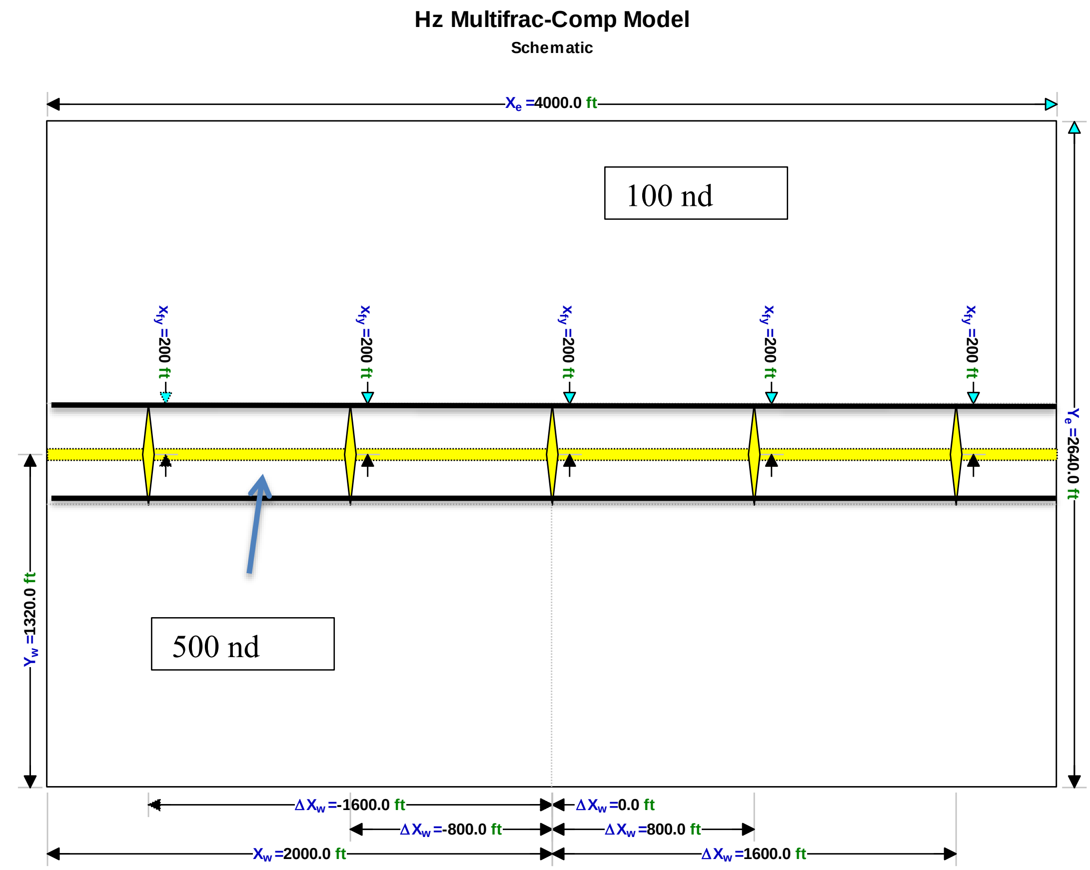

Figure 24- Base case horizontal multi-frac composite model of the Barnett shale

Table 10- Simulation input properties for the Barnett shale

Inner zone Permeability (k_1)	0.0005 md	Effective Horizontal Well Length (X) (L_{ex})	4000.0 ft
Outer zone Permeability (k_2)	0.0001 md	Reservoir Length (X_e)	4000.0 ft
Number of Fractures (#Fracs)	5	Reservoir Width (Y_e)	2640.0 ft
Fracture Half Length (x_{fy})	200 ft	Well Location in X-direction (X_w)	2000.0 ft
Dimensionless Fracture Conductivity (F_{CD})	2000.000	Well Location in Y-direction (Y_w)	1320.0 ft

Reservoir Parameters

Initial Pressure (p_i)	3800.00 psi(a)	Net Pay (h)	250.0 ft
Reservoir Temperature (T_R)	200.0 °F	Total Porosity (ϕ_t)	3.00 %
		Wellbore Radius (r_w)	0.365 ft
Dimensionless Storage 1 (C_{D1})			
Dimensionless Storage 2 (C_{D2})		Drainage Area (A_D)	242 acres
Dimensionless Storage Parameter (C_{pD})			
Turbulence Factor (D)	1/MMscfd	Original Free Gas-In-Place ($OGIP_F$)	12.218 Bscf
		Original Adsorbed Gas-In-Place ($OGIP_A$)	0.000 Bscf
Storativity Ratio (ω)	0.090		
Interporosity Coefficient (λ)	1.5000e-04	Gas Saturation (S_g)	70.00 %
Inter-porosity Skin ($s_{d\phi}$)	0.000	Oil Saturation (S_o)	0.00 %
		Water Saturation (S_w)	30.00 %
		Formation Compressibility (c_f)	8.0138e-06 1/psi
		Total Compressibility (c_t)	1.5390e-04 1/psi
		Gas Compressibility (c_g)	2.0711e-04 1/psi
		Water Compressibility (c_w)	3.0408e-06 1/psi
		Oil Compressibility (c_o)	4.2587e-06 1/psi

Fluid Properties

Reservoir Temperature (T_{resv})	200.0 °F
Reservoir Pressure (p_{resv})	0.0 psi(a)
Gas Gravity (γ_g)	0.650

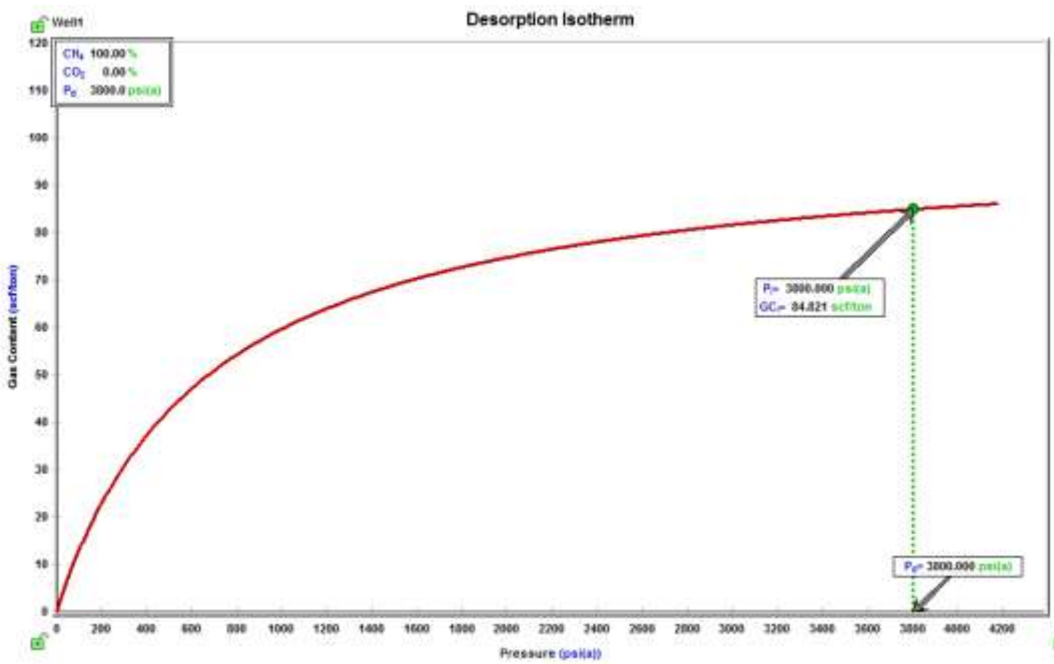

Figure 25- Average desorption curve for the Barnett shale

In **Fig. 25** an average desorption curve was used in the analytical simulator. A Langmuir methane volume of 100 scf/ton and Langmuir methane pressure of 650 psia was used to simulate the effect of desorption. The Langmuir methane volume is the maximum gas content at infinite pressure, and the Langmuir methane pressure is the pressure at which half that gas exists within the shale.

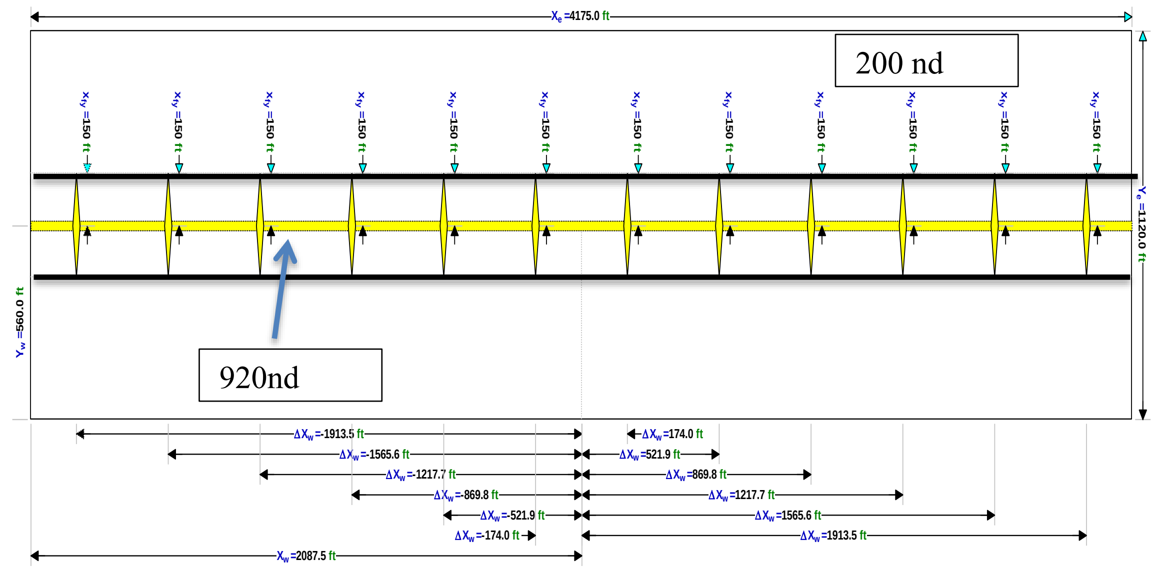

Figure 26- Base case horizontal multi-frac composite model of the Marcellus shale

A composite model was used to simulate the Marcellus shale with an inner zone or SRV permeability of 0.00092 md and an outer zone permeability of 0.0002 md in the base case as seen in **Figure 26**. The input properties for the simulator are provided in **Table 11.** A dimensionless fracture conductivity of 100 was used in the base case. The fracture half lengths are made to be equal for all stages and in the base case the half-length is 150ft. The effect of desorption is described through the isotherm in **Figure 27** where the Langmuir methane volume used is 85 scf/ton and Langmuir methane pressure of 468 psia. It is evident that Marcellus shale has more number of stages and a greater SRV permeability than the Barnett shale.

This may be due partly to more sophisticated fracturing techniques being used for the newer plays like the Marcellus shale compared to the older shales like the Barnett shale.

Table 11- Simulation input properties for the Marcellus shale

Inner zone Permeability (k_1)	0.00092 md	Effective Horizontal Well Length (X) (L_{ex})	4175.0 ft
Outer zone Permeability (k_2)	0.0002 md	Reservoir Length (X_e)	4175.0 ft
Number of Fractures (#Fracs)	12	Reservoir Width (Y_e)	1120.0 ft
Fracture Half Length (x_{fy})	150 ft	Well Location in X-direction (X_w)	2087.5 ft
Dimensionless Fracture Conductivity (F_{CD})	100.000	Well Location in Y-direction (Y_w)	560.0 ft

Reservoir Parameters

Initial Pressure (p_i)	3777.00 psi(a)	Net Pay (h)	150.0 ft
Reservoir Temperature (T_R)	120.0 °F	Total Porosity (ϕ_t)	7.10 %
		Wellbore Radius (r_w)	0.365 ft
Dimensionless Storage 1 (C_{D1})			
Dimensionless Storage 2 (C_{D2})		Drainage Area (A_D)	107 acres
Dimensionless Storage Parameter (C_{pD})			
Turbulence Factor (D)	1/MMscfd	Original Free Gas-In-Place ($OGIP_F$)	8.504 Bscf
		Original Adsorbed Gas-In-Place ($OGIP_A$)	4.305 Bscf
Storativity Ratio (ω)			
Interporosity Coefficient (λ)		Gas Saturation (S_g)	66.20 %
Inter-porosity Skin ($s_{d\phi}$)		Oil Saturation (S_o)	0.00 %
		Water Saturation (S_w)	33.80 %
		Formation Compressibility (c_f)	5.6049e-06 1/psi
		Total Compressibility (c_t)	1.4292e-04 1/psi
		Gas Compressibility (c_g)	1.9968e-04 1/psi
		Water Compressibility (c_w)	2.8199e-06 1/psi
		Oil Compressibility (c_o)	9.3192e-06 1/psi

Fluid Properties

Reservoir Temperature (T_{resv})	120.0 °F
Reservoir Pressure (p_{resv})	psi(a)
Gas Gravity (γ_g)	0.568

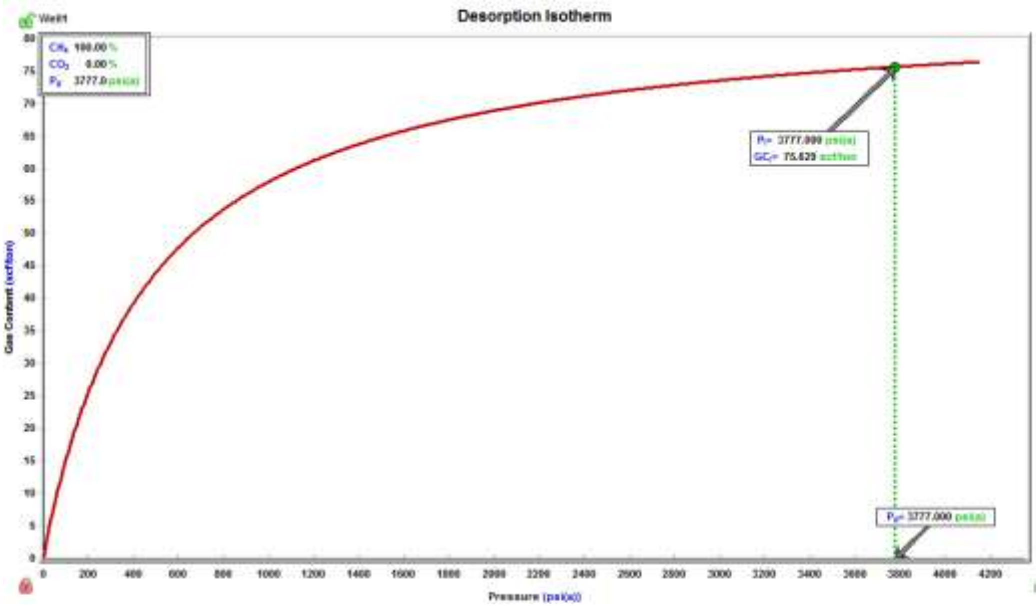

Figure 27- Average desorption isotherm for the Marcellus shale

25 simulations were run for each shale reservoir by changing properties such as fracture half length, fracture spacing, dimensionless fracture conductivity and SRV permeability in accordance with information from various SPE papers. 133874(Chong et al. 2010), 146876(Cipolla et al. 2011), 144357(Strickland et al. 2011), 96917(Frantz et al. 2005), 125530(Cipolla et al. 2010) ,147603(Ehlig-Economides and Economides 2011) and 144436 (Thompson et al. 2011).

The statistics of the discrepancy in remaining reserves is provided in **Table 12** below. The cells shaded yellow show that the Modified Duong method is statistically superior. It is evident that using q_{∞} does not work well for long term production, 30 years in the case of the simulations. Using the Modified Duong method with a Dswitch @5% and q_{∞}=0 works best for various amounts of history matched data. Like the field data the Modified Duong method performs quite well with 18-24 months of history matched data. It is also evident that there is no difference between imposing $q_{\infty=0}$ on the Duong and Modified Duong methods since both give poor and similar results. **Figure 28** shows the variability in forecast for various modifications to the Duong method. As for the field case the Modified Duong with Dswitch of 5% provides the lowest overall discrepancy in remaining reserves. For the well in **Fig.28** BDF begins at 70 months and is one of 25 simulation runs for a Barnett well. **Fig 16** like **Fig.28** also is testament on why switching to Arps (b=0.4 @5% decline rate) and more importantly forcing q∞ to be 0 is necessary to accurately match long term production data.

Table 12- Discrepancy (% error) in remaining reserves for varying months of simulated history matched data

	Error % in remaining reserves				
History Matched		Duong _qinf=0	Duong_qinf≠0	Modified Duong (Dswitch @5%)	Duong_qinf (Dswitch @5%)
6	Mean	21.70	33.09	22.23	86.94
	Std.Dev	19.97	10.84	19.56	6.51
12	Mean	4.44	86.94	5.55	78.03
	Std.Dev	17.71	6.51	17.43	9.36
18	Mean	-6.08	69.42	-4.33	69.42
	Std.Dev	16.24	11.71	16.09	11.71
24	Mean	-0.74	36.20	1.00	35.07
	Std.Dev	13.12	15.26	13.10	15.59
36	Mean	-17.05	45.97	-13.97	45.97
	Std.Dev	9.54	13.26	9.84	13.26
48	Mean	-17.39	33.09	-13.88	33.09
	Std.Dev	8.01	10.84	7.99	10.82

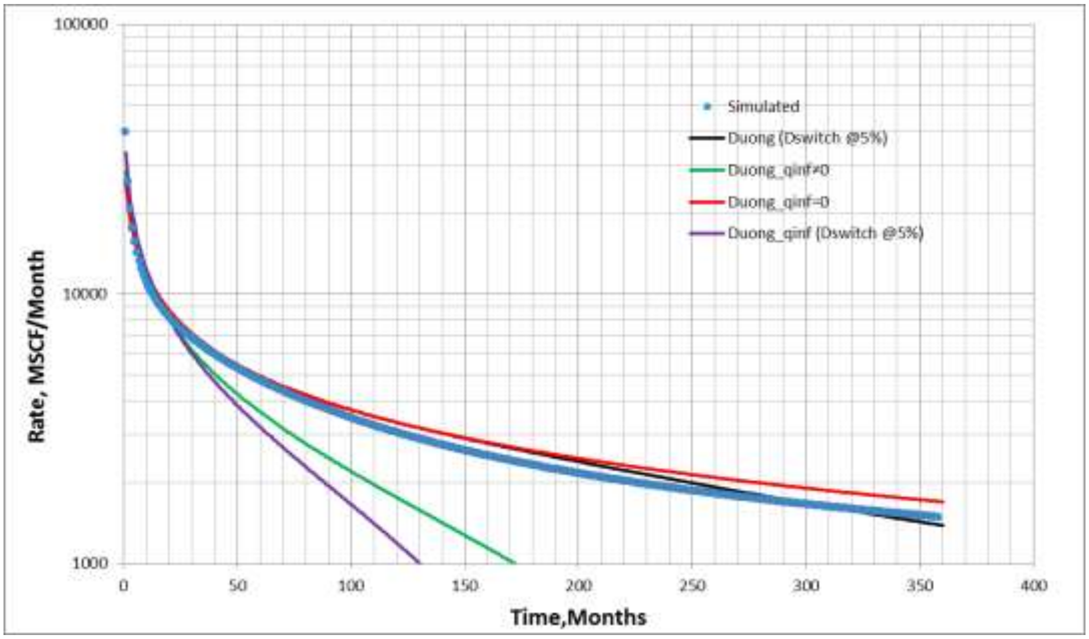

Figure 28- Comparison of various Duong modifications for a Barnett shale simulation

3.5 Accuracy of the Duong model for simulated BDF wells

Until now analysis on BDF wells was performed without analyzing the effect of BDF inside or outside the history match. In the succeeding write up, the effect on the forecast if BDF is excluded in the history match will be observed followed by an analysis when BDF is included in the match.

Since it has been proved above that using the Modified Duong method with q_{∞} =0 and switching to Arps @ 5% is the optimum Duong method amongst the other tested Duong variations, all Duong method forecasts from here on will use this adaptation of the Duong method.

For simulated data it is observed if BDF is not included in the history match the Duong method forecasts are acceptable within a certain level of accuracy. As in the field case as more data is matched the forecasts get better. **Table 13** and **Table 14** show the performance of the Modified Duong method for 18 and 24 months of history matched data. It is observed as more data is matched the Duong method forecast more accurate. **Table 14** clearly shows that the Modified Duong method does an adequate job in forecasting long term BDF for wells where BDF is not included in the history match.

Table 13- Discrepancy (% error) in remaining reserves for 18 months of simulated history matched data where BDF is not included in the history match

18months matched- % error in reserves		
	BDF start time,months	Duong_BF@5%
Marce Case 16	25	-5.79
Barn Case 5	25	-1.97
Barn Case 6	25	-11.43
Marce Case 2	30	-27.08
Barn Case 7	30	-21.12
Barn Case 16	30	0.93
Marce Case 9	35	-10.85
Barn Case 21	35	-1.00
Marce Case 17	40	2.23
Marce Case 19	40	5.68
Barn Case 11	40	10.49
Barn Case 17	40	12.17
Barn Case 25	40	7.87
Barn Case 3	45	-1.48
Barn Case 14	45	15.05
Barn Case 22	45	12.71
Marce Case 6	50	11.33
Marce Case 14	50	8.63
Marce Case 21	50	15.33
Marce Case 24	50	15.19
Marce Case 25	50	15.74
Barn Case 9	50	7.46
Barn Case 18	50	10.36
Barn Case 19	55	17.66
Marce Case 4	60	9.40
Barn Case 1	60	4.96
Barn Case 4	60	18.87
Barn Case 24	60	20.77
Marce Case 12	65	17.60
Barn Case 10	70	22.38
Barn Case 20	70	20.54
Marce Case 22	75	21.99
Marce Case 20	80	20.31
Barn Case 13	80	25.50
Marce Case 13	85	26.77
Barn Case 23	85	27.77
Marce Case 11	90	26.74
Marce Case 15	90	22.41
Marce Case 10	100	28.65
Barn Case 8	100	23.51
Marce Case 7	120	29.98
	Mean	**11.13**
	Std.dev	**13.40**

Table 14- Discrepancy (% error) in remaining reserves for 24 months of simulated history matched data where BDF is not included in the history match

	24months matched- % error in reserves	
	BDF start time,months	Duong_BF@5%
Marce Case 16	25	-9.46
Barn Case 5	25	-6.76
Barn Case 6	25	-12.19
Marce Case 2	30	-21.28
Barn Case 7	30	-17.58
Barn Case 16	30	-9.89
Marce Case 9	35	-11.82
Barn Case 21	35	-10.62
Marce Case 17	40	-4.27
Marce Case 19	40	-1.66
Barn Case 11	40	1.73
Barn Case 17	40	1.96
Barn Case 25	40	-2.53
Barn Case 3	45	2.10
Barn Case 14	45	5.68
Barn Case 22	45	2.12
Marce Case 6	50	2.12
Marce Case 14	50	0.97
Marce Case 21	50	6.17
Marce Case 24	50	6.34
Marce Case 25	50	6.57
Barn Case 9	50	0.91
Barn Case 18	50	1.24
Barn Case 19	55	9.85
Marce Case 4	60	3.86
Barn Case 1	60	7.87
Barn Case 4	60	9.89
Barn Case 24	60	11.61
Marce Case 12	65	8.25
Barn Case 10	70	13.44
Barn Case 20	70	12.98
Marce Case 22	75	13.24
Marce Case 20	80	12.72
Barn Case 13	80	16.79
Marce Case 13	85	18.36
Barn Case 23	85	20.08
Marce Case 11	90	18.34
Marce Case 15	90	15.11
Marce Case 10	100	20.57
Barn Case 8	100	20.56
Marce Case 7	120	22.71
	Mean	**4.54**
	Std.dev	**11.03**

From the above two tables as more data is matched the mean of the error/discrepancy in remaining reserves decreases while the standard deviation that, signifies the range or distribution of errors, also decreases.

Now the accuracy of the Duong method, if BDF is included in the history match, will be checked. In **Table 15**, 48 months of data was used to history match where BDF was included in the match. The mean error and standard deviation of the discrepancy in remaining reserves is high. It is evident that if BDF is included in the history match the forecasts over a 30 Yr. period are poor with only some cases that provided good forecasts. Therefore I recommend that the Modified Duong method not be used to history match data where BDF is included in the match. To dig deeper on how the time at which BDF occurs affects the forecast the Duong forecasts will be applied to groups of wells. The first group consists of wells where BDF begins before 50 months and the other if BDF begins after 50 months.

Table 15- Discrepancy (% error) in remaining reserves for 48 months of history matched data where BDF is included in the match

48months matched- Discrepancy in remaining reserves		
	BDF start time,months	Modified Duong (Dswitch@5%)
Marce Case 23	15	-12.88
Barn Case 2	17	-3.02
Marce Case 1	18	-12.08
Marce Case 8	18	-1.70
Marce Case 18	18	-3.59
Marce Case 3	20	-34.23
Marce Case 5	20	-22.74
Barn Case 12	20	-9.74
Barn Case 15	20	-6.96
Marce Case 16	25	-15.53
Barn Case 5	25	-13.86
Barn Case 6	25	-15.07
Marce Case 2	30	-16.35
Barn Case 7	30	-14.91
Barn Case 16	30	-32.20
Marce Case 9	35	-17.34
Barn Case 21	35	-31.37
Marce Case 17	40	-16.78
Marce Case 19	40	-16.60
Barn Case 11	40	-15.48
Barn Case 17	40	-25.01
Barn Case 25	40	-24.09
Barn Case 3	45	-15.54
Barn Case 14	45	-14.38
Barn Case 22	45	-25.42
	Mean	**-16.67**
	Std.dev	**8.63**

It has been observed as seen in **Table 16** that if 6 to 12 months of data is used for history matches and forecast wells where BDF begins after 50 months, the Modified Duong method performs poorly, but when matched data is greater than 12 months, the Modified Duong works well in forecasting BDF occurring after 50 months. For many of the older wells in the Barnett shale, the occurrence of BDF, if any, takes place after 50 months, therefore **Table 16** is effective in answering how the Duong forecasts for BDF wells in the Barnett shale.

Table 16- Discrepancy (% error) in remaining reserves where BDF begins after 50 months

		Modified Duong- Discrepancy in remaining reserves				
	BDF start time,months	6 months matched	12 months matched	18 months matched	24 months matched	36 months matched
Marce Case 6	50	32.65	11.33	-1.79	2.12	-16.45
Marce Case 14	50	26.18	8.63	-2.67	0.97	-15.61
Marce Case 21	50	34.90	15.33	2.91	6.17	-13.11
Marce Case 24	50	33.86	15.19	3.19	6.34	-12.54
Marce Case 25	50	35.25	15.74	3.34	6.57	-12.80
Barn Case 9	50	20.43	7.46	-2.14	0.91	-17.58
Barn Case 18	50	27.56	10.36	-1.72	1.24	-20.24
Barn Case 19	55	32.60	17.66	7.16	9.85	-10.54
Marce Case 4	60	31.09	9.40	-1.44	3.86	-8.88
Barn Case 1	60	-4.25	4.96	3.81	7.87	-5.56
Barn Case 4	60	36.21	18.87	7.12	9.89	-12.07
Barn Case 24	60	38.72	20.77	8.80	11.61	-10.69
Marce Case 12	65	37.20	17.60	5.14	8.25	-11.59
Barn Case 10	70	39.55	22.38	10.95	13.44	-5.78
Barn Case 20	70	35.28	20.54	10.32	12.98	-7.16
Marce Case 22	75	39.67	21.99	10.50	13.24	-6.42
Marce Case 20	80	35.35	20.31	10.13	12.72	-5.39
Barn Case 13	80	42.13	25.50	14.44	16.79	-2.46
Marce Case 13	85	43.86	26.77	15.77	18.36	-1.19
Barn Case 23	85	43.81	27.77	17.27	20.08	-0.32
Marce Case 11	90	43.77	26.74	15.76	18.34	-1.18
Marce Case 15	90	36.80	22.41	12.62	15.11	-2.78
Marce Case 10	100	45.15	28.65	18.04	20.57	1.41
Barn Case 8	100	31.04	23.51	17.67	20.56	6.69
Marce Case 7	120	44.79	29.98	20.31	22.71	4.73
	Mean	**34.54**	**18.79**	**8.22**	**11.22**	**-7.50**
	Std.dev	**10.15**	**7.12**	**7.17**	**6.74**	**7.00**

In some of the newer shale plays like the Fayetteville, Haynesville and even some wells in the Barnett it is observed that BDF begins before 50 months so it would be interesting to know how the Modified Duong performs when BDF begins before 50 months. In **Table 17** it is evident that for 6-12 of history matched data the Modified Duong performs better for wells where BDF begins before 50 months than for wells where BDF begins after 50 months. It is evident from the below table and previous comparisons that the Duong provides accurate results for 18-24 months of matched data irrespective of the flow regime occurring within the match or after the match.

Table 17- Discrepancy (% error) in remaining reserves where BDF begins before 50 months

		Modified Duong- Discrepancy in remaining reserves				
	BDF start time,months	6 months matched	12 months matched	18 months matched	24 months matched	36 months matched
Marce Case 23	15	-44.86	-28.50	-25.05	-15.07	-18.94
Barn Case 2	17	4.01	-19.37	-24.57	-10.29	-12.11
Marce Case 1	18	15.94	-9.40	-20.31	-10.26	-18.76
Marce Case 8	18	1.27	-20.92	-24.94	-10.18	-11.00
Marce Case 18	18	0.17	-20.96	-25.40	-11.43	-12.67
Marce Case 3	20	-3.37	-35.42	-49.60	-36.63	-45.73
Marce Case 5	20	5.68	-23.13	-35.55	-23.75	-32.16
Barn Case 12	20	14.71	-9.24	-19.25	-9.23	-16.61
Barn Case 15	20	12.92	-11.78	-20.69	-9.16	-14.69
Marce Case 16	25	14.31	-5.79	-16.55	-9.46	-20.11
Barn Case 5	25	21.87	-1.97	-14.21	-6.76	-18.56
Barn Case 6	25	1.90	-11.43	-18.83	-12.19	-19.77
Marce Case 2	30	-19.42	-27.08	-30.06	-21.28	-23.21
Barn Case 7	30	-11.22	-21.12	-25.68	-17.58	-21.18
Barn Case 16	30	23.68	0.93	-14.00	-9.89	-31.83
Marce Case 9	35	-2.25	-10.85	-16.90	-11.82	-20.22
Barn Case 21	35	19.03	-1.00	-14.56	-10.62	-31.05
Marce Case 17	40	20.59	2.23	-9.05	-4.27	-18.60
Marce Case 19	40	24.02	5.68	-5.84	-1.66	-17.38
Barn Case 11	40	30.76	10.49	-2.19	1.73	-15.56
Barn Case 17	40	31.80	12.17	-1.12	1.96	-21.04
Barn Case 25	40	30.08	7.87	-6.42	-2.53	-23.32
Barn Case 3	45	-11.81	-1.48	-2.40	2.10	-11.94
Barn Case 14	45	34.80	15.05	2.39	5.68	-13.02
Barn Case 22	45	33.20	12.71	-1.02	2.12	-21.37
	Mean	**9.91**	**-7.69**	**-16.87**	**-9.22**	**-20.43**
	Std.dev	**19.03**	**14.29**	**12.21**	**9.34**	**7.84**

CHAPTER IV

COMPARISON OF VARIOUS EMPRICAL DECLINE MODELS

4.1 Comparing various empirical models using field data

Now that it has been established using field and simulated data that the Modified Duong, forcing q_{∞} to be zero, with a switch to Arps (b=0.4) at 5% decline is the optimum Duong variation amongst the tested Duong variations, a comparison between Duong and other empirical decline models can give us an insight into which is the best decline curve model to be used for shale gas reservoirs. A similar analysis using field and simulated data will be performed, as above, comparing the Modified Duong, Arps (D_{min}@5%) and the SEDM to ascertain the model that provides us with the lowest discrepancy in remaining reserves. In **Table 18** a comparison of 3 empirical decline models along with the statistics of the discrepancy in remaining reserves is shown. The model whose cell is shaded yellow is statistically superior to the other models. It is clearly evident from **Table 18** the Modified Duong is the best model for all periods of history matched data except for 6 months where the Arps has better statistics.

Table 18- Comparison of the Modified Duong, SEDM and Arps (Dmin @5%) for a field data set

	Discrepancy (error %) in remaining reserves for a field dataset			
History Matched		Duong_Dswitch@5%	SEDM	Arps (Dmin 5%)
6	Mean	-15.98	40.91	10.97
	Std.Dev	29.24	39.06	33.16
	% Wells <15 % error	45.60	22.00	43.20
12	Mean	-7.77	6.44	5.04
	% Wells <15 % error	17.48	27.75	22.57
		66.80	48.40	63.20
18	Mean	-6.90	5.06	3.03
	Std.Dev	14.41	21.90	19.01
	% Wells <15 % error	71.60	59.20	69.20
24	Mean	-2.49	4.49	2.21
	Std.Dev	16.13	20.51	18.92
	% Wells <15 % error	72.80	64.40	71.60
36	Mean	-5.04	4.41	2.77
	Std.Dev	17.88	21.93	22.54
	% Wells <15 % error	71.93	64.91	68.86
48	Mean	-5.45	1.63	-0.05
	Std.Dev	18.08	27.12	26.99
	% Wells <15 % error	77.16	69.04	77.66

As mentioned earlier when analyzing the Duong method, the standard deviation in the above tables is the distribution of the error/discrepancy in remaining reserves between a model and historical data. Therefore if a certain model does not match the wells in a dataset set precisely, then the standard deviation will be high. But if the model does match a dataset precisely but not accurately then the standard deviation will be low and mean would be high. Therefore for a model to be acceptable, the mean and standard deviation of the error/discrepancy in remaining reserves should be small.

The Modified Duong method has a low blend of mean and standard deviation of the error in remaining reserves which implies the Duong has better accuracy and precision than other models in forecasting gas production. Even though for some cases the Modified Duong method has a higher mean error than the other models, the standard deviation which describes the range of error, is much less than the other models. Therefore effectively the Modified Duong turns out to be better. Also in this study it has been assumed a model with an absolute error, in remaining reserves, of less than 15% will count as an acceptable match. In the above table the Modified Duong method has the highest percentage of wells with less than 15% absolute error/discrepancy, in remaining reserves, for any amount of history matched. Therefore this complemented by the a low blend of mean and standard deviation of the error in remaining reserves leads to the fact that the Modified Duong method is the best model that has the potential to provide consistent and more accurate forecasts than other models even though there is a level of discrepancy/error associated with it.

Similar to the analysis performed for the Duong method it would be essential to see how the various empirical methods behave for various counties. It would be notable to see how these models behave in the Tarrant county where it was claimed above that in the year 2007-2008 there was a major shift in production, as in **Fig. 19**, which might have been caused by line pressure changes. **Table 19a-c** compares the performance of the Modified Duong method, Modified Arps (Dmin@5%) method and SEDM. As before, the cells shaded yellow are statistically more accurate and the model that corresponds to the yellow cells is the best model. It is clearly evident the Modified Duong method works for majority of the situations especially for early time situations.

Table 19a. - County wide discrepancy (% error) in remaining reserves comparisons for varying months of history matched data for the Modified Duong model

History Matched	Statistics	Wise	Tarrant	Johnson	Denton	VanBuren
6	Mean	-14.00	-15.28	-17.06	-5.04	-30.39
	Std.Dev	48.08	30.78	28.02	15.12	17.33
	% Wells <15 % error	52	34	50	72	18
12	Mean	-4.07	-9.09	-7.52	-3.41	-15.06
	Std.Dev	16.50	23.98	18.48	12.86	10.86
	% Wells <15 % error	78	48	62	86	60
18	Mean	-3.91	-8.74	-8.27	-4.92	-9.35
	Std.Dev	14.35	20.12	15.79	10.11	8.67
	% Wells <15 % error	74	52	68	90	76
24	Mean	-4.62	-9.56	-7.18	-5.98	-8.60
	Std.Dev	19.56	18.47	19.68	9.33	10.83
	% Wells <15 % error	76	52	70	86	80
36	Mean	-7.09	-4.97	-2.81	-3.10	-4.72
	Std.Dev	12.16	17.64	24.38	7.96	16.81
	% Wells <15 % error	76	65	42	96	76
48	Mean	-7.85	-5.89	-5.13	-3.17	-1.24
	Std.Dev	8.56	21.87	28.27	7.26	6.28
	% Wells <15 % error	80	56	62	94	100

Table 19b. - County wide discrepancy (% error) in remaining reserves comparisons for varying months of history matched data for the (Arps Dmin@ 5%) model

History Matched	Statistics	Wise	Tarrant	Johnson	Denton	VanBuren
6	Mean	11.73	16.41	10.28	10.42	6.05
	Std.Dev	27.84	31.18	46.32	32.93	22.79
	% Wells <15 % error	44.00	42.00	20.00	64.00	46.00
12	Mean	7.61	3.36	7.86	1.07	5.30
	Std.Dev	21.12	25.71	31.39	15.85	14.26
	% Wells <15 % error	66.00	46.00	46.00	86.00	72.00
18	Mean	6.70	2.27	0.40	1.78	4.04
	Std.Dev	17.84	22.20	24.31	16.76	11.46
	% Wells <15 % error	80.00	48.00	44.00	90.00	84.00
24	Mean	3.66	0.95	4.41	1.07	0.87
	Std.Dev	18.56	19.93	28.12	10.77	12.31
	% Wells <15 % error	82.00	56.00	56.00	84.00	80.00
36	Mean	-2.31	3.16	9.98	2.02	-1.11
	Std.Dev	13.58	23.73	34.07	8.30	22.80
	% Wells <15 % error	90.00	50.00	46.00	94.00	60.71
48	Mean	-5.48	0.08	4.81	0.69	0.94
	Std.Dev	25.19	40.22	25.86	6.45	23.09
	% Wells <15 % error	88.00	66.00	50.00	94.00	66.67

Table 19c. - County wide discrepancy (% error) in remaining reserves comparisons for varying months of history matched data for the SEDM model

History Matched	Statistics	Wise	Tarrant	Johnson	Denton	VanBuren
6	Mean	50.43	48.45	33.48	29.11	43.68
	Std.Dev	37.24	36.61	45.58	39.72	31.40
	% Wells <15 % error	22.00	14.00	18.00	40.00	16.00
12	Mean	3.39	1.31	15.69	8.51	2.92
	Std.Dev	28.97	35.08	29.03	23.74	17.25
	% Wells <15 % error	58.00	30.00	38.00	58.00	58.00
18	Mean	4.16	0.31	8.76	6.49	5.44
	Std.Dev	24.02	25.05	24.33	20.48	13.44
	% Wells <15 % error	60.00	42.00	48.00	74.00	72.00
24	Mean	1.88	-0.78	11.27	6.54	3.23
	Std.Dev	23.33	23.08	24.99	12.94	13.32
	% Wells <15 % error	72.00	54.00	44.00	78.00	74.00
36	Mean	-3.06	2.50	14.52	5.22	0.62
	Std.Dev	17.94	22.01	29.85	9.33	22.12
	% Wells <15 % error	72.00	56.00	44.00	90.00	60.71
48	Mean	-5.46	0.54	8.03	3.67	3.96
	Std.Dev	27.78	38.07	25.59	7.09	25.23
	% Wells <15 % error	76.00	56.00	42.00	92.00	50.00

Figure 29 is a precise representation of the behavior of the 3 models for short term data. As seen in **Fig.29** the Modified Duong method works the best with the lowest discrepancy in remaining reserves followed by the Arps (Minimum Decline) model. It has been observed the SEDM model tends to drastically underestimate the EUR for shorter history matches (<12 months). As observed in **Table 18** and **Table 19 a-c,** the Modified Duong method usually works the best, for short term data.

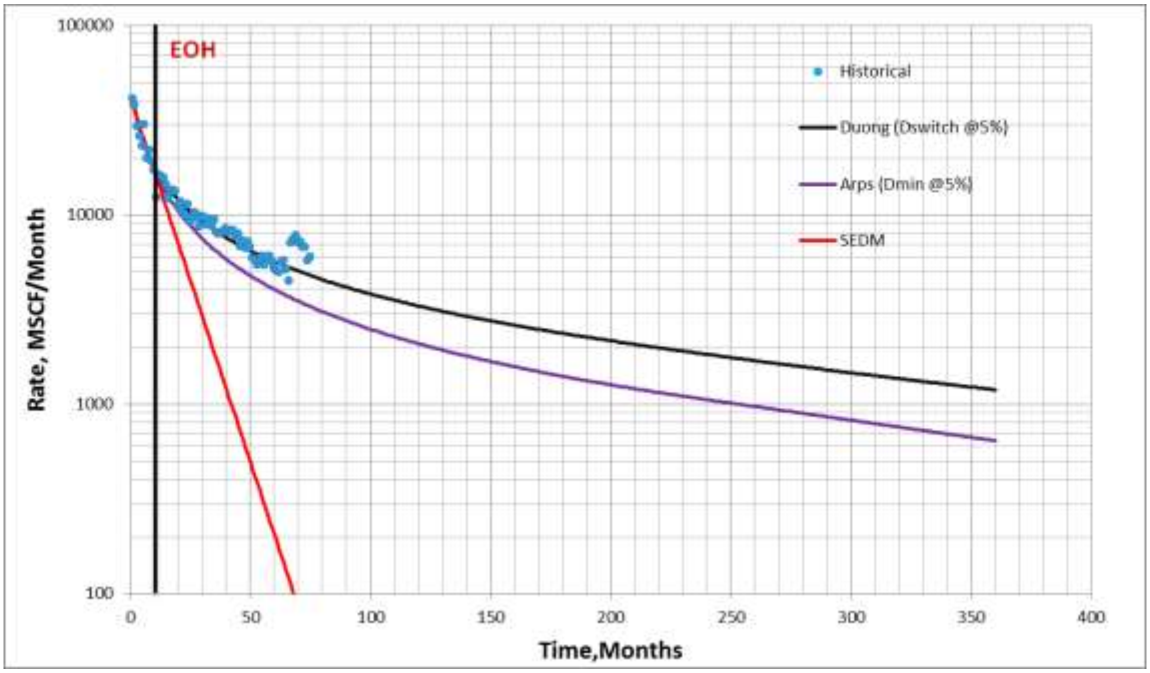

Figure 29- Comparison of various empirical models for API# 42-121-32245, matching 12 months of historical data

Figure 30 and **Figure 31**are representative of how the three empirical models behave for long term history (>3 years). The forecasts are somewhat similar but statistically the Modified Duong method is the best model. Complementing **Fig.30 and Fig. 31** is **Table 18** and **Table 19 a-c** which is proof to the fact that for history matched data more than three years the forecasts of the three models are comparable with the Modified Duong proving to be the best model in majority of the cases. It would be interesting to see if these models hold true for longer production histories and at this point of time it can only be proved using simulations which will be examined at in the coming sections.

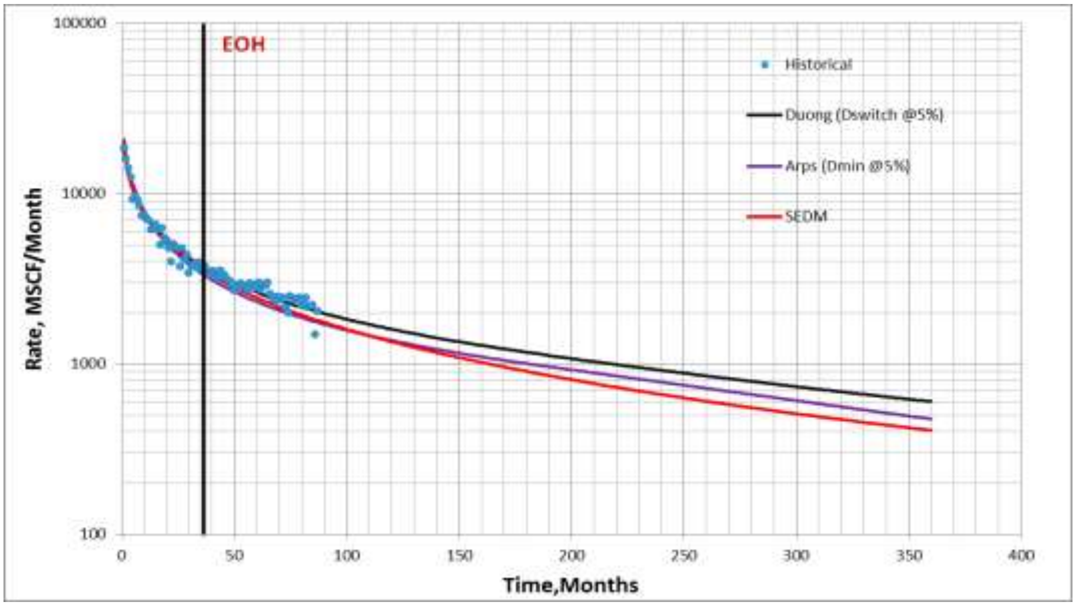

Figure 30- Comparison of various empirical models for API# 42-497-35453, matching 36 months of historical data

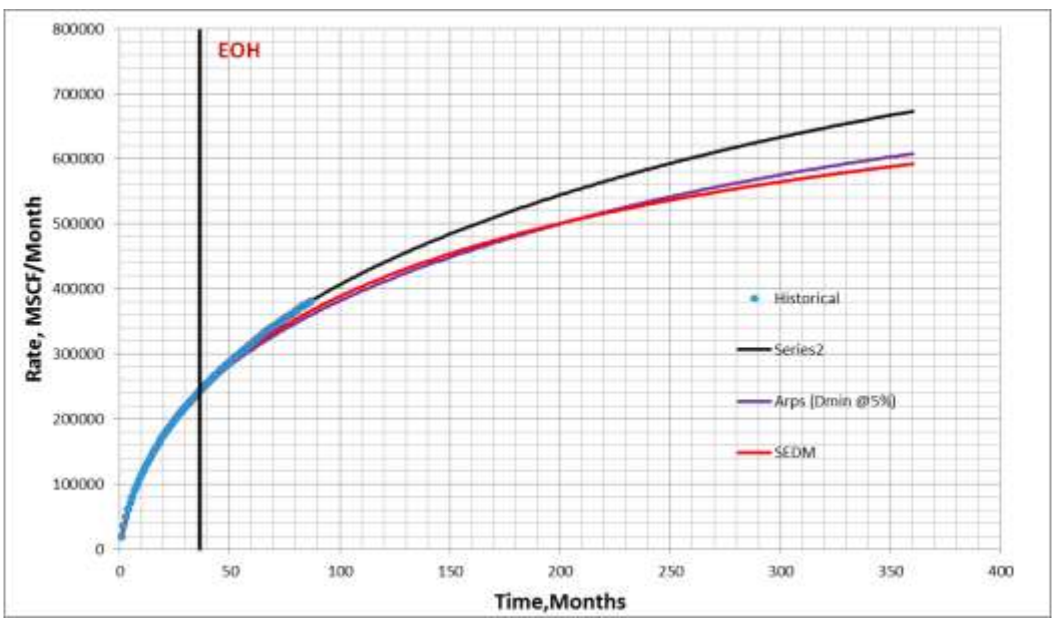

Figure 31- Cumulative production comparisons of various empirical models for API# 42-497-35453, matching 36 months of historical data

4.2 Comparing various empirical models for field BDF wells

In this section the 3 models will be compared for their accuracy to match and forecast field BDF wells. **Table 20** is an extension to **Table 9,** in chapter III, where columns for SEDM and Arps (Dmin @5%) are inserted.

Table 20- Discrepancy (% error) in remaining reserves for the 3 empirical methods on field BDF wells

		Discrepancy in remaining reserves for BDF wells (BDF excluded in history match)				
History Matched	**No.of Wells**	**Statistics**	**Duong_Dswitch@5%**	**Duong_qinf_Dswitch@5%**	**SEDM**	**Arps (Dmin @ 5%)**
6	**47**	Mean	-38.96	-19.12	42.77	2.16
		Std.Dev	45.40	60.25	35.23	34.21
12	**47**	Mean	-19.90	-8.19	4.09	2.20
		Std.Dev	19.40	24.56	32.81	25.28
18	**47**	Mean	-14.11	-6.92	5.88	2.42
		Std.Dev	16.62	17.94	24.20	20.32
24	**47**	Mean	-13.25	-7.77	2.09	-1.10
		Std.Dev	20.99	15.91	22.67	21.56
36	**41**	Mean	-8.50	-7.37	2.47	-0.77
		Std.Dev	15.35	14.56	17.00	17.35
48	**33**	Mean	-10.52	-10.77	1.18	-1.22
		Std.Dev	14.94	16.03	17.99	17.01

It was established in Chapter III that for field BDF wells using a Modified Duong with a non-zero q_∞ and a D_{switch} of 5% works better than a Modified Duong with q_∞=0 and a Dswitch of 5% as observed in **Table 9** and **Table 20**. But from the simulations in Chapter III it was found out that forcing q_∞ to be zero works better for longer histories. The extreme effect of using q_∞ for early histories has also been established. But in **Table 20** it is shown that the Arps method with a Dmin of 5% is the best model to match and forecast BDF wells especially for 6-12 months of production data. If more than 24 months of data is history matched the 3 models behave similarly with the Arps (Dmin @5%) resulting to be the best model. **Fig. 32** shows the behavior of the three models with 12 months history matched while **Fig. 33** compares the behavior of the three models with 36 months history matched. In the Wise county well shown in **Fig.32** and **Fig.33** BDF begins at 30 months.

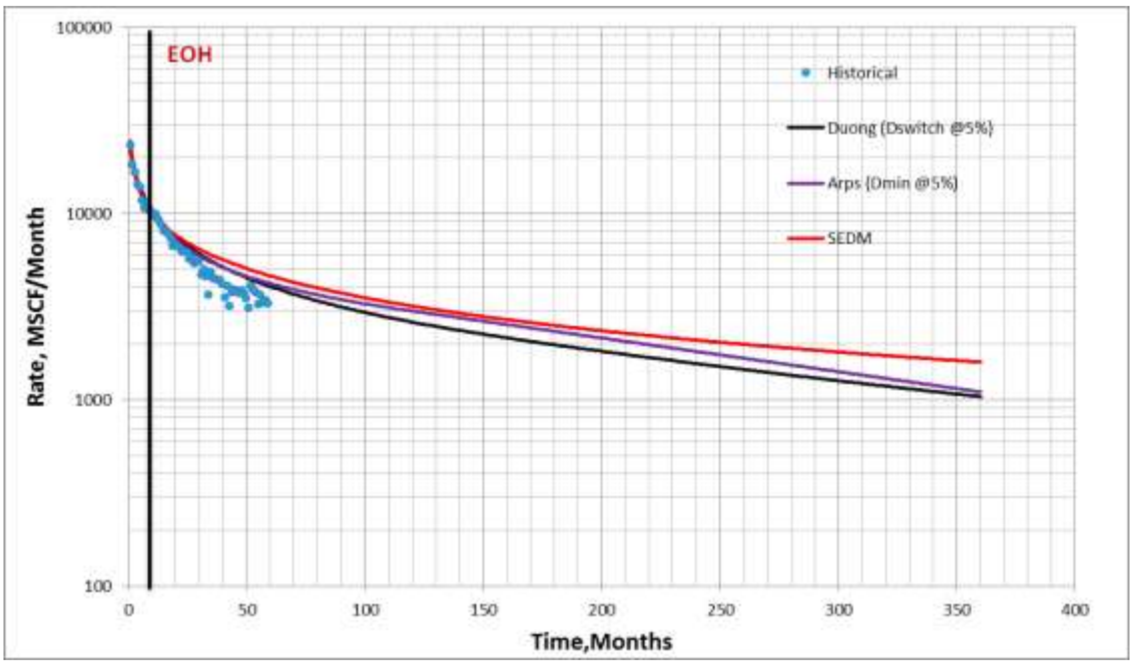

Figure 32- Comparing various empirical models for a BDF well (API# 42-497-35968), matching 12 months of historical data

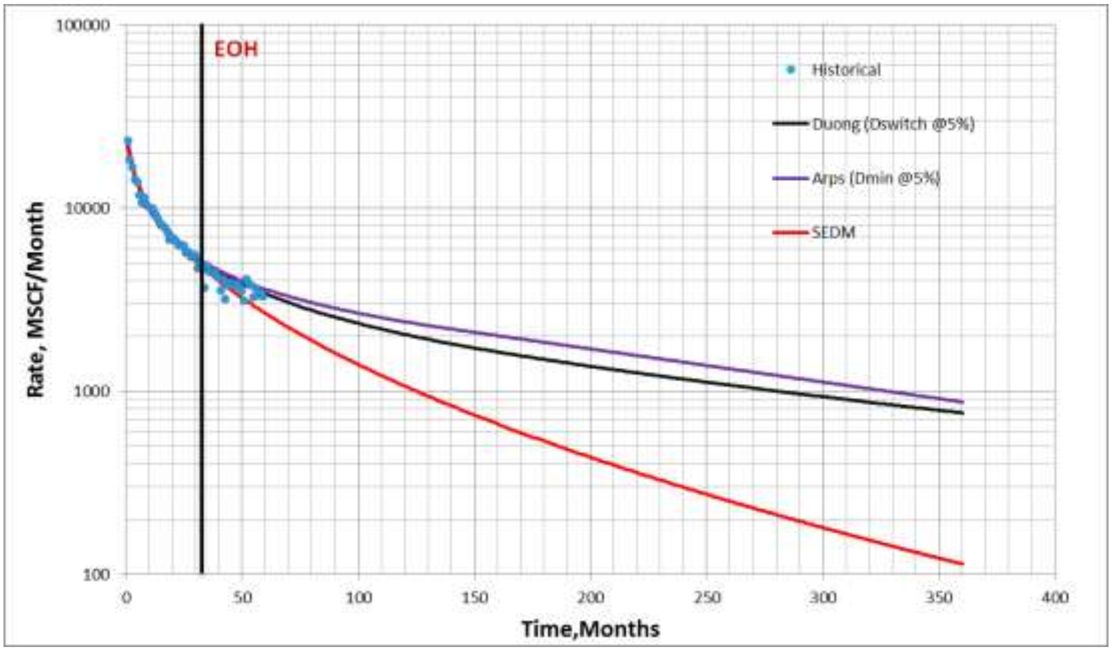

Figure 33- Comparing various empirical models for a BDF well (API# 42-497-35968), matching 36months of historical data

For early time data **Fig.32** shows that none of the models can project BDF with 12 months of matched data but in **Fig.33** it is evident that all models tend to prognosticate the available BDF data. It is also surprising to see the variation in forecasts, in **Fig 33**, between the models since the SEDM tends to overtly under predict the EUR compared to the Modified Duong method and Modified Arps (Dmin@5%).

The field wells have a maximum of 83 months of production data of which only 15-25 months of BDF is present in the history of these BDF wells. Therefore it is imperative to run long term simulations to establish a certain model as the optimum model for BDF wells.

4.3 Comparing various empirical models for simulated wells

Similar to the analysis for the Duong method, a comparison of the three empirical models will be performed using simulations similar in design to **Fig.24** and **Fig.26.** The formation properties too are similar to **Table 10** and **Table 11** while the desorption properties identical to the isotherms in **Fig 25** and **Fig 27.**

The discrepancy/error in remaining reserves for the 50 simulations is shown in **Table 21.** It is evident at early times (6 months) the Modified Arps (Dmin 5%) works the best. In comparison to the results of the field data the simulated data closely parallels the trend of the comparisons of the field data. Similar to the field comparisons none on the models work accurately for shorter matched histories, even though the Modified Arps method performs the best with the lowest mean and standard deviation in the discrepancy/error of remaining reserves. For rest of the matched histories (12-48 months) the Modified Duong method turns out to be the best model except for the case of 36 months where the SEPD and the Duong have similar statistics. Like for the field data it can be ∞erred that the Modified Duong works extremely well for matched histories between 18 -24 months. The Modified Arps (Dmin 5%) method and the SEDM forecasts get better as more history is matched. A true representation of **Table 21** is graphically shown in **Fig. 34** and **Fig. 35.**

Table 21- Comparison of the discrepancy (% error) in remaining reserves for the Modified Duong, SEDM and Arps for a simulated data set

		Error % in remaining reserves		
History Matched		Duong_qinf=0 (Dswitch @5%)	Arps (Dmin @ 5%)	SEPD
6	Mean	22.23	-12.38	38.62
	Std.Dev	19.56	19.80	14.39
12	Mean	5.55	-15.17	22.37
	Std.Dev	17.43	20.98	17.96
18	Mean	-4.33	-18.27	21.40
	Std.Dev	16.09	21.16	19.36
24	Mean	1.00	-18.64	14.96
	Std.Dev	13.10	18.47	18.31
36	Mean	-13.97	-16.79	10.32
	Std.Dev	9.84	13.31	16.24
48	Mean	-13.88	-13.75	10.41
	Std.Dev	7.99	10.81	18.72

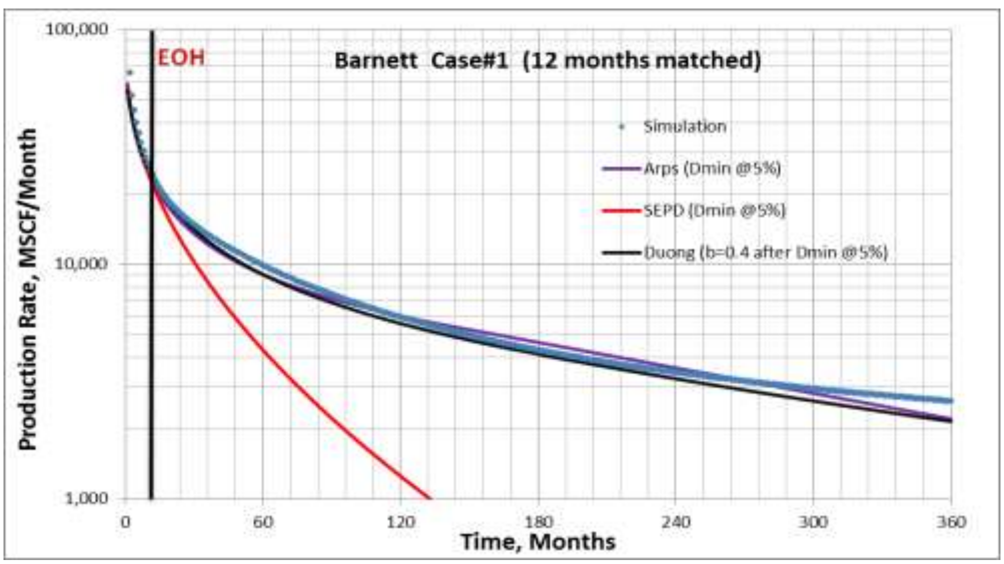

Figure 34- Comparing various empirical models for a Barnett simulation matching 12months of historical data

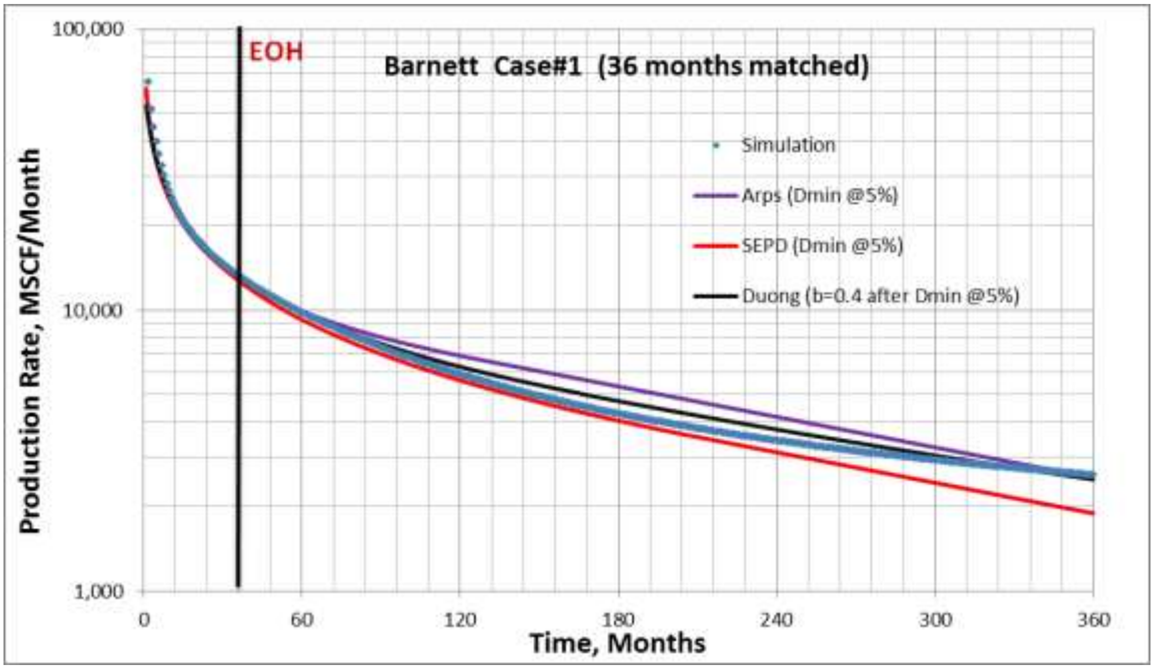

Figure 35- Comparing various empirical models for a Barnett simulation matching 36months of historical data

For shorter periods as seen in **Fig 34** the SEPD like for the field data tends to highly underestimate the historical data. In **Fig.35** it is observed that for greater than 36 months of data all the 3 models behave similarly even though the Duong tends to give a more accurate representation of the true EUR.

4.4. Comparing various empirical models for simulated BDF wells

In the succeeding write up, the effect on the forecast if BDF is excluded in the history match will be observed followed by an analysis if BDF is included in the match. In **Table 20** it was shown that for field BDF wells using a q_{∞} works better than forcing q_{∞} to be 0, but above in **Table 12** it was shown that for longer history periods using a Modified Duong method or even the original Duong method with a q_{∞} value, the average mean of the discrepancy in remaining reserves is very high. Therefore for the below simulations the SEDM and Arps (Dmin @5%) will be compared with the Modified Duong method (Dswitch @5%) and $q\infty$ =0, since it was proved earlier for longer histories the Modified Duong (Dswitch @5%) with $q\infty$ =0 works better.

In **Table 22** and **Table 23** we see the effect of excluding BDF in the history match. In both the tables it is evident that the Modified Duong method works exceptionally well. The SEDM does a poor job in forecasting production for wells where BDF is excluded in the match. The Arps (Dmin @5%) too does an average job in forecasting production where BDF occurs outside the history match. Only the Modified Duong method performs with an acceptable level of discrepancy for both 18 and 36 months of history matched noted in **Table 22** and **Table 23.**

Table 22- Comparison of the discrepancy (% error) in remaining reserves for 18 months of simulated history matched data where BDF is not included in the history match for various empirical models

	18months matched- % error in remaining reserves			
	BDF start time,months	Modified Duong (Dswitch@5%)	Arps (Dmin @ 5%)	SEPD
Marce Case 1	18	-20.31	-44.80	-2.03
Marce Case 8	18	-24.94	-51.07	64.26
Marce Case 18	18	-25.40	-50.78	62.53
Marce Case 3	20	-35.42	-84.53	-14.06
Marce Case 5	20	-23.13	-64.13	-5.51
Barn Case 12	20	-9.24	-39.17	2.81
Barn Case 15	20	-11.78	-44.74	2.11
Marce Case 16	25	-5.79	-29.70	0.95
Barn Case 5	25	-1.97	-28.80	10.07
Barn Case 6	25	-11.43	-24.50	1.32
Marce Case 2	30	-27.08	-31.80	46.15
Barn Case 7	30	-21.12	-28.93	42.74
Barn Case 16	30	0.93	-29.66	13.73
Marce Case 9	35	-10.85	-15.87	50.08
Barn Case 21	35	-1.00	-28.83	7.72
Marce Case 17	40	2.23	-18.45	7.61
Marce Case 19	40	5.68	-14.85	12.12
Barn Case 11	40	10.49	-11.09	19.65
Barn Case 17	40	12.17	-15.01	23.37
Barn Case 25	40	7.87	-19.22	20.40
Barn Case 3	45	-1.48	-8.55	67.76
Barn Case 14	45	15.05	-5.91	25.00
Barn Case 22	45	12.71	-15.18	25.13
Marce Case 6	50	11.33	-11.85	24.54
Marce Case 14	50	8.63	-10.94	14.19
Marce Case 21	50	15.33	-6.18	25.08
Marce Case 24	50	15.19	-5.53	23.86
Marce Case 25	50	15.74	-5.69	25.62
Barn Case 9	50	7.46	-11.62	12.45
Barn Case 18	50	10.36	-14.41	18.59
Barn Case 19	55	17.66	-4.63	24.07
Marce Case 4	60	9.40	-3.66	16.83
Barn Case 1	60	4.96	1.12	65.65
Barn Case 4	60	18.87	-5.91	28.74
Barn Case 24	60	20.77	-4.45	31.64
Marce Case 12	65	17.60	-3.84	28.20
Barn Case 10	70	22.38	3.73	30.73
Barn Case 20	70	20.54	-1.53	27.21
Marce Case 22	75	21.99	2.23	31.32
Marce Case 20	80	20.31	3.13	25.33
Barn Case 13	80	25.50	7.30	33.87
Marce Case 13	85	26.77	7.62	35.93
Barn Case 23	85	27.77	4.69	38.17
Marce Case 11	90	26.74	7.63	35.96
Marce Case 15	90	22.41	5.82	27.04
Marce Case 10	100	28.65	10.02	37.47
Barn Case 8	100	23.51	11.13	32.78
Marce Case 7	120	29.98	12.79	36.90
	Mean	**6.38**	**-14.97**	**25.34**
	Std.dev	**17.26**	**20.85**	**18.28**

Table 23- Comparison of the discrepancy (% error) in remaining reserves for 36 months of simulated history matched data where BDF is not included in the history match for various empirical models

	36months matched- % error in remaining reserves			
	BDF start time,months	Modified Duong (Dswitch@5%)	Arps (Dmin @ 5%)	SEPD
Marce Case 17	40	-18.6	-26.4	34.6
Marce Case 19	40	-17.4	-22.8	-5.4
Barn Case 11	40	-15.6	-19.0	-1.4
Barn Case 17	40	-21.0	-24.0	-1.8
Barn Case 25	40	-23.3	-28.8	-5.1
Barn Case 3	45	-11.9	-19.4	35.6
Barn Case 14	45	-13.0	-13.6	1.5
Barn Case 22	45	-21.4	-24.3	-2.0
Marce Case 6	50	-16.5	-19.9	37.4
Marce Case 14	50	-15.6	-18.8	-3.7
Marce Case 21	50	-13.1	-13.8	1.7
Marce Case 24	50	-12.5	-13.0	1.1
Marce Case 25	50	-12.8	-13.2	37.3
Barn Case 9	50	-17.6	-19.7	-8.4
Barn Case 18	50	-20.2	-23.2	-5.1
Barn Case 19	55	-10.5	-11.3	2.8
Marce Case 4	60	-8.9	-10.3	37.6
Barn Case 1	60	-5.6	-12.8	6.2
Barn Case 4	60	-12.1	-12.9	4.4
Barn Case 24	60	-10.7	-11.1	7.2
Marce Case 12	65	-11.6	-11.2	3.7
Barn Case 10	70	-5.8	-2.9	6.9
Barn Case 20	70	-7.2	-7.4	5.9
Marce Case 22	75	-6.4	-4.2	7.2
Marce Case 20	80	-5.4	-3.2	36.9
Barn Case 13	80	-2.5	1.3	10.0
Marce Case 13	85	-1.2	2.1	12.3
Barn Case 23	85	-0.3	0.3	14.5
Marce Case 11	90	-1.2	2.1	13.3
Marce Case 15	90	-2.8	0.0	38.2
Marce Case 10	100	1.4	5.0	16.5
Barn Case 8	100	6.7	8.0	11.6
Marce Case 7	120	4.7	8.3	16.1
	Mean	**-9.99**	**-10.91**	**11.14**
	Std.dev	**7.77**	**10.44**	**14.94**

Now the accuracy of Duong, if BDF is included in the history match, will be compared to the other two models. In **Table 24** a comparison between the Modified Duong method (Dswitch @5%), Modified Arps method (Dmin @5%) and the SEDM is shown for wells where BDF is included in the match. Even though the Modified Duong method (Dswitch @5%) provides statistically better results, it is evident in **Table 24** that none of models can accurately forecast production when BDF is included in the history match. To increase the accuracy of the Modified Duong forecasts, if BDF is included in the match, two additional parameters, the Arps switch decline rate &b-factor, could be solved for when history matching. To dig deeper on how the time at which BDF occurs affects the forecast, it is been observed as in **Table 25a-c** that if 6 to 12 months of data is used to history match and forecast wells where BDF begins after 50 months, the Modified Duong method performs poorly but matched data greater than 12 months works well in forecasting BDF occurring after 50 months. Many of the older wells in the Barnett shale, the occurrence of BDF, if any, takes place after 50 months, therefore the **Table 25a-c** is effective in answering how the Duong forecasts BDF wells in the Barnett shale.

Table 24- Comparison of the discrepancy (% error) in remaining reserves for 48months of simulated history matched data, for 3 empirical models, where BDF is included in the history match

	48months matched- Discrepancy in remaining reserves			
	BDF start time,months	Modified Duong (Dswitch@5%)	Arps	SEPD
Marce Case 23	15	-12.88	-1.29	53.99
Barn Case 2	17	-3.02	-9.49	24.79
Marce Case 1	18	-12.08	-15.53	43.94
Marce Case 8	18	-1.70	0.93	55.01
Marce Case 18	18	-3.59	-1.28	52.45
Marce Case 3	20	-34.23	-32.30	6.87
Marce Case 5	20	-22.74	-23.67	43.29
Barn Case 12	20	-9.74	-12.67	13.33
Barn Case 15	20	-6.96	-8.65	18.78
Marce Case 16	25	-15.53	-19.99	35.30
Barn Case 5	25	-13.86	-18.96	2.50
Barn Case 6	25	-15.07	-17.63	28.55
Marce Case 2	30	-16.35	-13.83	15.74
Barn Case 7	30	-14.91	-14.28	27.52
Barn Case 16	30	-32.20	-38.68	-12.35
Marce Case 9	35	-17.34	-19.80	18.24
Barn Case 21	35	-31.37	-37.76	-13.76
Marce Case 17	40	-16.78	-22.13	-3.46
Marce Case 19	40	-16.60	-21.94	-2.78
Barn Case 11	40	-15.48	-19.76	0.27
Barn Case 17	40	-25.01	-26.52	-5.56
Barn Case 25	40	-24.09	-29.72	-5.23
Barn Case 3	45	-15.54	-20.75	-2.76
Barn Case 14	45	-14.38	-14.79	2.27
Barn Case 22	45	-25.42	-26.81	-5.64
	Mean	**-16.67**	**-18.69**	**15.65**
	Std.dev	**8.63**	**10.28**	**21.83**

Table 25a- Discrepancy (% error) in remaining reserves where BDF begins after 50 months for the Modified Duong (Dswitch @5%)

	Modified Duong (Dswitch@ 5%)- Discrepancy(% error) in remaining reserves						
	BDF start time,months	6 months matched	12 months matched	18 months matched	24 months matched	36 months matched	48months matched
Marce Case 6	50	32.65	11.33	-1.79	2.12	-16.45	-16.84
Marce Case 14	50	26.18	8.63	-2.67	0.97	-15.61	-15.87
Marce Case 21	50	34.90	15.33	2.91	6.17	-13.11	-14.98
Marce Case 24	50	33.86	15.19	3.19	6.34	-12.54	-14.49
Marce Case 25	50	35.25	15.74	3.34	6.57	-12.80	-14.79
Barn Case 9	50	20.43	7.46	-2.14	0.91	-17.58	-20.93
Barn Case 18	50	27.56	10.36	-1.72	1.24	-20.24	-24.01
Barn Case 19	55	32.60	17.66	7.16	9.85	-10.54	-15.68
Marce Case 4	60	31.09	9.40	-1.44	3.86	-8.88	-8.53
Barn Case 1	60	-4.25	4.96	3.81	7.87	-5.56	-9.13
Barn Case 4	60	36.21	18.87	7.12	9.89	-12.07	-17.41
Barn Case 24	60	38.72	20.77	8.80	11.61	-10.69	-16.31
Marce Case 12	65	37.20	17.60	5.14	8.25	-11.59	-14.09
Barn Case 10	70	39.55	22.38	10.95	13.44	-5.78	-9.38
Barn Case 20	70	35.28	20.54	10.32	12.98	-7.16	-12.62
Marce Case 22	75	39.67	21.99	10.50	13.24	-6.42	-10.24
Marce Case 20	80	35.35	20.31	10.13	12.72	-5.39	-9.01
Barn Case 13	80	42.13	25.50	14.44	16.79	-2.46	-6.71
Marce Case 13	85	43.86	26.77	15.77	18.36	-1.19	-5.90
Barn Case 23	85	43.81	27.77	17.27	20.08	-0.32	-6.23
Marce Case 11	90	43.77	26.74	15.76	18.34	-1.18	-5.88
Marce Case 15	90	36.80	22.41	12.62	15.11	-2.78	-6.82
Marce Case 10	100	45.15	28.65	18.04	20.57	1.41	-3.54
Barn Case 8	100	31.04	23.51	17.67	20.56	6.69	2.43
Marce Case 7	120	44.79	29.98	20.31	22.71	4.73	-0.26
	Mean	**34.54**	**18.79**	**8.22**	**11.22**	**-7.50**	**-11.09**
	Std.dev	**10.15**	**7.12**	**7.17**	**6.74**	**7.00**	**6.29**

Table.25b- Discrepancy (% error) in remaining reserves where BDF begins after 50 months for the SEDM

		SEDM- Discrepancy (% error) in remaining reserves					
	BDF start time,months	6 months matched	12 months matched	18 months matched	24 months matched	36 months matched	48months matched
Marce Case 6	50	34.90	24.54	14.30	53.16	37.64	0.14
Marce Case 14	50	43.86	14.19	62.18	49.50	-1.19	-2.22
Marce Case 21	50	35.66	25.08	16.61	11.24	3.91	1.41
Marce Case 24	50	39.92	23.86	16.16	10.62	3.41	1.04
Marce Case 25	50	36.33	25.62	17.31	11.52	37.50	1.50
Barn Case 9	50	52.25	12.45	4.58	0.89	-5.29	-8.27
Barn Case 18	50	42.69	18.59	10.56	5.14	-2.89	-7.42
Barn Case 19	55	47.64	24.07	17.74	12.37	5.06	-0.24
Marce Case 4	60	29.21	16.83	9.92	7.16	37.74	4.37
Barn Case 1	60	70.03	65.65	59.57	52.13	7.38	27.56
Barn Case 4	60	43.11	28.74	21.34	14.36	6.37	0.25
Barn Case 24	60	41.45	31.64	23.41	17.80	8.99	1.99
Marce Case 12	65	39.19	28.20	19.40	13.00	5.86	29.08
Barn Case 10	70	40.32	30.73	22.96	17.86	9.37	5.75
Barn Case 20	70	48.36	27.21	21.55	16.49	8.13	2.91
Marce Case 22	75	41.28	31.32	23.02	18.06	9.49	29.21
Marce Case 20	80	49.34	25.33	19.25	14.37	37.06	4.85
Barn Case 13	80	42.07	33.87	25.94	20.75	12.51	8.28
Marce Case 13	85	45.57	35.93	28.32	22.48	14.56	10.34
Barn Case 23	85	46.24	38.17	30.99	25.63	16.27	11.08
Marce Case 11	90	45.60	35.96	28.35	23.00	15.37	10.58
Marce Case 15	90	50.32	27.04	21.29	55.22	38.33	28.15
Marce Case 10	100	46.88	37.47	30.17	25.04	18.43	12.05
Barn Case 8	100	62.74	32.78	21.31	18.52	14.82	11.47
Marce Case 7	120	48.21	36.90	31.70	26.12	18.46	33.07
	Mean	**44.93**	**29.29**	**23.92**	**21.70**	**14.29**	**8.68**
	Std.dev	**8.45**	**10.36**	**12.97**	**15.09**	**13.38**	**11.85**

Like the Modified Duong method results in **Table 25a** the SEDM has a poor performance in forecasting BDF for short history match periods. For longer history match periods the SEDM performs better than shorter periods but still fails to emerge as a reliable model to predict BDF occurring after 50 months.

Table.25c- Discrepancy (% error) in remaining reserves where BDF begins after 50 months for the Arps (Dmin @5%)

		Arps (Dmin @5%)- Discrepancy (% error) in remaining reserves					
	BDF start time,months	6 months matched	12 months matched	18 months matched	24 months matched	36 months matched	48months matched
Marce Case 6	50	-7.47	-11.85	-14.81	-17.13	-19.91	-20.85
Marce Case 14	50	-5.89	-10.94	-13.81	-16.06	-18.78	-19.71
Marce Case 21	50	-3.44	-6.18	-8.78	-10.91	-13.79	-15.11
Marce Case 24	50	-0.69	-5.53	-8.07	-10.18	-13.04	-14.38
Marce Case 25	50	-1.29	-5.69	-8.26	-10.38	-13.24	-14.61
Barn Case 9	50	-8.53	-11.62	-14.07	-16.25	-19.71	-21.95
Barn Case 18	50	-11.45	-14.41	-17.06	-19.45	-23.25	-25.69
Barn Case 19	55	-0.16	-4.63	-6.49	-8.25	-11.26	-13.48
Marce Case 4	60	1.09	-3.66	-6.77	-8.64	-10.28	-10.60
Barn Case 1	60	-13.82	1.12	-2.34	-8.19	-12.83	-12.32
Barn Case 4	60	-2.17	-5.91	-7.88	-9.73	-12.86	-15.16
Barn Case 24	60	2.07	-4.45	-6.32	-8.08	-11.09	-13.33
Marce Case 12	65	-0.33	-3.84	-6.30	-8.35	-11.22	-12.68
Barn Case 10	70	5.91	3.73	1.65	-0.16	-2.86	-4.48
Barn Case 20	70	4.33	-1.53	-3.15	-4.70	-7.41	-9.49
Marce Case 22	75	5.73	2.23	0.20	-1.56	-4.24	-5.88
Marce Case 20	80	6.79	3.13	1.16	-0.54	-3.16	-4.79
Barn Case 13	80	9.19	7.30	5.47	3.84	1.29	-0.37
Marce Case 13	85	9.99	7.62	5.95	4.48	2.11	0.47
Barn Case 23	85	10.09	4.69	3.50	2.35	0.27	-1.43
Marce Case 11	90	9.42	7.63	5.96	4.49	2.12	0.47
Marce Case 15	90	9.21	5.82	4.04	2.50	-0.02	-1.66
Marce Case 10	100	11.41	10.02	8.51	7.18	4.99	3.40
Barn Case 8	100	13.08	11.13	10.23	9.41	7.98	6.75
Marce Case 7	120	14.94	12.79	11.47	10.30	8.34	6.85
	Mean	**2.32**	**-0.52**	**-2.64**	**-4.56**	**-7.27**	**-8.80**
	Std.dev	**7.88**	**7.77**	**8.22**	**8.62**	**9.04**	**9.06**

Unlike the Modified Duong and SEDM, the Modified Arps method (Dmin@5%) provides exceptional results for wells where BDF begins after 50 months. The results in **Table.25c** are testament to the fact that Arps (Dmin@5%) imparts the lowest discrepancy in remaining reserves irrespective of the amount of history matched data. Therefore it can be safely said that if BDF begins or is predicted to begin after 50 months, comparable to a lot of the present Barnett BDF wells, Arps (Dmin@5%) would be the recommended model.

In some of the newer shale plays like the Fayetteville, Haynesville and even some wells in the Barnett it is observed that BDF begins before 50 months so it would be interesting how the Modified Duong, SEDM and Arps (Dmin @5%) perform when BDF begins before 50 months. **Table 26a-c** provides a comparison on the ability of various empirical models to forecast production if BDF begins after 50 months. In **Table.26a** it is evident that the Modified Duong does an acceptable job in forecasting production for wells where BDF occurs before 50 months especially for 6-12 months of matched data, which is highly desirable. The SEDM does not work that well for wells where BDF occurs before 50 months as seen in **Table.26b.** The SEDM does an average job with 36 months of data but since the aim is to find a model that can consistently forecast production with BDF, the SEDM does not fit that criterion and therefore it would not be recommended for any well that includes a BDF flow regime or is forecasted to go into boundary flow.

Table 26a - Discrepancy (% error) in remaining reserves where BDF begins before 50 months for the Modified Duong method (Dswitch @5%)

	Modified Duong (Dswitch@ 5%)- Discrepancy(% error) in remaining reserves						
	BDF start time,months	6 months matched	12 months matched	18 months matched	24 months matched	36 months matched	48 months matched
Marce Case 23	15	-44.86	-28.50	-25.05	-15.07	-18.94	-12.88
Barn Case 2	17	4.01	-19.37	-24.57	-10.29	-12.11	-3.02
Marce Case 1	18	15.94	-9.40	-20.31	-10.26	-18.76	-12.08
Marce Case 8	18	1.27	-20.92	-24.94	-10.18	-11.00	-1.70
Marce Case 18	18	0.17	-20.96	-25.40	-11.43	-12.67	-3.59
Marce Case 3	20	-3.37	-35.42	-49.60	-36.63	-45.73	-34.23
Marce Case 5	20	5.68	-23.13	-35.55	-23.75	-32.16	-22.74
Barn Case 12	20	14.71	-9.24	-19.25	-9.23	-16.61	-9.74
Barn Case 15	20	12.92	-11.78	-20.69	-9.16	-14.69	-6.96
Marce Case 16	25	14.31	-5.79	-16.55	-9.46	-20.11	-15.53
Barn Case 5	25	21.87	-1.97	-14.21	-6.76	-18.56	-13.86
Barn Case 6	25	1.90	-11.43	-18.83	-12.19	-19.77	-15.07
Marce Case 2	30	-19.42	-27.08	-30.06	-21.28	-23.21	-16.35
Barn Case 7	30	-11.22	-21.12	-25.68	-17.58	-21.18	-14.91
Barn Case 16	30	23.68	0.93	-14.00	-9.89	-31.83	-32.20
Marce Case 9	35	-2.25	-10.85	-16.90	-11.82	-20.22	-17.34
Barn Case 21	35	19.03	-1.00	-14.56	-10.62	-31.05	-31.37
Marce Case 17	40	20.59	2.23	-9.05	-4.27	-18.60	-16.78
Marce Case 19	40	24.02	5.68	-5.84	-1.66	-17.38	-16.60
Barn Case 11	40	30.76	10.49	-2.19	1.73	-15.56	-15.48
Barn Case 17	40	31.80	12.17	-1.12	1.96	-21.04	-25.01
Barn Case 25	40	30.08	7.87	-6.42	-2.53	-23.32	-24.09
Barn Case 3	45	-11.81	-1.48	-2.40	2.10	-11.94	-15.54
Barn Case 14	45	34.80	15.05	2.39	5.68	-13.02	-14.38
Barn Case 22	45	33.20	12.71	-1.02	2.12	-21.37	-25.42
	Mean	**9.91**	**-7.69**	**-16.87**	**-9.22**	**-20.43**	**-16.67**
	Std.dev	**19.03**	**14.29**	**12.21**	**9.34**	**7.84**	**8.63**

Table.26b- Discrepancy (% error) in remaining reserves where BDF begins before 50 months for the SEDM

		SEDM- Discrepancy (% error) in remaining reserves					
	BDF start time,months	6 months matched	12 months matched	18 months matched	24 months matched	36 months matched	48 months matched
Marce Case 23	15	14.24	-5.46	-6.61	-1.24	18.80	53.99
Barn Case 2	17	60.59	50.49	34.39	50.96	44.36	24.79
Marce Case 1	18	19.25	4.82	-2.03	-3.42	46.54	43.94
Marce Case 8	18	17.76	-8.02	64.26	2.74	21.95	55.01
Marce Case 18	18	21.76	-7.13	62.53	1.39	19.82	52.45
Marce Case 3	20	4.72	-14.06	58.05	48.43	-12.10	6.87
Marce Case 5	20	10.71	-5.51	-13.21	-13.92	-6.55	43.29
Barn Case 12	20	16.80	2.81	-2.93	-3.36	1.60	13.33
Barn Case 15	20	15.02	2.11	-2.93	-2.54	7.23	18.78
Marce Case 16	25	35.15	0.95	58.84	-7.07	-5.45	35.30
Barn Case 5	25	23.22	10.07	2.10	-1.28	-0.93	2.50
Barn Case 6	25	48.00	1.32	45.18	38.16	-1.75	28.55
Marce Case 2	30	53.04	46.15	28.67	26.89	24.44	15.74
Barn Case 7	30	47.00	42.74	36.10	2.51	5.75	27.52
Barn Case 16	30	27.99	13.73	3.88	-3.59	-10.82	-12.35
Marce Case 9	35	51.81	50.08	38.72	29.20	20.76	18.24
Barn Case 21	35	36.02	7.72	-0.60	-6.73	-12.29	-13.76
Marce Case 17	40	40.91	7.61	2.59	-2.56	34.82	-3.46
Marce Case 19	40	41.93	12.12	5.42	48.63	-3.07	-2.78
Barn Case 11	40	32.54	19.65	11.27	5.91	0.70	0.27
Barn Case 17	40	35.81	23.37	14.42	7.64	0.00	-5.56
Barn Case 25	40	33.20	20.40	11.20	3.64	-3.30	-5.23
Barn Case 3	45	70.94	67.76	35.46	21.34	35.88	-2.76
Barn Case 14	45	35.31	25.00	15.97	9.98	3.68	2.27
Barn Case 22	45	36.67	25.13	15.60	8.49	-0.20	-5.64
	Mean	**33.21**	**15.75**	**20.65**	**10.41**	**9.19**	**15.65**
	Std.dev	**16.41**	**21.38**	**23.78**	**19.06**	**17.55**	**21.83**

Unlike its forecasts in **Table 25c** the Modified Arps method (Dmin @5%) does a poor job in forecasting wells with BDF occurring before 50 months as seen in **Table.26c.**

Table.26c- Discrepancy (% error) in remaining reserves where BDF begins before 50 months for the Arps (Dmin @5%)

		Arps (Dmin @5%)- Discrepancy (% error) in remaining reserves					
	BDF start time,months	6 months matched	12 months matched	18 months matched	24 months matched	36 months matched	48 months matched
Marce Case 23	15	-49.88	-57.42	-51.74	-39.18	-16.58	-1.29
Barn Case 2	17	-51.85	-16.84	-30.82	-23.66	-18.04	-9.49
Marce Case 1	18	-34.03	-41.06	-44.80	-43.09	-28.53	-15.53
Marce Case 8	18	-52.76	-56.57	-51.07	-37.58	-14.21	0.93
Marce Case 18	18	-48.48	-57.01	-50.78	-38.43	-16.24	-1.28
Marce Case 3	20	-60.05	-84.53	-84.98	-77.07	-54.48	-32.30
Marce Case 5	20	-51.55	-64.13	-67.78	-60.65	-41.59	-23.67
Barn Case 12	20	-33.69	-39.17	-42.69	-40.62	-25.68	-12.67
Barn Case 15	20	-38.65	-44.74	-48.09	-40.59	-22.83	-8.65
Marce Case 16	25	-23.07	-29.70	-33.31	-35.46	-29.77	-19.99
Barn Case 5	25	-24.02	-28.80	-32.43	-34.49	-29.00	-18.96
Barn Case 6	25	-19.35	-24.50	-27.96	-30.01	-26.87	-17.63
Marce Case 2	30	-25.87	-31.80	-35.33	-37.05	-25.13	-13.83
Barn Case 7	30	-23.34	-28.93	-32.42	-34.22	-25.14	-14.28
Barn Case 16	30	-20.75	-29.66	-33.57	-36.87	-41.34	-38.68
Marce Case 9	35	-11.25	-15.87	-19.06	-21.34	-23.50	-19.80
Barn Case 21	35	-21.37	-28.83	-32.67	-35.86	-40.24	-37.76
Marce Case 17	40	-12.84	-18.45	-21.73	-24.06	-26.36	-22.13
Marce Case 19	40	-9.36	-14.85	-17.93	-20.26	-22.80	-21.94
Barn Case 11	40	-7.70	-11.09	-14.09	-16.39	-19.00	-19.76
Barn Case 17	40	-8.35	-15.01	-17.72	-20.18	-24.04	-26.52
Barn Case 25	40	-13.75	-19.22	-22.55	-25.27	-28.83	-29.72
Barn Case 3	45	-22.68	-8.55	-7.36	-14.31	-19.40	-20.75
Barn Case 14	45	-2.86	-5.91	-8.63	-10.81	-13.61	-14.79
Barn Case 22	45	-9.69	-15.18	-17.93	-20.40	-24.30	-26.81
	Mean	**-27.09**	**-31.51**	**-33.90**	**-32.71**	**-26.30**	**-18.69**
	Std.dev	**16.98**	**19.82**	**18.38**	**14.48**	**9.56**	**10.28**

Therefore after analyzing **Table 25a-c** and **Table 26a-c** it can be safely put forward that if a well is projected to go into BDF before 50 months the Modified Duong method (Dswitch @5%) is recommended, but if a well is projected to go into BDF after 50 months, the Modified Arps model (Dmin @5%) model is recommended. The SEDM is not recommended for models that exhibit or likely to exhibit BDF.

CHAPTER V

COMPARISON OF VARIOUS EMPRICAL DECLINE MODELS FOR GROUPED DATASETS

Up to now all analysis performed was on individual wells and in shale gas reservoirs it is highly desirable that grouped datasets also be looked at due to the sizeable amount of wells. **Fig. 36**, **Fig. 37** and **Fig. 38** are a representation of how different decline models behave for grouped data sets.

Fig.36 shows a 130 grouped well set in the Johnson county (Barnett shale) with empirical model comparisons and **Table 27** displays the results of various empirical models for 18 months of matched history. It is evident that the Modified Arps (Dmin@5%) model, overestimates the true production while the SEPD and Duong provide reasonable forecasts. In this case the original Duong with $q_{\infty}=0$ provides the lowest discrepancy in remaining reserves. The Modified Duong method too performs exceptionally well for grouped datasets. The Duong method was also used with a value for q_{∞} but in **Fig. 37** it is shown that using a q_{∞} provides unreliable results similar to the results for individual wells. EOH & EOP refer to the end of history & production respectively.

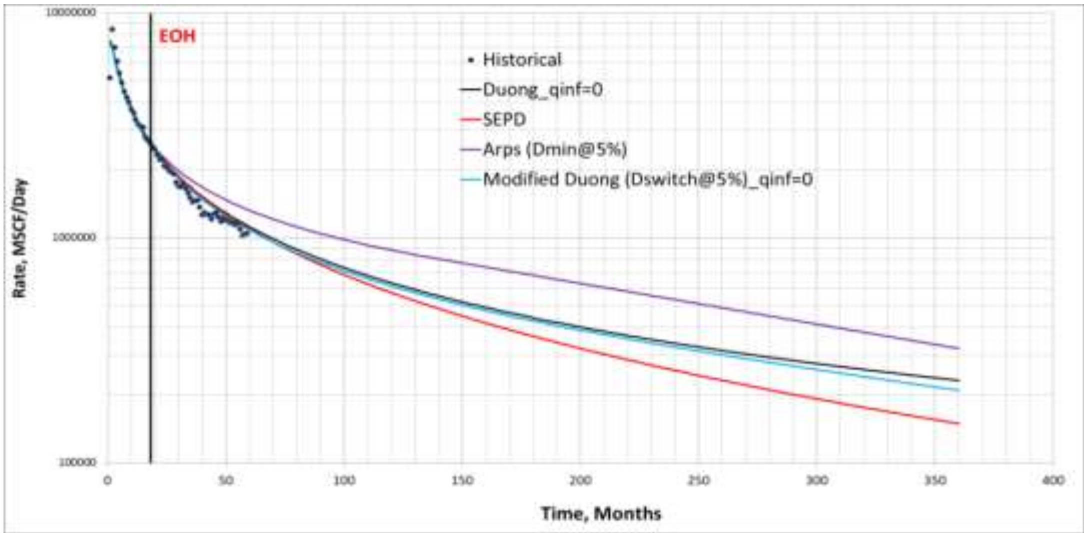

Figure 36- Comparison of empirical models for a 130 well Johnson county group using 18 months of matched data

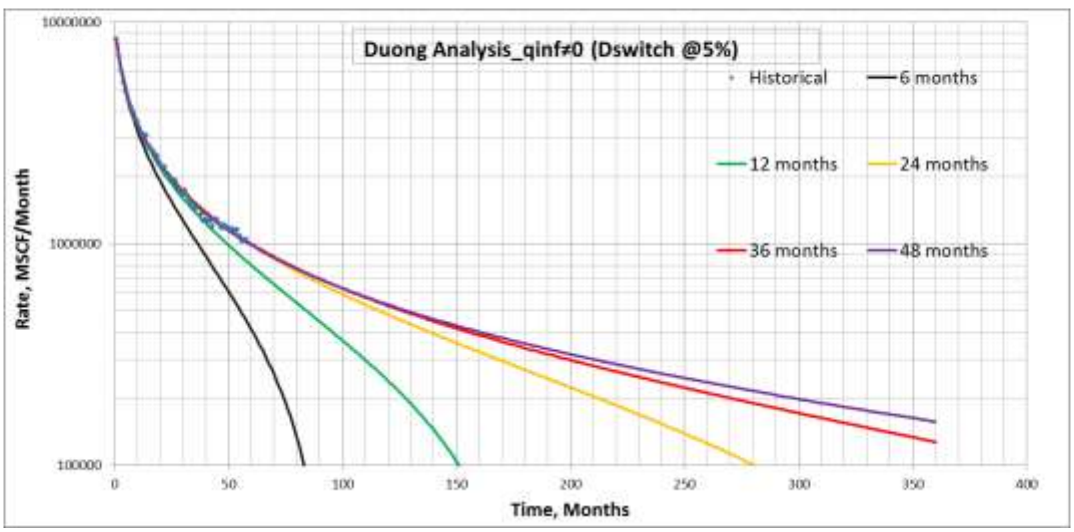

Figure 37- Comparison of the Duong method with q_∞ for a 130 well Johnson county group using varying months of matched data

Table 27- Discrepancy (% error) in remaining reserves for a 130 well Johnson county group

Method	Reserves (After EOP)(BSCF)	Reserves (After EOP) BSCF/Well	%Discrepancy
Arps (Dmin@5%)	197.168	1.517	-17.7
Modified Duong (Dswitch@5%)_qinf=0	132.856	1.022	-4.8
SEPD	116.648	0.897	-7.2
Duong_qinf=0	138.214	1.063	-8.3

Fig.38 shows an 81 grouped well set in the Denton county (Barnett shale) with different empirical model comparisons and **Table 28** displays the results of various empirical models for 36 months of matched history. It is evident that the Arps (Dmin@5%) model, similar to the Johnson well set, overestimates the true production while the SEPD and Duong method provide reasonable forecasts. The Modified Duong method provides the lowest discrepancy in remaining reserves in the case of **Fig.38**. The original Duong method with q_∞=0 too performs exceptionally well for grouped datasets. **Fig.39** shows a 127 grouped well set in the Wise county (Barnett shale) with empirical model comparisons and **Table 29** displays the results of various empirical models for 36 months of matched history.

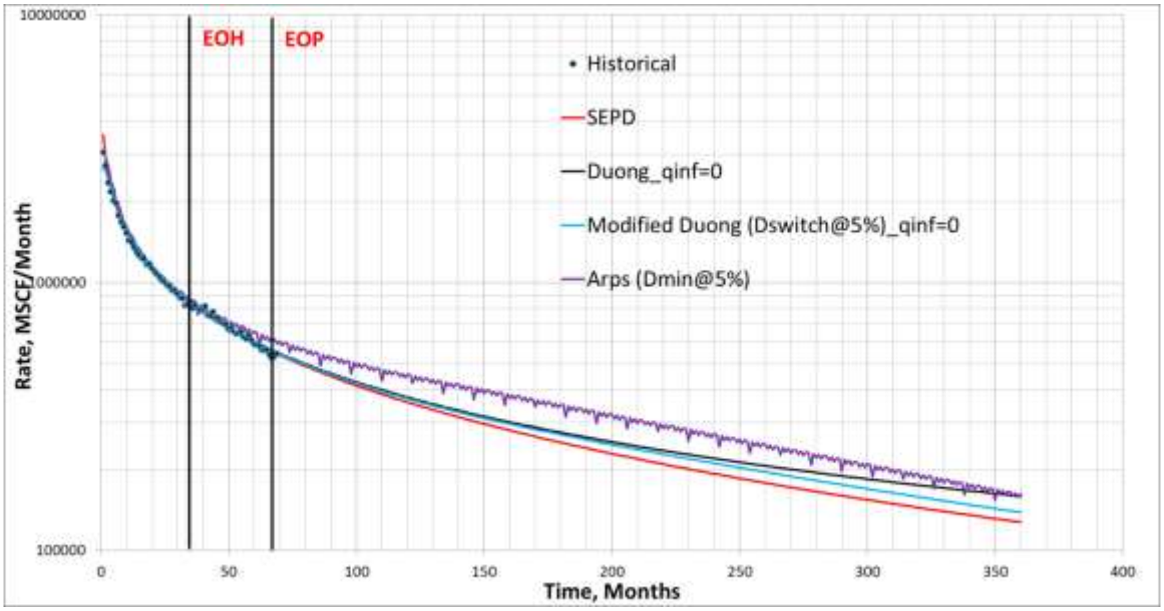

Figure 38- Comparison of empirical models for an 81 well Denton county group using 36 months of matched data

Table 28- Discrepancy (% error) in remaining reserves for an 81 well Denton county group

Method	Reserves (After EOP)(BSCF)	Reserves (After EOP) BSCF/Well	%Discrepancy
Terminal Decline @5%	91.571	1.131	-4.2
Modified Duong (Dswitch@5%)_qinf=0	75.244	0.929	1.5
SEPD	71.074	0.877	2.2
Duong_qinf=0	77.921	0.962	1.0

It is evident that the Modified Arps method (Dmin@5%) model, like for the Denton well set, overestimates the true production while the SEPD and Duong provide reasonable forecasts. In this case the original Duong method provides the lowest discrepancy in remaining reserves. The Modified Duong method too performs exceptionally well for grouped datasets.

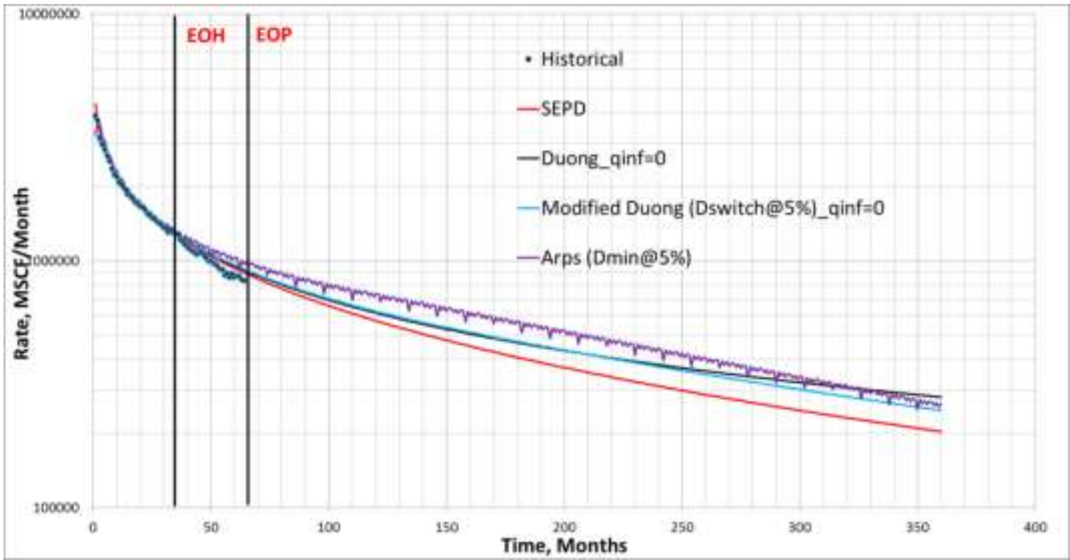

Figure 39- Comparison of empirical models for a 127 well Wise county group using 36 months of matched data

Table 29- Discrepancy (% error) in remaining reserves for a 127 well Wise county group

Method	Reserves (After EOP)(BSCF)	Reserves (After EOP) BSCF/Well	%Discrepancy
Terminal Decline @5%	153.925	1.212	-10.4
Modified Duong (Dswitch@5%)_qinf=0	135.140	1.064	-7.0
SEPD	118.967	0.937	-4.3
Duong_qinf=0	136.625	1.076	-6.1

Fig.40 shows a 107 grouped well set in the Van Buren county (Fayetteville shale) with empirical model comparisons and **Table 30** displays the results of various empirical models for 18 months of matched history. For this groupset unlike the previous three well sets the Modified Arps method (Dmin@5%) model underestimates the true production while the SEPD and Duong provide reasonable forecasts. In this case the SEPD provides the lowest discrepancy in remaining reserves. The Modified Duong

too performs exceptionally well for grouped datasets. The difference between the Van Buren group set and the previous 3 Barnett sets is the variability in 30 YR EUR as seen in **Table 30**.

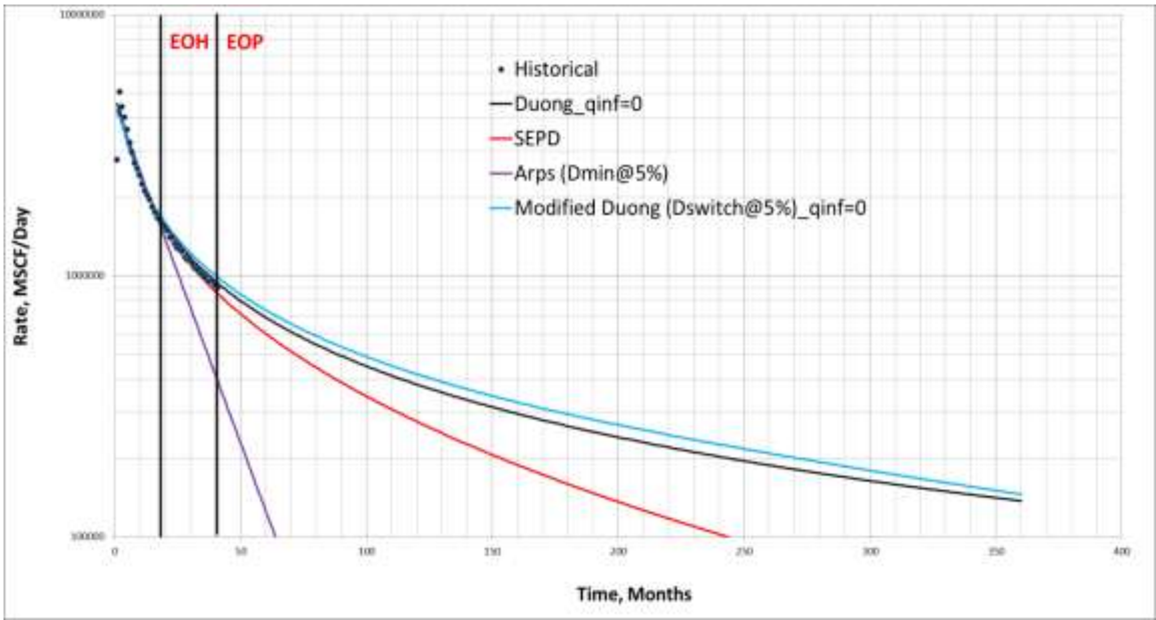

Figure 40- Comparison of empirical models for a 107 well VanBuren county group using 18 months of matched data

Table 30- Discrepancy (% error) in remaining reserves for a 107 well Van Buren county group

Method	Reserves (After EOP)(BSCF)	Reserves (After EOP) BSCF/Well	%Discrepancy
Arps (Dmin@5%)	6.346	0.059	32.5
Modified Duong (Dswitch@5%)_qinf=0	106.799	0.998	-8.0
SEPD	66.419	0.621	3.1
Duong_qinf=0	98.030	0.916	-4.0

CHAPTER VI

CONCLUSIONS

- Based on the available field data the optimal way to forecast production data using the Duong method, in regard to q_∞, would be to force q_∞ to be zero for limited data (6-24 months) months.

- Based on simulated data the optimal way to forecast production data using the Duong method, in regard to q_∞, would be to force q_∞ to be equal to zero for all history matched months.

- To account for late term BDF the Modified Duong method (D_{switch} @5%) with q_∞=0 and proves to be the optimal Duong technique amongst the different Duong models looked at.

- For 6 months of data the Modified Duong method (D_{switch} @5%) with q_∞=0 does not forecast accurately. But for 12 months or more of history matched data the Modified Duong method provides acceptable forecasts for all counties except the Tarrant county for which there was an operational change after 35 months.

- For actual wells with observed BDF, the Modified Duong with q_∞=0 performs poorly for short term data and using a q_∞ works better.

- Based on the statistics and production plots we conclude that even though q_∞ provides us with better statistics for actual wells more conducive validation requires comparison of the forecast with longer observed well histories.

- For the simulated case the Modified Duong method (D_{switch} @5%) with $q_\infty=0$ works better than the Modified Duong (D_{switch} @5%) with $q_\infty\neq0$.

- For actual data the Modified Duong method (D_{switch} @5%) with $q_\infty=0$ is the best model compared to the Arps (D_{min} 5%) and SEDM for all periods of history matched data except for 6 months where the Modified Arps method (D_{min} 5%) has better statistics.

- For actual data the Modified Arps method with a D_{min} of 5% is the best model to match and forecast wells with BDF observed in evaluable historical production data especially for 6-12 months of production data.

- For simulated data none on the models work accurately for shorter matched histories, even though the Modified Arps method performs the best with the lowest mean and standard deviation in the discrepancy/error of remaining reserves.

- For simulated data the Modified Duong method (Dswitch @5%) with $q_\infty=0$ turns out to be the best model for 12-48 months of matched history.

- Based on simulations the Modified Duong does exceptionally well in forecasting production for wells where BDF is excluded in the match.

- The SEDM does a poor job in forecasting production for wells where BDF appears but not included in the determining match.

- The Modified Arps method (D_{min} @5%) also produces average results in forecasting production where BDF occurs beyond the history match.

- Based on simulations if a well is projected to go into BDF before 50 months the Modified Duong method (D_{switch} @5%) is recommended, but if a well is projected to go into BDF after 50 months, the Arps (D_{mi}n @5%) model is produces more accurate results.

- The Duong method provides extremely accurate results for 18-24 months of matched data irrespective of the flow regime occurring within the match or after the match.

- The SEDM is not recommended for models that exhibit or are expected to exhibit BDF.

- Based on simulations, even though the Modified Duong method (D_{switch} @5%) provides statistically better results, none of the models can accurately forecast production when BDF is included in the history match.

- For grouped well sets the SEPD and Modified Duong method (D_{switch} @5%) work exceptionally well providing reasonable forecasts.

- For grouped well sets the Modified Arps method (D_{min}@5%) is not recommended.

- The above results are only applicable to the Barnett & Fayetteville shale. Therefore the Dswitch and b values may vary for different shales.

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NOMENCLATURE

qi = Initial rate, MSCF/Day

b = Hyperbolic exponent, dimensionless

Di = Initial decline rate. Time^-1

D_{term} = Minimum decline rate, time^-1

Q = Flow rate, MSCF/Day

τ = Median of the characteristic time constants

n = Exponent parameter

qo = Initial production rate, MSCF/Day

a = Intercept of q vs. Gp plot, time^-1

m = Slope of q vs. Gp plot

Gp= Cumulative Production, MSCF

q_∞ or qinf = Rate at infinite time, MSCF/Day

ACRONYMS

SRV- Stimulated reservoir volume

BDF-Boundary dominated flow

GCi – Initial gas content

Xw- Well spacing

Xe- Reservoir length

Ye- Reservoir breadth