APPLICATION OF THE STRETCHED EXPONENTIAL PRODUCTION DECLINE MODEL TO FORECAST PRODUCTION IN SHALE GAS RESERVOIRS

A Thesis

by

JAMES CODY STATTON

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

May 2012

Major Subject: Petroleum Engineering

Application of the Stretched Exponential Production Decline Model to Forecast

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Approved by:

Chair of Committee,	John Lee
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ABSTRACT

Application of the Stretched Exponential Production Decline Model to Forecast Production in Shale Gas Reservoirs. (May 2012)

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Production forecasting in shale (ultra-low permeability) gas reservoirs is of great interest due to the advent of multi-stage fracturing and horizontal drilling. The well renowned production forecasting model, Arps' Hyperbolic Decline Model, is widely used in industry to forecast shale gas wells. Left unconstrained, the model often overestimates reserves by a great deal. A minimum decline rate is imposed to prevent overestimation of reserves but with less than ten years of production history available to analyze, an accurate minimum decline rate is currently unknown; an educated guess of 5% minimum decline is often imposed. Other decline curve models have been proposed with the theoretical advantage of being able to match linear flow followed by a transition to boundary dominated flow. This thesis investigates the applicability of the Stretched Exponential Production Decline Model (SEPD) and compares it to the industry standard, Arps' with a minimum decline rate. When possible, we investigate an SEPD type curve.

Simulated data is analyzed to show advantages of the SEPD model and provide a comparison to Arps' model with an imposed minimum decline rate of 5% where the full production history is known. Long-term production behavior is provided by an analytical solution for a homogenous reservoir with homogenous hydraulic fractures. Various simulations from short-term linear flow (~1 year) to long-term linear flow (~20 years) show the ability of the models to handle onset of boundary dominated flow at various times during production history. SEPD provides more accurate reserves estimates when linear flow ends at 5 years or earlier. Both models provide sufficient reserves estimates for longer-term linear flow scenarios.

Barnett Shale production data demonstrates the ability of the models to forecast field data. Denton and Tarrant County wells are analyzed as groups and individually. SEPD type curves generated with 2004 well groups provide forecasts for wells drilled in subsequent years. This study suggests a type curve is most useful when 24 months or less is available to forecast. The SEPD model generally provides more conservative forecasts and EUR estimates than Arps' model with a minimum decline rate of 5%.

DEDICATION

This work is dedicated to my wife, family and friends. Jacci has been supportive, loving, and patient throughout this process. My parents and grandparents have always been overly supportive and proud of my academic endeavors - I am blessed and grateful. Uncle Eddy has been a great supporter and mentor to me throughout my college years –I owe him many thanks and fishing trips.

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The patience and guidance of Dr. John Lee is greatly appreciated. Dr. McVay and Dr. Blasingame also provided valuable assistance for which I am thankful. Dr. Maria Barrufet and Dr. Schechter both gave me their time and helped my research.

Free use of DrillingInfo.com© and Fekete© made the objectives of my thesis possible. I owe big thanks to these guys for sponsoring our academic endeavors and allowing students use of their software free of charge. I also owe Hampton Roach at Shell Oil Company a thank you for providing us with his software – it provided a valuable quality check against our own SEPD software package.

TABLE OF CONTENTS

Page

LIST OF TABLES

TABLE Page

TABLE Page

TABLE Page

LIST OF FIGURES

Page

Page

Page

Page

Page

Page

Page

Page

I. INTRODUCTION

1.1 Importance of Research

The majority of shale gas reservoirs and ultra-tight source rocks have long been considered non-commercial hydrocarbon deposits. Advances in horizontal drilling and multi-stage fracturing treatments combined with favorable commodity prices have revolutionized natural gas and petroleum liquids production from ultra-low permeability rocks over the last decade. One of the most notable shale gas reservoirs, the Barnett Shale, began its take off during the early 2000's in and around Fort Worth, TX.

With only a basic understanding of post completion fracture geometries (natural and hydraulic), it is difficult for reservoir engineers to effectively model Barnett Shale production. Further, reservoir modeling is not always a feasible method to forecast hundreds or thousands of wells because of time and resource constraints. For this reason, most if not all companies use decline curve analysis to predict future production from oil & gas wells. This practice has been accepted in industry for many years in conventional and unconventional reservoirs alike. With less than 10 years of data available for horizontal wells with multi-stage fracture completions, many questions and uncertainties remain concerning the long-term behavior of shale gas reservoirs like the Barnett Shale. The question of how well decline curves will predict future volumes in shale gas wells is one of great concern.

This thesis follows the style and format of SPE Journal.

Predicting the volume of hydrocarbons that can be produced economically (reserves) is of the utmost importance to engineers, investors, and government organizations. Since we do not have long-term production data available from shale gas wells with multi-stage fractures, the best we can do is investigate our models for various possibilities that may occur – whether good or bad. Determining the level of accuracy our models provide and quantifying the changes in reserves estimates as more production history becomes available are steps we must take to answer the big questions. This work puts two of the most popular models to the test with simulated data and actual production data of Barnett Shale gas wells.

1.2 **Status of the Question**

The most widely used decline curve model was developed by J. J. Arps (Arps, 1945). As noted by Lee and Sidle (Lee and Sidle, 2010), Arps' decline curve model is totally empirical and consists of three forms: exponential, hyperbolic, and harmonic (Lee and Sidle, 2010). All three forms are based on Eq. 1 where the specific form is defined by the value of the "b factor" as follows: b=0 for exponential; b=1 for harmonic; 0<b<1 and b>1 for hyperbolic.

$$q = q_i \frac{1}{(1+bD_i t)^{\left(\frac{1}{b}\right)}} \quad \text{..........} (1)$$

Where q is production rate at time t (volume over time), b is Arps' hyperbolic decline constant (dimensionless), q_i is initial rate (volume/time), and D_i is Arps' initial decline constant (dimensionless).

Fetkovich et al. provided proof that Arps' exponential model can be derived for producing reservoirs (Fetkovich et al., 1996) that honor the following assumptions:

1) Boundary-dominated flow (depletion period)
2) Constant bottomhole pressure
3) Low or slightly compressible fluids
4) Fixed skin factor

Inherent in these assumptions is the fact the "b factor" remains constant. Several authors have shown the "b factor" to be unstable and usually decreasing with time when forecasting tight gas simulated data sets and field cases (Kupchenko et al., 2008; Rushing et al., 2007). The reason for the instability is attributed to long periods of transient flow prior to a transition to boundary dominated flow – a condition that is often seen in wells producing from tight reservoirs with hydraulic fracture stimulations. During transient flow, the "b factor" that best fits production data in tight gas wells is often greater than 1. When the "b factor" is greater than 1, an unconstrained Arps' model has been shown to yield high to excessively high reserves estimates. (Ilk et al., 2008; Lee and Sidle, 2010).

Industry personnel often apply one of two common constraints to Arps' hyperbolic model to put a cap on reserves estimates. Those methods are the minimum decline rate method (Harrell et al., 2004) and the terminal decline method. The minimum decline rate method combines an Arps' hyperbolic fit with an imposed minimum decline rate (D_{min}) in order to prevent excessively high reserves estimates. The terminal decline method begins with an Arps' hyperbolic fit (often with a "b factor" greater than 1) followed by exponential decline that is forced at a specified date or production rate.

With the explosion of shale gas activity during the last decade, new methods have been proposed to model the behavior exhibited by long horizontal wells with multi-stage hydraulic fractures in shale reservoirs. These methods include but are not limited to the Stretched Exponential Production Decline (SEPD) model (Valko and Lee, 2010), the Power Law model (Ilk et al., 2008), and Duong's model (Duong, 2010).

The Power Law model and SEPD are based off of the stretched exponential function first introduced by Kohlrausch in 1854 to describe the discharge of capacitors (Ilk et al., 2010). The authors note that while these models are empirical, there are multiple references in physics' literature providing evidence of the stretched exponential function's ability to model decays – particularly decays in randomly disordered and chaotic systems. The Power-Law (Eq. 2) and SEPD (Eq.3) rate-time equations are defined as follows:

$$q(t) = \widehat{q}_i \exp[-\widehat{D}_i t^n] \quad (2)$$

$$q(t) = \hat{q}_i \exp[-\left(\frac{t}{\tau}\right)^n] \quad (3)$$

Where q(t) is production rate (volume/day), $\widehat{D}_i$ is the rate-time equation parameter, D^{-1}, t is production time, n is the time exponent (dimensionless), and τ is the characteristic time constant (time). Ilk et al. (2008) provide several theoretical advantages of the stretched exponential models (Power Law and SEPD) over Arps' model, namely the ability of the stretched exponential models to transition from non-exponential decline early on to exponential decline later in the life of a well; they provide evidence with diagnostic plots, simulations and field data using the Power Law.

In 2010, Duong of Conoco Phillips released a model based on the assumption of linear flow. He suggests the connected fracture density of the fractured area has to be increasing over time to support fracture flow over the life of a producing well (Duong, 2010). The following equations (Eq. 4 and Eq. 5) govern Duong's model:

$$t_m = \frac{t}{t_{max}} \qquad (4)$$

$$q = q_{max} t_m^{-m} e^{\frac{m}{1-m}\left(t_m^{1-m}-1\right)} \qquad (5)$$

Where t is time, t_{max} is time at maximum flow rate, q is flowrate (volume/time), m is slope of the straight line through the data on a log-log q/G_p vs. time plot, and q_{max} is the maximum rate (volume/time). Duong's model is shown to perform quite well in situations where long-term linear flow is exhibited. Little evidence exists to show Duong's model will handle a transition to boundary dominated flow halfway through the life of a well. Further studies need to be performed to answer this question.

1.3 Research Objectives

The objectives of this work are to:

- Determine practical limits for the variable τ used in the SEPD model
- Develop a spreadsheet to rapidly forecast public data using the SEPD model
- Evaluate suitability of the following models for shale gas forecasting:

    - Arps' model with a minimum terminal decline - most common method used in industry
    - SEPD model – promising new method designed to handle transient and boundary dominated flow
- Evaluate uncertainty in models
    - Simulated cases
    - Field cases
    - Examine changes in forecasts and EUR estimates as more historical production data becomes available (6 months, 12 months, 24 months, etc.)
    - Examine influence of boundary dominated flow on forecasts
- Determine if and when a type curve is useful

II. STRETCHED EXPONENTIAL PRODUCTION DECLINE MODEL

2.1 SEPD Introduction

As noted previously, the stretched exponential model is the basis for the Power Law and SEPD models that were recently proposed in the Petroleum Engineering world to forecasts tight gas and shale gas reservoirs. Our study focuses on the SEPD model proposed by Valko and Lee in 2010 (Valko and Lee, 2010). The following equations (Eq. 6, Eq. 7 and Eq. 8) govern the SEPD model:

$$\frac{dq}{dt} = -n\left(\frac{t}{\tau}\right)^n \frac{q}{t} \quad (6)$$

$$q = q_0 exp\left[-\left(\frac{t}{\tau}\right)^n\right] \quad (7)$$

$$Q_t = \frac{q_0\tau}{n}\left\{\boldsymbol{\Gamma}\left[\frac{\mathbf{1}}{\boldsymbol{n}}\right] - \boldsymbol{\Gamma}\left[\frac{\mathbf{1}}{\boldsymbol{n}}, \left(\frac{\boldsymbol{t}}{\boldsymbol{\tau}}\right)^{\boldsymbol{n}}\right]\right\} \quad (8)$$

Where Eq. 6 is the defining differential equation of the model, Eq. 7 is the rate expression as a function of time and Eq. 8 is the cumulative production as a function of time. The parameters with units used in this work are as follows:

n: exponent parameter in SEPD model – similar to “b factor” in Arps’ model, dimensionless
τ: characteristic time parameter for SEPD model, month
q: gas flow rate, mcf/month
q_0: initial gas rate*, mcf/month
t: production time, months
Q_t: cumulative gas production up to a specified time, t, mcf
*Initial gas rate is forced to maintain material balance; it will be different than the highest observed volume

As noted by Valko and Lee, rate decline ratios (i.e. $Q_{2\ years}$ over $Q_{1\ year}$) provide a stable method to solve for SEPD parameters (as opposed to minimizing the error between observed data points and solved data points). Using cumulative ratios provides a more transparent method to solve for SEPD model parameters and helps prevent a few anomalous points from having undue influence. Hence in this work we use cumulative production ratios to solve for SEPD parameters. We solve the following two nonlinear equations (Eq. 9 and Eq. 10) for n and τ (by eliminating the q_0 parameter, we solve two equations for two unknowns).

$$\frac{Q_2}{Q_1} = r_{21} = \frac{\Gamma\left[\frac{1}{n}\right]-\Gamma\left[\frac{1}{n},\left(\frac{t_2}{\tau}\right)^n\right]}{\Gamma\left[\frac{1}{n}\right]-\Gamma\left[\frac{1}{n},\left(\frac{t_1}{\tau}\right)^n\right]} \quad (9)$$

$$\frac{Q_3}{Q_1} = r_{31} = \frac{\Gamma\left[\frac{1}{n}\right]-\Gamma\left[\frac{1}{n},\left(\frac{t_3}{\tau}\right)^n\right]}{\Gamma\left[\frac{1}{n}\right]-\Gamma\left[\frac{1}{n},\left(\frac{t_1}{\tau}\right)^n\right]} \quad (10)$$

Rather than using Excel's solver or other software to solve for model parameters, we perform trial and error with various values of n and τ and find the minimum error from the following equation (Eq. 11):

$$\left(r_{21,actual} - r_{21,observed}\right)^2 + \left(r_{31,actual} - r_{31,observed}\right)^2 \quad (11)$$

Finally, we solve for q_0. Observe that q_0 is an instantaneous rate solved to preserve material balance. For a given n and τ, q_0 may be much larger (or smaller) than the highest observed data point. When solving for q_0, we provide a cumulative volume and the time at which the cumulative volume is observed; in this way, the solved cumulative volume is forced to be equal to the observed cumulative volume at the specified time. We rearrange Eq. 12 to solve for q_0 as follows:

$$q_0 = \frac{Q_t\, n}{\tau} / \left\{\Gamma\left[\frac{1}{n}\right] - \Gamma\left[\frac{1}{n}, \left(\frac{t}{\tau}\right)^n\right]\right\} \quad (12)$$

2.2 Parameter Ranges

For all practical purposes, the variable n ranges from 0.1 to 1.0. An n value of 1.0 corresponds to exponential decline while an n value of 0.1 corresponds to a very flat decline. **Fig. 1** gives a visual interpretation of what varying the parameter n does when τ is held constant.

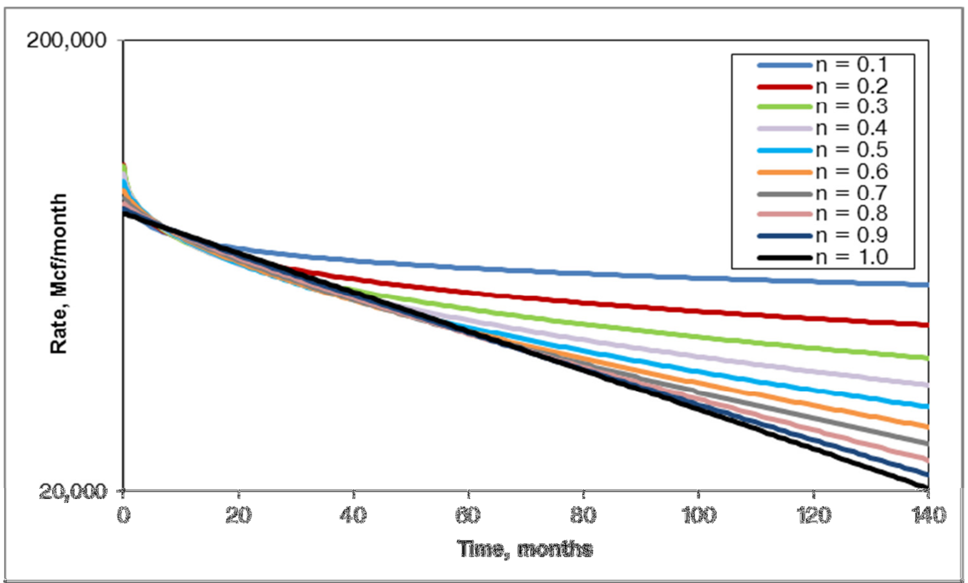

Fig. 1 – A lower n value results in a flatter decline as seen in long-term linear flow situations; an n value of 1.0 gives an exponential forecast.

The practical range for the parameter τ has not been well established. While Valko and Lee never used values greater than 1.0 in their work with Barnett Shale wells, there is no evidence to suggest it should be constrained to 1.0. To determine the practical limits, we apply the model to five simulated cases varying from long-term linear flow (>20 years) to short-term linear flow (~1 year). For each case, we match the entire simulated history and determine the τ values that correspond to the best match. Three field cases (two Barnett and one Fayetteville) are also analyzed using 36 months of data to match production decline. We vary τ from 0.01 to 100 by 0.001 and vary n from 0.01 to 1 by 0.01.

The following figures provide examples of several different scenarios including simulations with known production decline out to 30 years, and shale gas well groups with 4-6 years of production to match. For all cases, a τ range of 0.01 to 100 gives sufficiently small errors (on order of 10^{-18}). We note several of the simulations need τ values greater than 10 to match 360 months of production data (**Fig. 2, Fig. 3, Fig. 4**, and **Fig. 5**). The long-term linear flow simulation (**Fig. 6**) and the field cases (**Fig. 7**, **Fig. 8**, and **Fig. 9**) have minimum errors when τ is less than 10. From this analysis, we conclude ranging τ from 0.01 to 100 and n from 0.1 to 1 provides acceptable errors between predicted and actual volumes. We use these parameter ranges when matching production with the SEPD model for the remainder of the study.

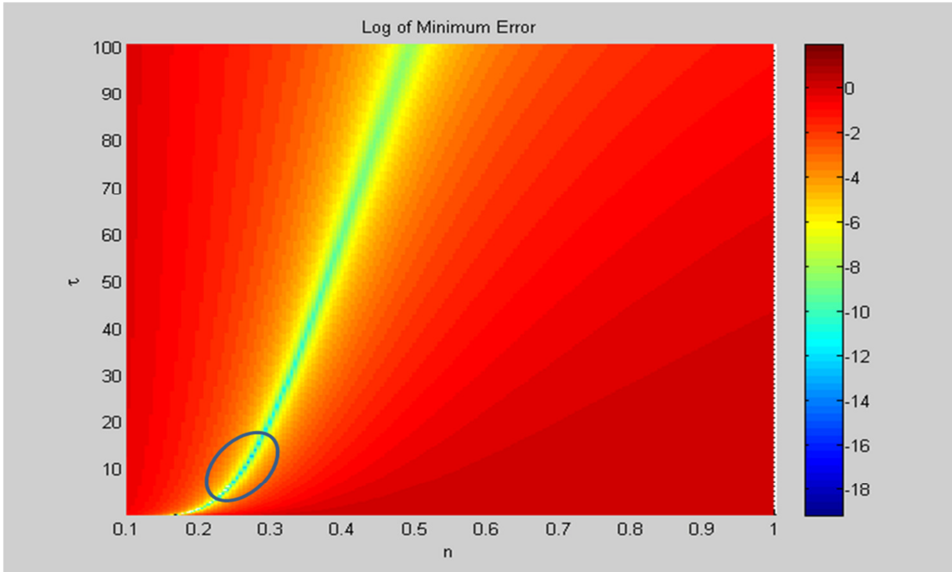

Fig. 2 – Circled are the minimum errors for a case with long-term linear flow; τ values associated with the minimum are around 8.

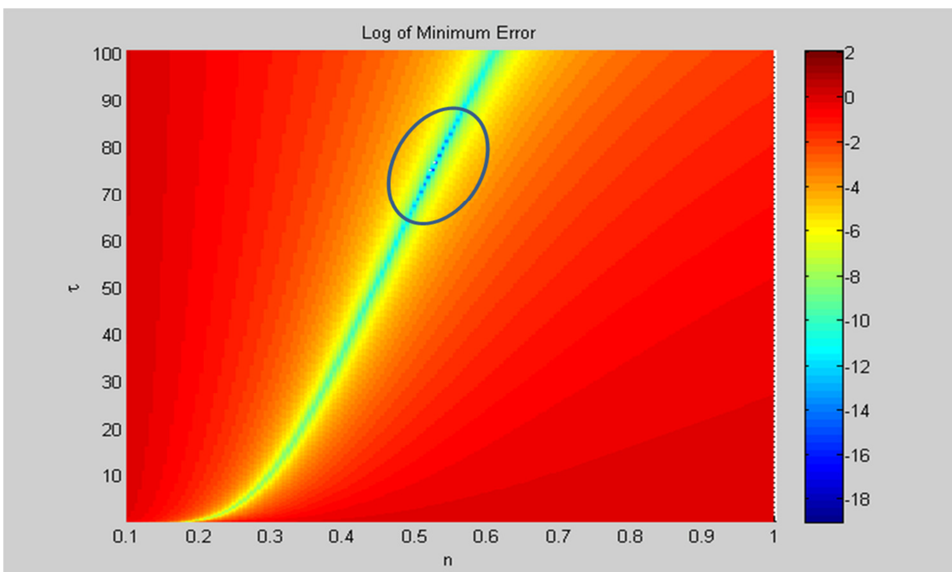

Fig. 3 – Circled are the minimum errors for a case with linear flow transitioning to boundary dominated flow around 16 years; τ values associated with the minimum are in the 70s.

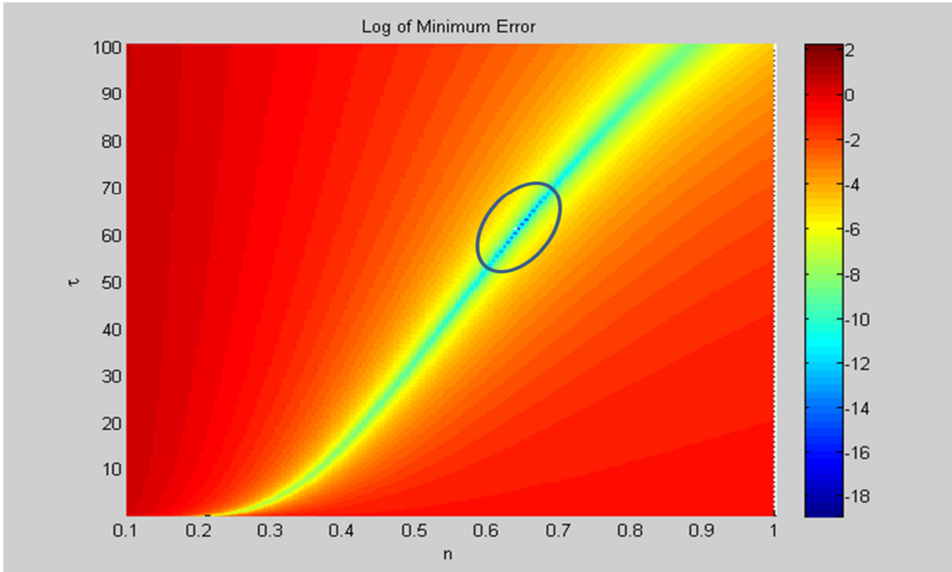

Fig. 4 – Circled are the minimum errors for a case with linear flow transitioning to boundary dominated flow around 7 years; τ values associated with the minimum are in the 60s.

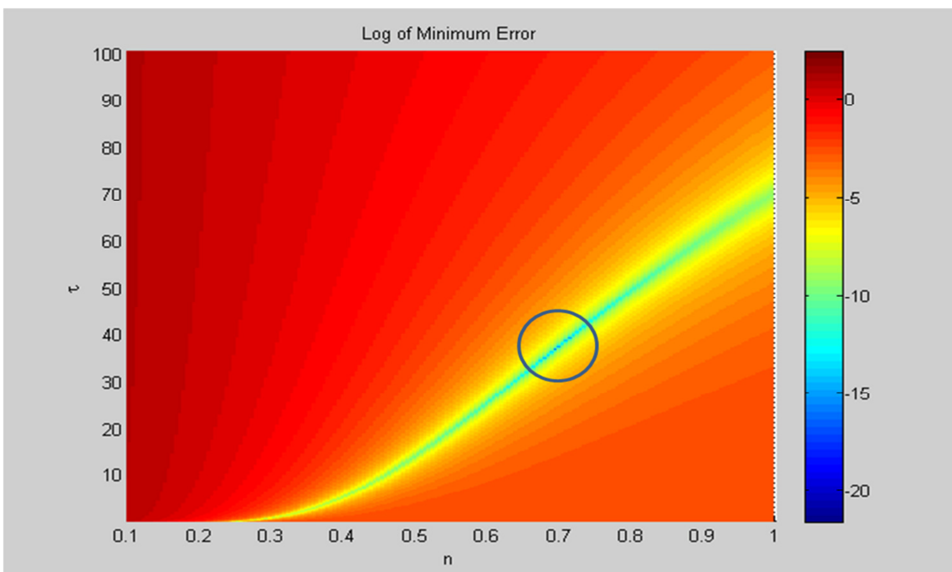

Fig. 5 – Circled are the minimum errors for a case with linear flow transitioning to boundary dominated flow around 3 years; τ values associated with the minimum are in the 40s.

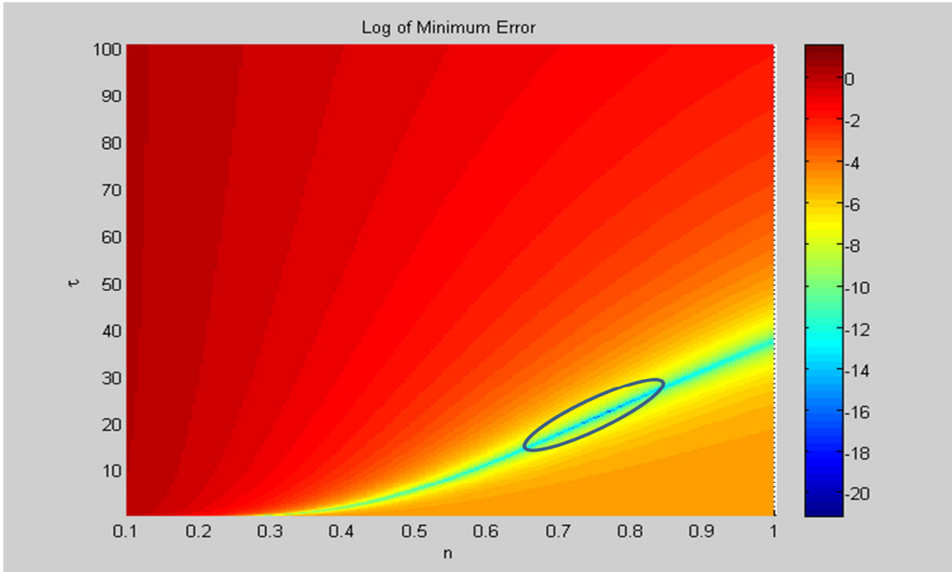

Fig. 6 – Circled are the minimum errors for a case with linear flow transitioning to boundary dominated flow around 1 year; τ values associated with the minimum are in the 20s.

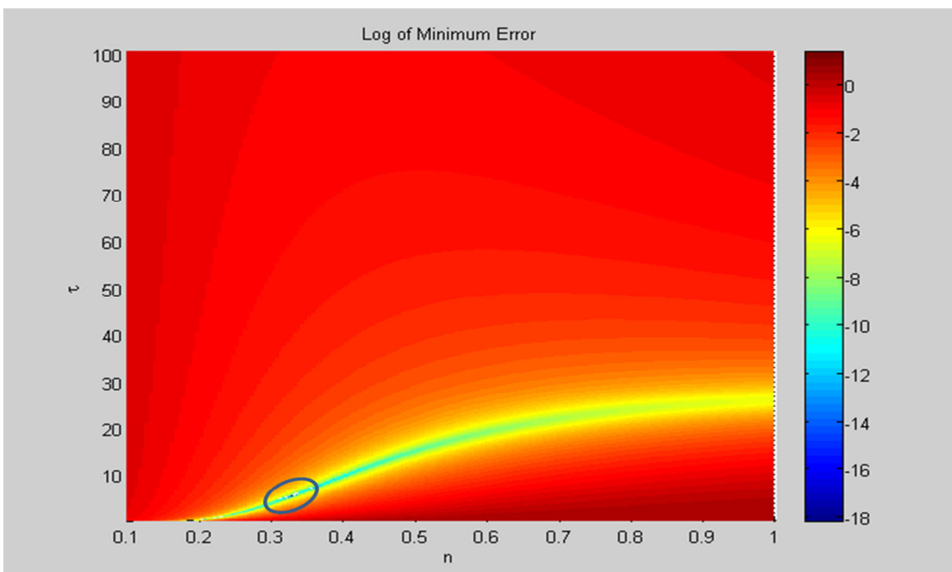

Fig. 7 – Circled are the minimum errors for a group of 2004 Denton County wells (Barnett Shale); τ values associated with the minimum are around 5.

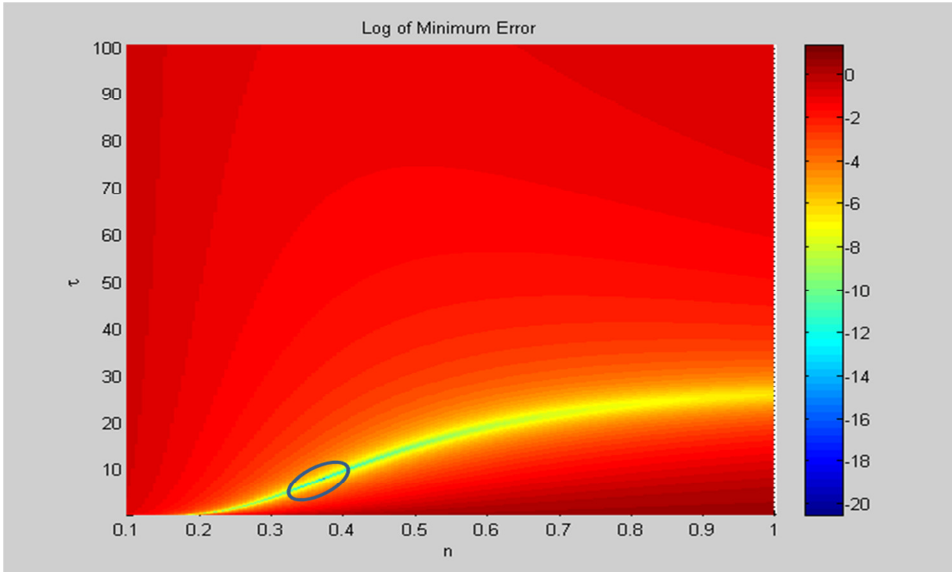

Fig. 8 – Circled are the minimum errors for a group of 2004 Tarrant County (Barnett Shale) wells; τ values associated with the minimum are around 7.

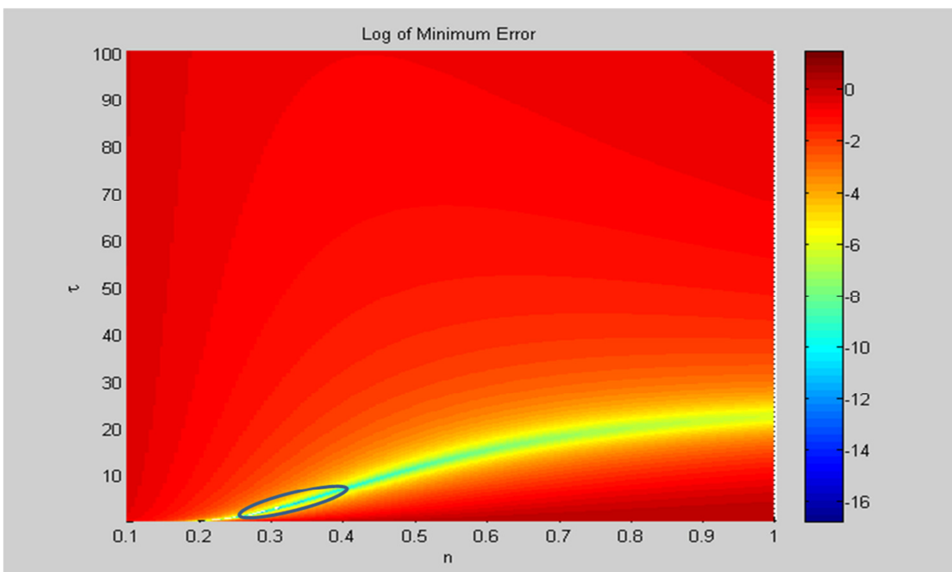

Fig. 9 – Circled are the minimum errors for a group of 2007 Conway County wells (Fayetteville shale); τ values associated with the minimum are around 2.

III. SHALE GAS SIMULATIONS

3.1 **Barnett Shale Simulated: Parameter Set 1**

The Barnett Shale located in and around Fort Worth, Texas has been producing from vertical wells with hydraulic fractures for over 25 years. Starting in 2004, the well design transitioned to primarily horizontal wells with multi-stage fracture stimulations. The majority consensus in literature is hydraulic fractures intersect natural fractures and form complex fracture network systems.

Before developing our simulated cases, we look to the field data to see what types of decline behavior we should anticipate. The data used here and in the remainder of this study is monthly data provided by Drillinginfo.com ©. To reduce noise seen in individual wells, first we analyze groups of wells. The production for all individual wells drilled in a given year is normalized to a common start date and summed. Investigating the log-log plot of rate vs. time for several Barnett Shale yearly well groups and individual wells with smooth production decline profiles provides us with a few estimates of how long linear flow could last. Linear flow is identified by a -1/2 slope on the log-log plot. **Fig. 10** shows a group of 48 wells drilled in Denton County during 2004. An evident departure from linear flow is seen around 3 years. A Denton County 2005 well group (74 wells) does not display evidence supporting a transition from linear flow (**Fig. 11**). It appears linear flow may end around 2 years, but linear flow could be argued again after the departure; the last trend starting around 3.2 years is difficult to diagnose. A clear transition from linear flow for the 2006 Denton County well group is not easily identified (**Fig. 12**). The transition may occur around 2 years but the evidence is not conclusive. Linear flow looks to last the full history for the Denton County 2007 well group (**Fig. 13**). The last few points suggest a transition but more points need to be observed for verification.

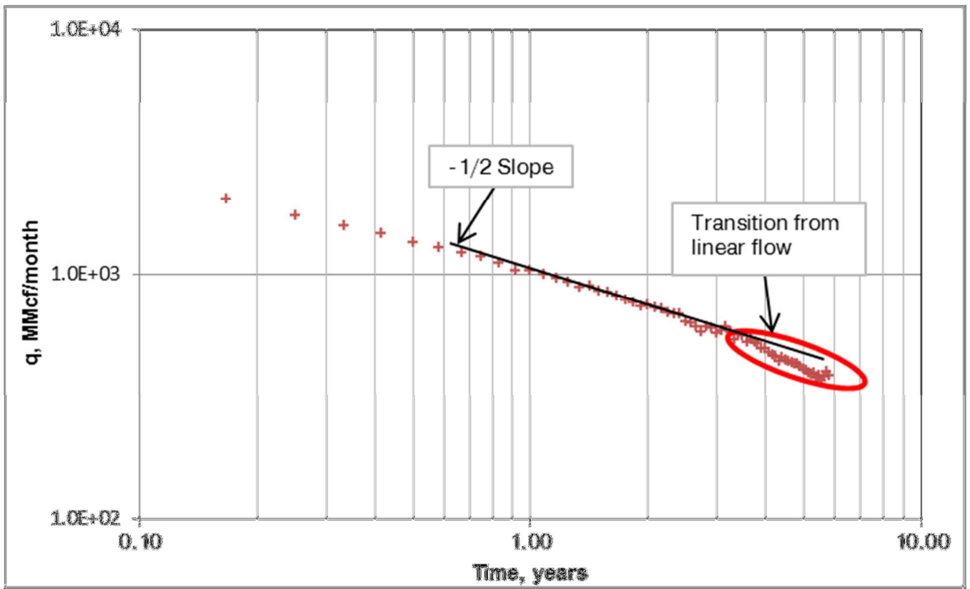

Fig. 10 – For the 2004 Denton County well group, a departure from linear flow occurs around 3 years.

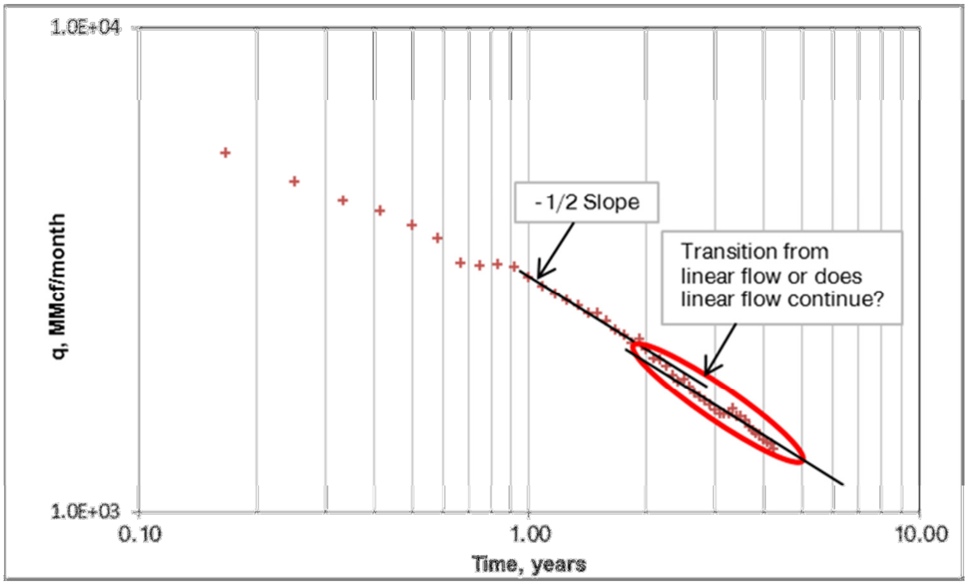

Fig. 11 – It is unclear whether linear flow ends or continues after a change in trend around 2 years for the 2005 Denton County well group; the end of history suggests a transition is likely forthcoming.

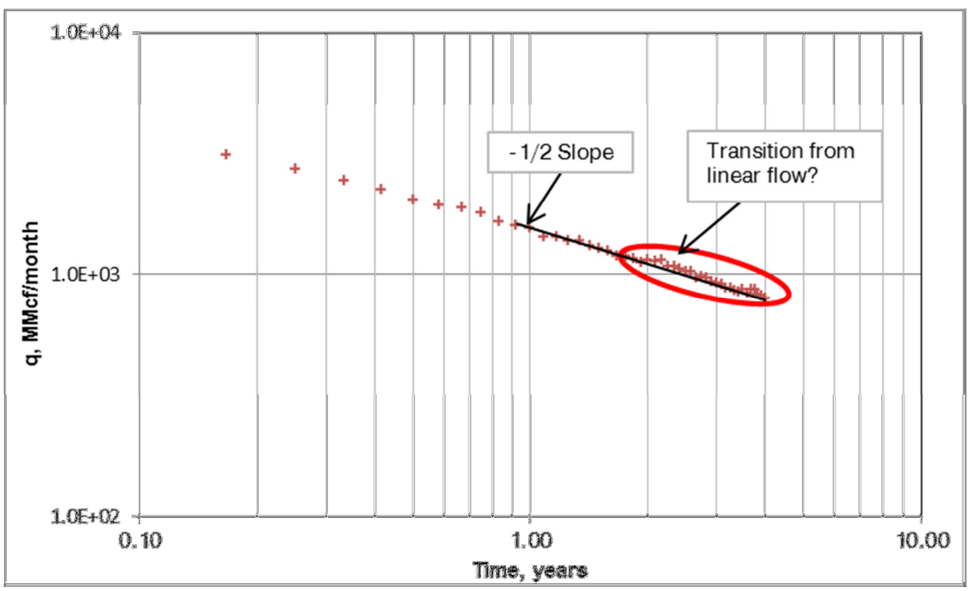

Fig. 12 – For the 2006 Denton County well group, a deviation from linear flow occurs around 2 years but linear flow may resume shortly thereafter.

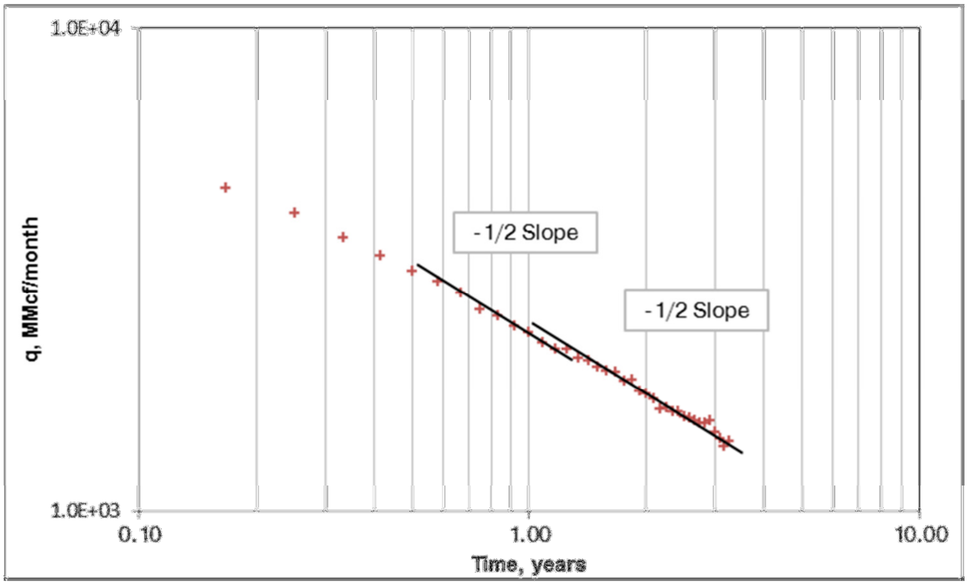

Fig. 13 – The 2007 Denton County well group (113 wells) does not appear to deviate from linear flow before the end of history.

Investigating individual wells with smooth decline profiles gives a good indication of what flow regimes we expect to encounter in Barnett Shale gas wells drilled during and after 2004. Linear flow lasting the life of the well is shown in **Fig. 14** and **Fig. 15** for a Denton County well and a Tarrant County well respectively. **Fig. 16** and **Fig. 17** provide examples of individual wells drilled in Denton County that exhibit a deviation from linear flow and an apparent transition to boundary dominated flow as evidenced by the concave downward shape shortly after the end of linear flow. With only a few examples, we conclude our models will need to handle a wide variety of scenarios. Therefore we test the SEPD model and Arps' model with a minimum decline rate against simulations with linear flow lasting from as short as 1 year to as long as 20 years.

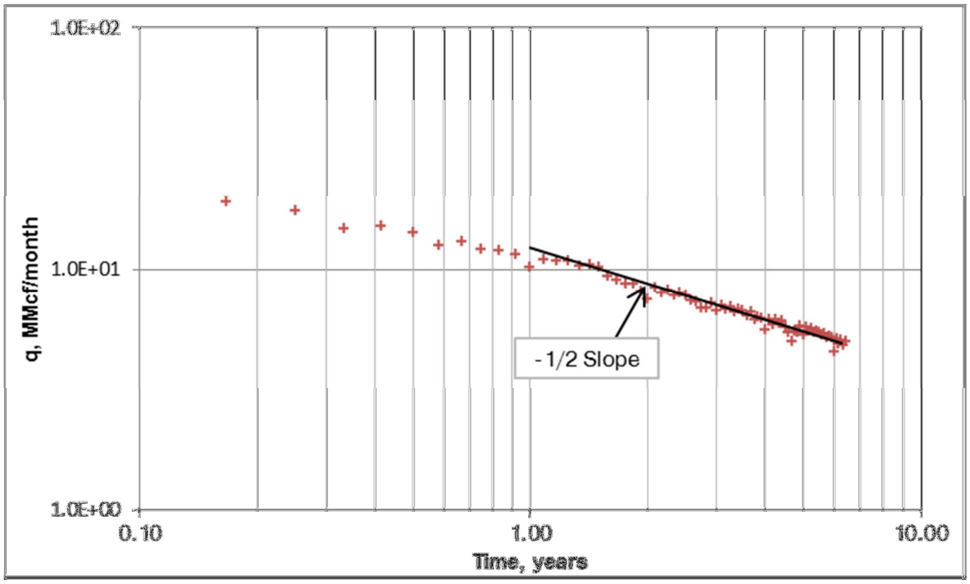

Fig. 14 – Linear flow lasts 6+ years in Denton County well, 42-121-32446.

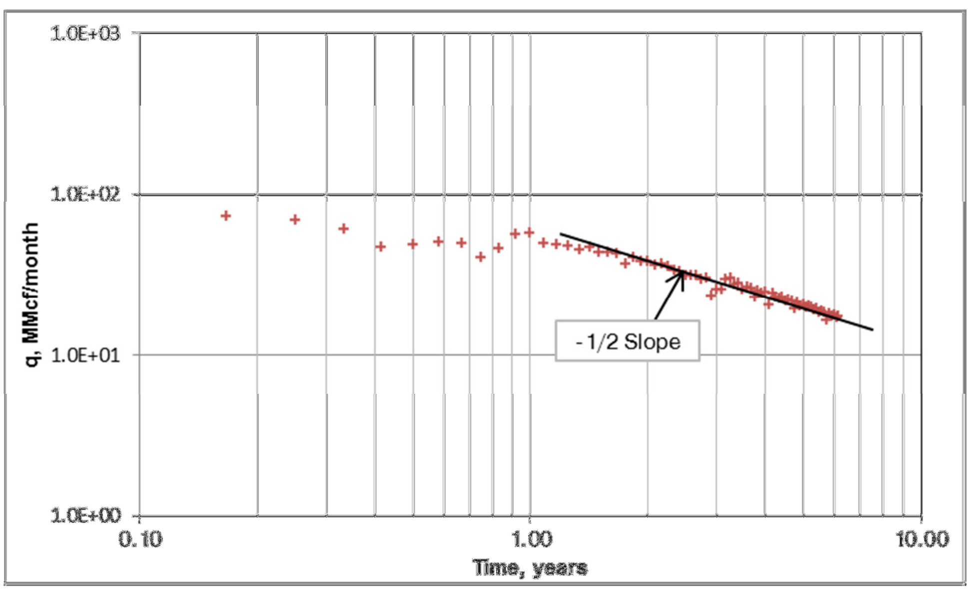

Fig 15 – Tarrant County Barnett Shale well, 42-439-31031, exhibits linear flow for 6+ years.

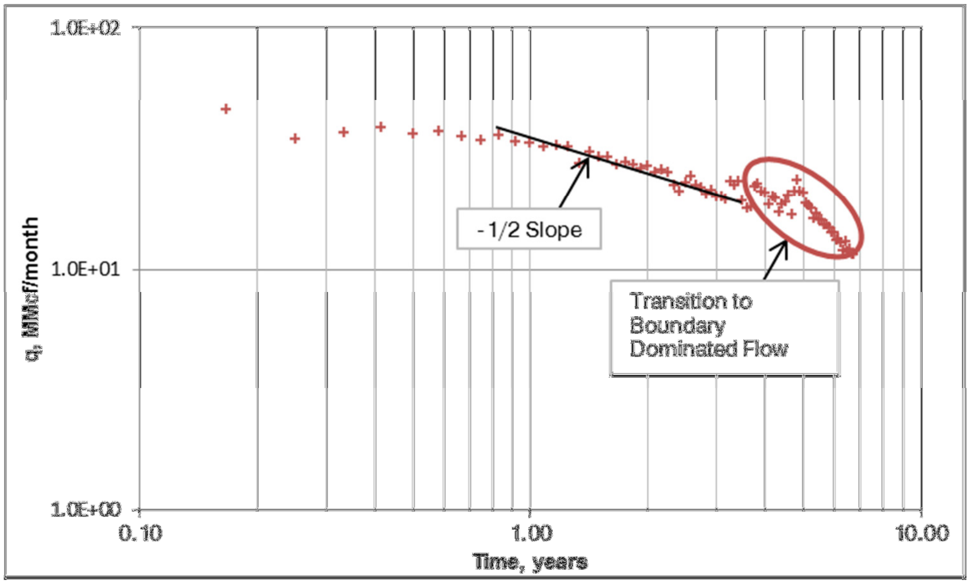

Fig. 16 – Linear flow last for 3 years in Denton County well, 42-121-32159; a transition is seen after an apparent change in operating conditions.

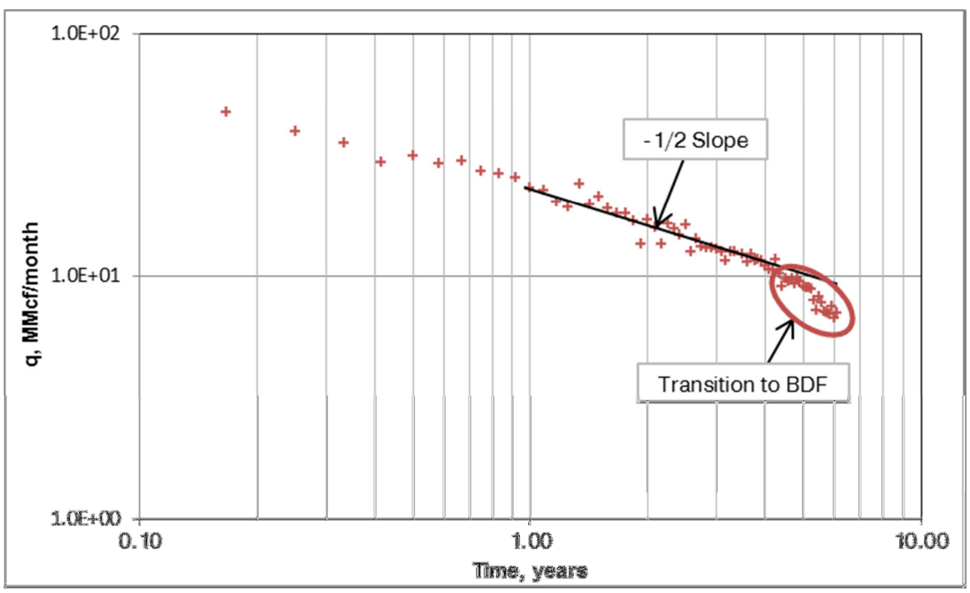

Fig. 17 – Linear flow lasts for 4 years in Denton County well, 42-121-32558; a transition to boundary dominated flow begins evidenced by the concave downward shape starting at year 4.

In this work we do not attempt to model the reservoir complexity of the Barnett Shale noted in literature. Instead we simplify the problem for illustrative purposes and assume a homogeneous reservoir and homogenous hydraulic fractures.

The following five cases are simulated for two different sets of Barnett Shale parameters:

1) Long-term linear flow lasting ~20 years followed by a transition to boundary dominated flow (BDF)
2) Linear flow for ~8 to 10 years followed by a transition to BDF
3) Linear flow for ~5 years followed by a transition to BDF
4) Linear flow for ~2.5 years followed by a transition to BDF
5) Linear flow for ~1 year followed by a transition to BDF

The Horizontal Multi-Fracture Composite Model in Fekete F.A.S.T WellTest™ provides our simulations. For Parameter Set 1, all reservoir properties and parameters except the number of fractures can be found in International Petroleum Technology Conference paper 13185 by Cipolla et al. (Cipolla, Lolon, and Mayerhofer, 2009).

The number of fractures is varied from one case to the next in order to create the five scenarios previously mentioned. We use log-log plots of rate vs. time to establish the end of linear flow – as evidenced by the departure from -1/2 slope.

Table 1 lists Parameter Set 1 properties used for five cases. A bottomhole pressure constraint of 1000 psi is used in all cases. The simulations are run for 30 years or until bottomhole pressure is at equilibrium with reservoir pressure, whichever comes first. It is assumed that flow from outside the stimulated reservoir volume (SRV) is negligible and fracture height is equal to the formation thickness.

Table 1: Parameter Set 1 for Barnett Shale Simulations Based on IPTC 13185

Parameter	Case 1.1	Case 1.2	Case 1.3	Case 1.4	Case 1.5	
Initial Pressure	3000	3000	3000	3000	3000	psi
Frac Half Length	1000	1000	1000	1000	1000	ft
FcD	40	40	40	40	40	-
# Fractures	4	6	9	14	24	
Matrix Perm	0.0001	0.0001	0.0001	0.0001	0.0001	md
Thickness	300	300	300	300	300	ft
Porosity	3	3	3	3	3	%
S_g	70	70	70	70	70	%
x_e	2500	2500	2500	2500	2500	ft
y_e	2000	2000	2000	2000	2000	ft
Fracture Interference Time	20.0	10.0	5.7	2.8	1.3	years

We provide the log-log plot with normalized data for all simulated cases in **Fig. 18**. The end of linear flow and the concave downward shape due to BDF is much easier to distinguish with smooth simulated data. In **Fig. 19**, we take a look at the log-log plot of Cases 1.3, 1.4, and 1.5 and an overlay of the Denton County 2004 well group data (Fig. 10 – transition is around 3 years). It is no surprise the 2004 group decline resembles the decline of Case 1.4 where fracture interference occurs at ~3 years. Next we look at a log-log plot (**Fig. 20**) with normalized data from Cases 1.1, 1.2, and 1.3 combined with an overlay of production data from Denton County well 42-121-32446 (Fig. 14).

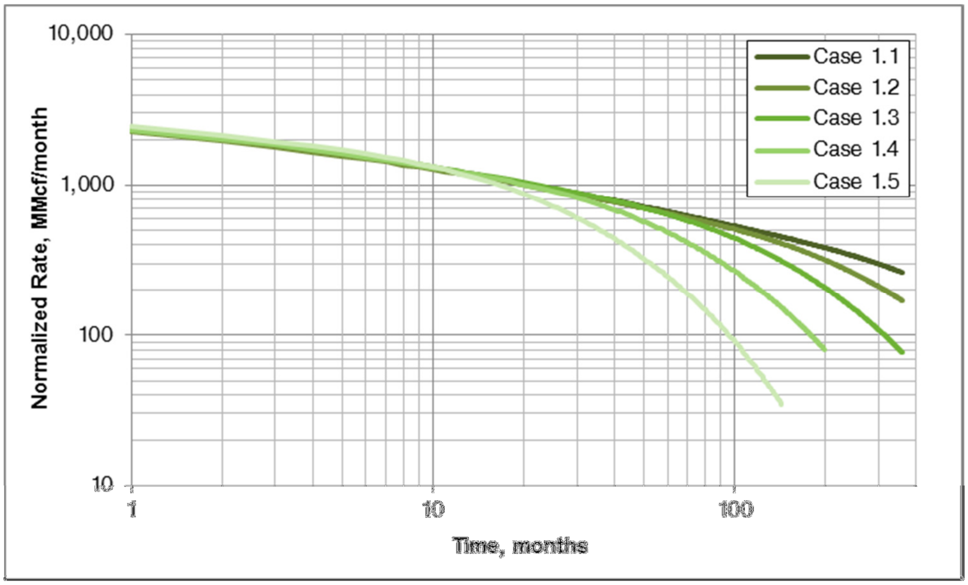

Fig. 18 – Simulated data sets exhibit clear transitions from linear flow to BDF.

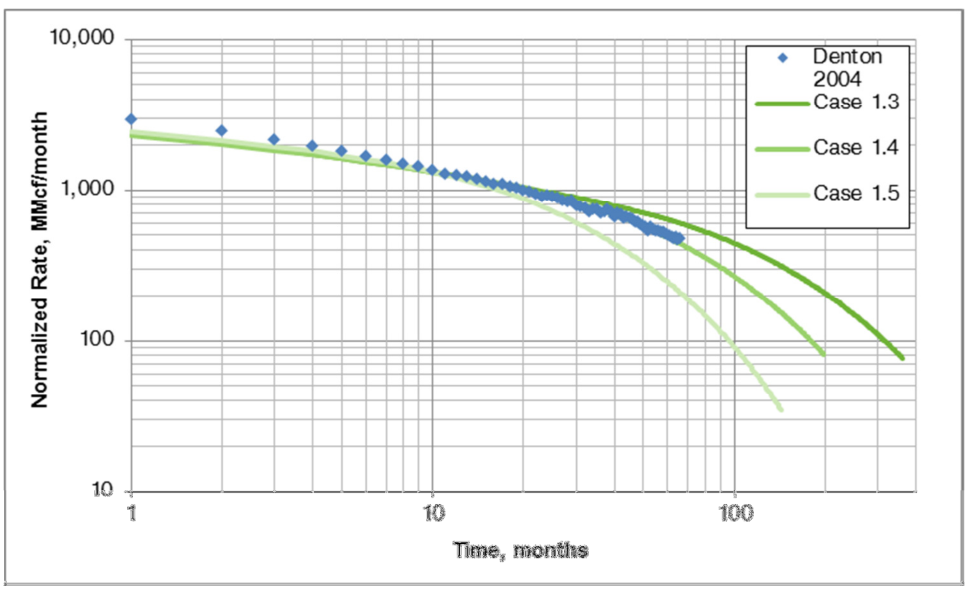

Fig. 19 – 2004 Denton County well group (linear flow ends between 3 and 4 years) exhibits a decline profile most like that of Case 1.4 where linear flow ends at 2.8 years.

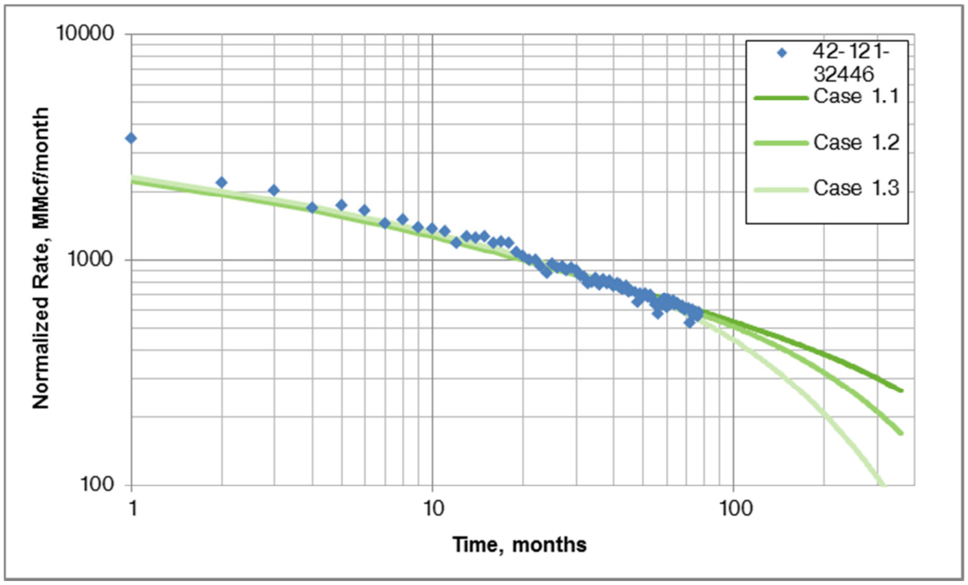

Fig. 20 – Denton County well, 42-121-32446, exhibits long-term linear flow; we cannot establish which case the well is most likely to resemble based on linear flow analysis.

A hindcast is a forecasting procedure where only a portion of the known production history is matched so the remaining production history can be compared against forecasted volumes. Hindcasts are presented in this work with varying amounts of simulated production history used to forecast. The errors between simulated reserves and reserves forecasted by SEPD or Arps' model with a minimum decline rate of 5% are then calculated. **Fig. 21** is an example of several hindcasts for Case 1.1, a long-term linear flow scenario. The cumulative vs. time plot in **Fig. 22** shows that the SEPD model will converge to a near perfect EUR match for the long-term linear flow scenario. Another important observation is the rate forecasts start conservative and work upward towards the simulated decline behavior.

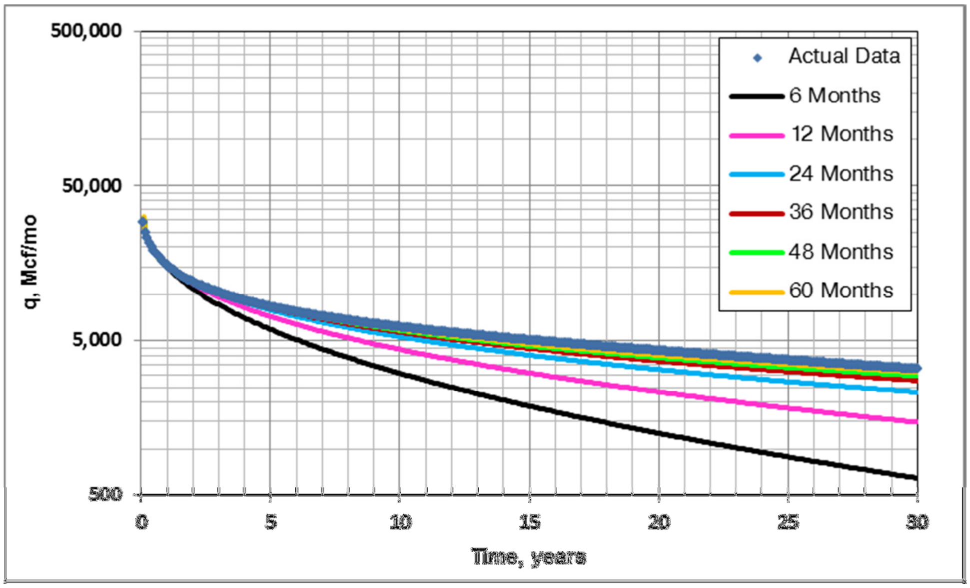

Fig. 21 – For Case 1.1 (long-term linear flow), the SEPD model forecasts reserves within 10% of the simulated values using 36 months of data or greater.

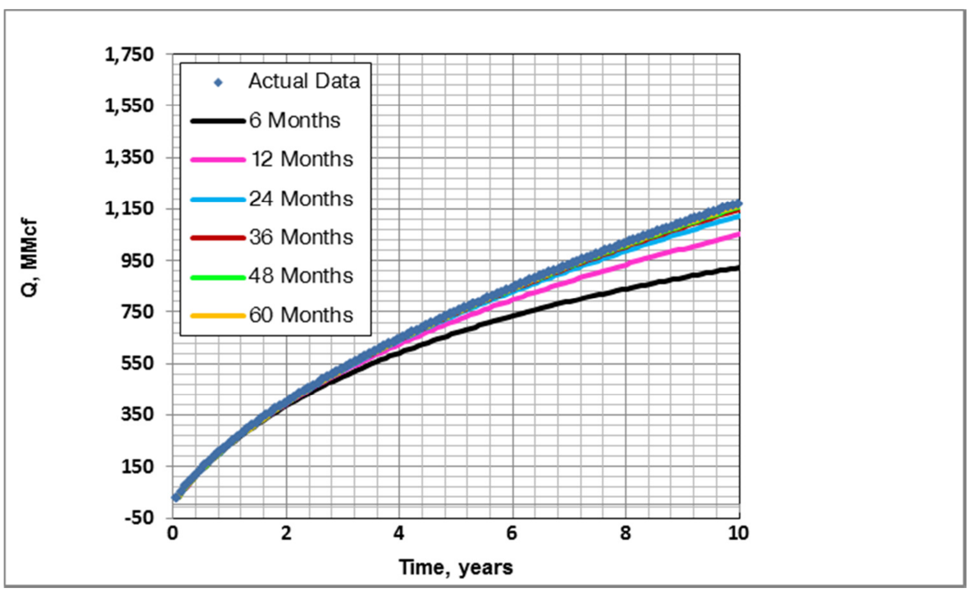

Fig. 22 – With 60 months of simulated data used to forecast the 30 year EUR, a near perfect forecast is achieved for Case 1.1 using the SEPD model.

Fig. 23 shows the error in reserves for Case 1.1 forecasts using the SEPD model and Arps' model with a minimum decline rate of 5%. Positive errors equate to reserves being underestimated. Conversely, negative errors mean reserves are being overestimated. Arps' minimum decline model gives the best estimate when less than 36 months of data is available but diverges to a maximum error of 12% when up to 120 months of data is used. The SEPD model provides very conservative estimates with less than 24 months of data but converges within ±4% error in reserves when 60 months or more is used to forecast. Plots for the error in the estimated ultimate recovery (EUR) can be found in **Appendix A**. We prefer to focus on the ability of the models to forecast reserves rather than their ability to fit data that has already occurred. In shale gas wells, large production rates are often seen early in the life of a well. Considering data prior to the forecasting period can lead us to a false belief that error in reserves is low.

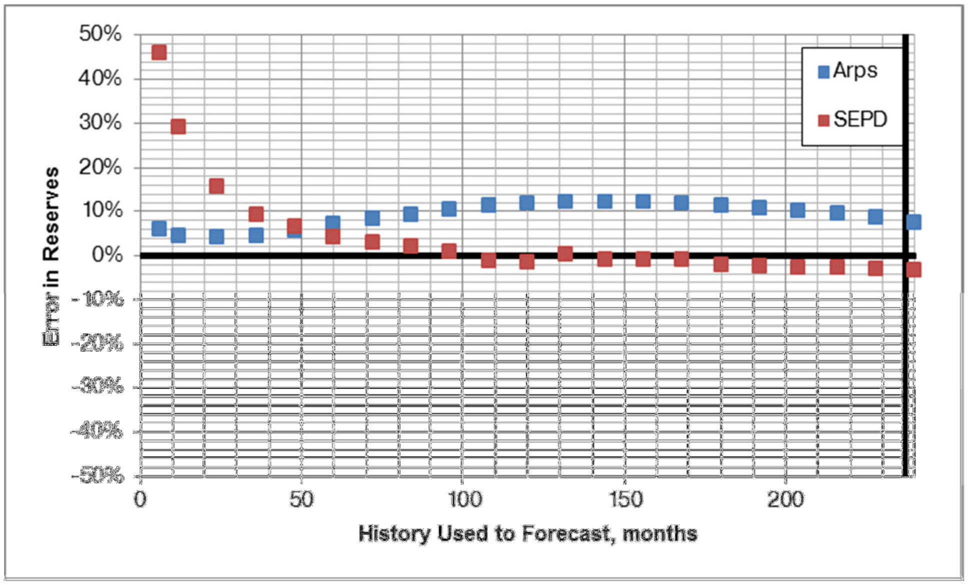

Fig. 23 – For Case 1.1, SEPD starts off conservative and converges to within 5% of the true solution with 60 months of history used; Arps with a 5 % minimum decline starts off closer to the true solution but ends up being more conservative as more history is used.

Unlike Case 1.1, the fracture interference time for Case 1.2 is seen much earlier in history (vertical black bar in figures) and occurs around the 10 year mark. **Fig. 24** shows SEPD converging up to 24 months and diverging slightly for subsequent forecasts up to 60 months. Looking at the error in the reserves, **Fig. 25,** we see SEPD reserves errors again start conservative leveling out around -13% until beginning to gradually converge when 132 months or more is available to forecast. Both models are within ±15% when 24 months or more is available to forecast. In Cases 1.1 and 1.2, SEPD and Arps' model with a minimum decline rate of 5% both give acceptable reserves forecasts. The SEPD model shows the ability to converge to the most accurate forecast. For Case 1.2, Arps' model with a minimum decline rate is more accurate with 24 months of data or less and remains the better of the two models until late in the life of the well. That being said, both models have narrow error ranges (±15%) with 24 months or more available to forecast.

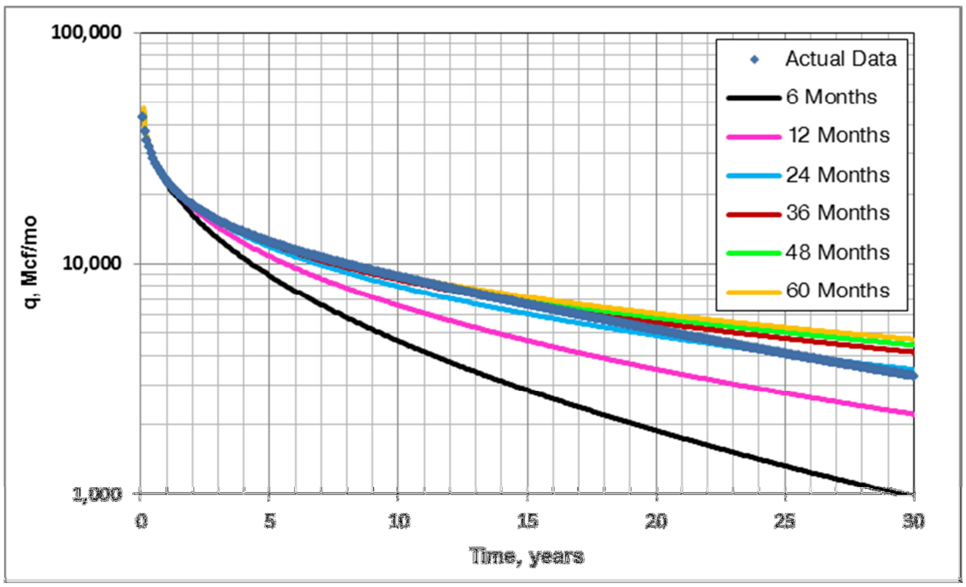

Fig. 24 – For Case 1.2, SEPD forecasts start conservative but begin to overestimate slightly when 36 months or greater is used.

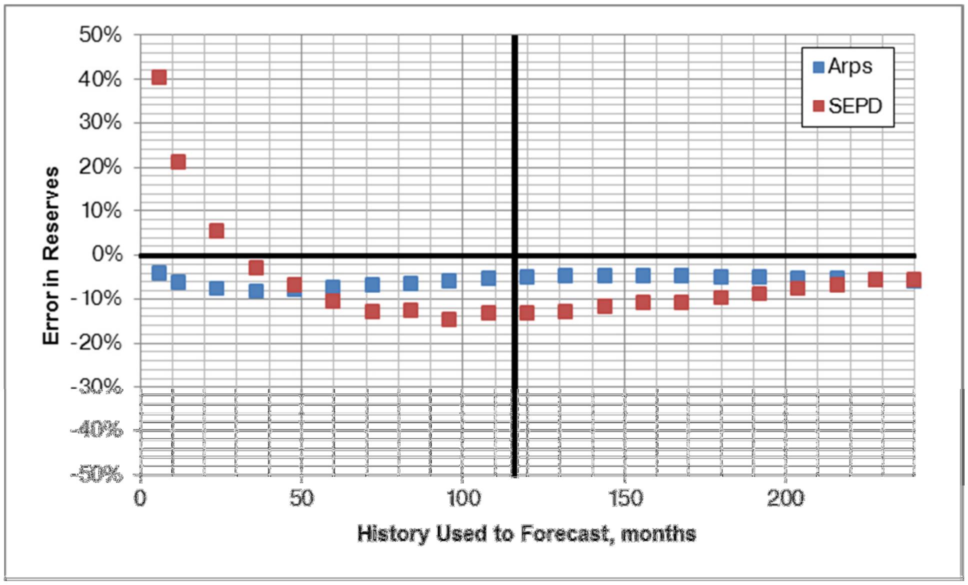

Fig. 25 – With fracture interference occurring at 10 years, SEPD again gives conservative estimates early; both models are within -15% using 24 months of data or more (Case 1.2).

The first two cases represented relatively long periods of linear flow. As previously mentioned, natural fracturing is known to be prevalent in much of the Barnett Shale resulting in high initial rates. Periods of linear flow may or may not last as long as those seen in Cases 1.1 and 1.2 - we can confirm that linear flow ends earlier in many 2004 wells. When attempting to quantify the uncertainty in Barnett Shale forecasts, we feel Cases 1.3 and 1.4 are likely to represent the type of behavior that will be exhibited in wells with large fracture treatments. Cases 1.1 and 1.2 provide valuable information on how the models are likely to respond when applied to reservoirs where long-term linear flow occurs. Further, long-term linear flow is matched relatively well by both models so they should provide accurate estimates for individual wells exhibiting long-term linear flow.

Fracture interference occurs at 5 years in Case 1.3 and as intuition might suggest, the SEPD model does not predict a change prior to the transition from linear flow to boundary dominated flow (**Fig. 26).** The error in reserves (**Fig. 27**), show SEPD provides better estimates for the life of the simulation relative to Arps' model with a minimum decline rate of 5% but SEPD does not begin converging towards the true simulated values until 60 months or more is used to forecast. An error range of ±15% is not reached until ~108 months or more is used with SEPD and 228 months or more is used for Arps' model with a minimum decline of 5%. Note the SEPD reserves forecasts in this case are all more conservative and more accurate than Arps' model with a minimum decline rate of 5%.

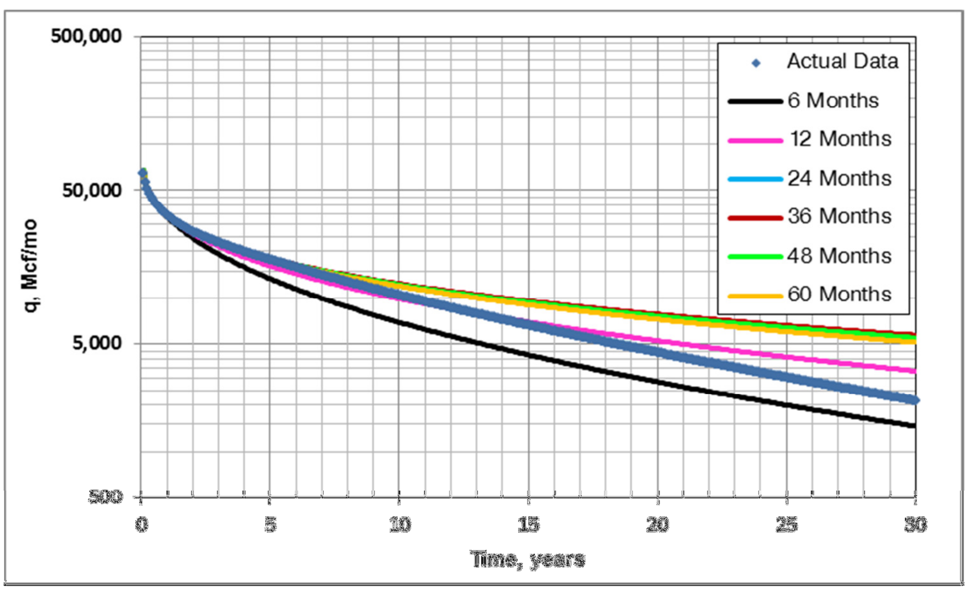

Fig. 26 – SEPD begins overestimating reserves with 12 months of data until a maximum error of -35% with 48 months used to forecast.

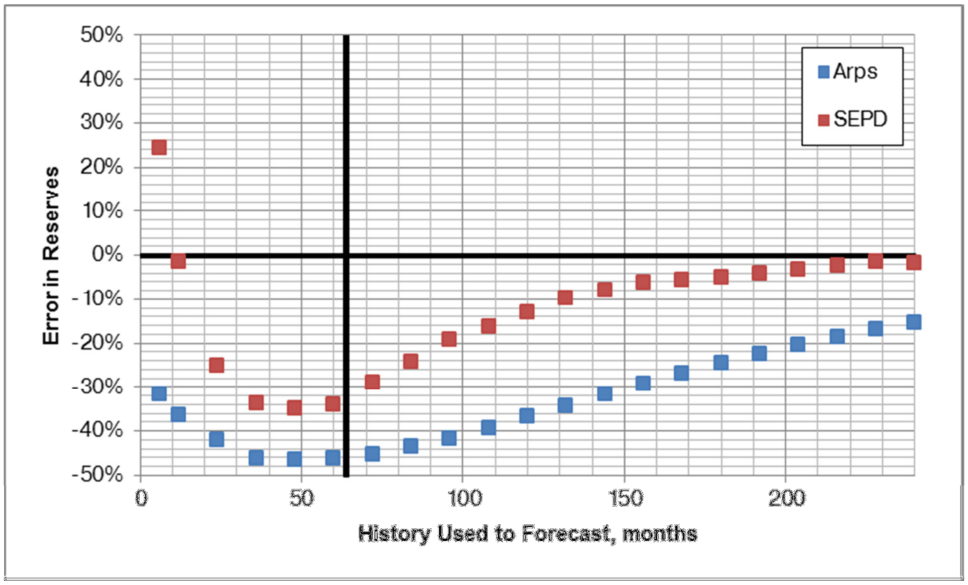

Fig. 27 – Neither model provides consistently reliable results until after fracture interference occurs (Case 1.3).

Recall Case 1.4 with a fracture interference time of 2.8 years appears by visual inspection to have a similar decline profile to the 2004 Denton County yearly well group. **Fig. 28** shows the SEPD model quickly converging towards the true simulated decline. Investigating the error in reserves in **Fig. 29**, we see the SEPD model provides more conservative forecasts than Arps' early on and provides more accurate forecasts for the remainder of the life of the simulation. Both models overestimate reserves by a great deal early with SEPD converging from a maximum error of -55% using 24 months of data to within -14% using 60 months. With 84 months or greater available, SEPD provides reserves estimates within a -5% to 0% window. Arps' model with a minimum decline rate of 5% reaches a maximum error of 105% at 24 months and first provides an estimate within -15% error when 192 months of data or greater are available.

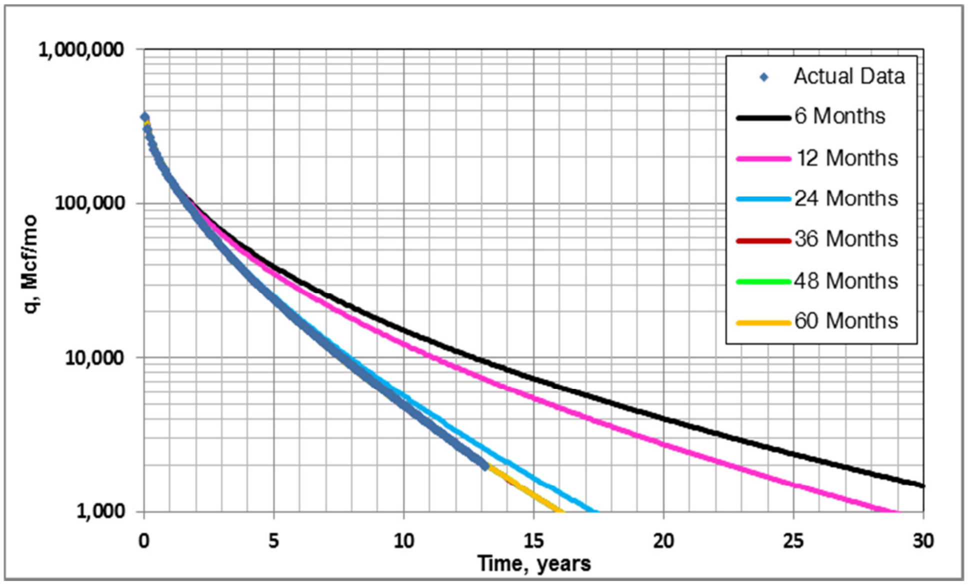

Fig. 28 – SEPD model overestimates early on for Case 1.4 where fracture interference is seen at 2.9 years and begins to converge towards the true decline behavior forecasting reserves within -15% when 60 months of data is used.

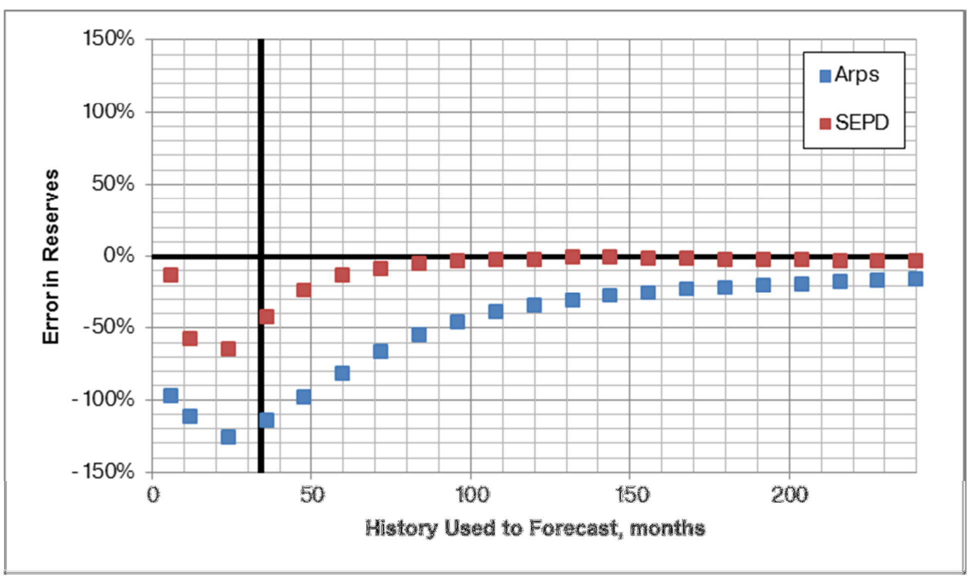

Fig. 29 – SEPD provides better reserves estimates for the entire life of the simulation with a maximum error of -55% when 24 months of data is used (Case 1.4).

For the final case using Parameter Set 1, linear flow is designed to last for only a period of 1.3 years. The reserves estimates for the SEPD model converge relatively quickly, **Fig. 30,** and with 24 months of data or more the model achieves error in reserves of -5% or less. Arps' model with a minimum decline of 5% is within the ±15% window when 120 months or greater is used. With 6 months of data, Arps is off by -155%. We note both models overestimate reserves early instead of underestimate as the United States Securities and Exchange Commission would prefer (**Fig. 31**).

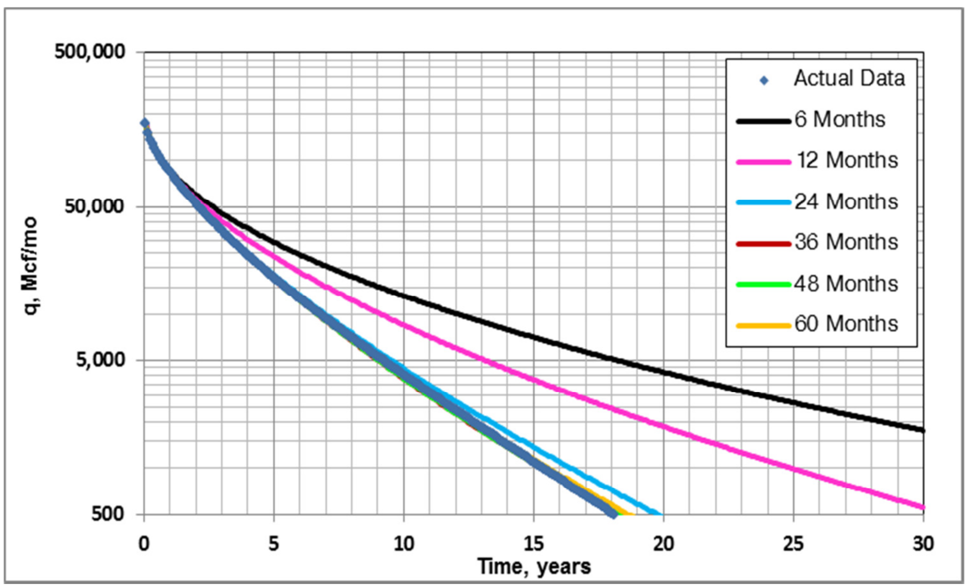

Fig. 30 – For Case 1.5 where linear flow lasts only 1.3 years, the SEPD model converges to the correct forecast quicker than any of the previous cases achieving a reserves estimate with just -5% error using 24 months of data.

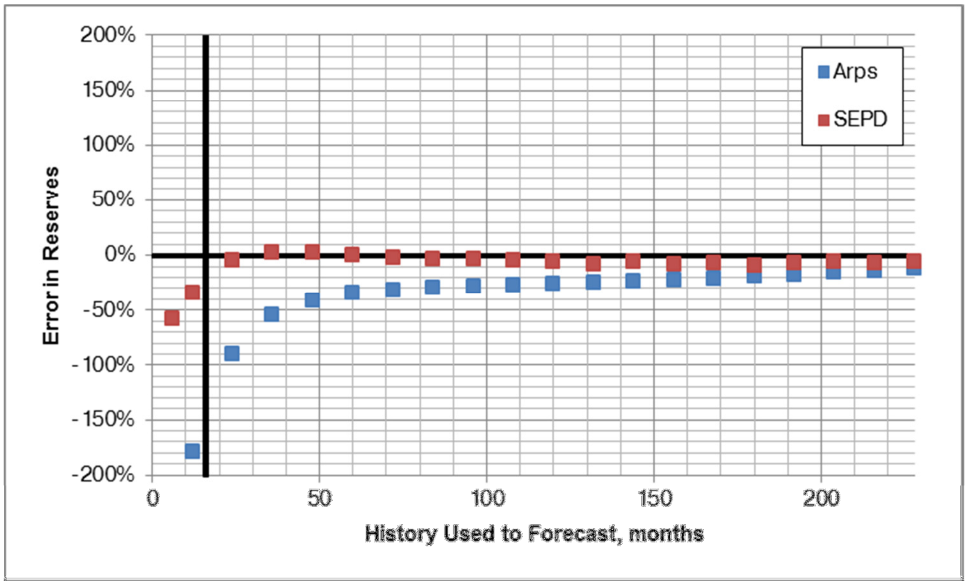

Fig. 31 – SEPD converges quickly to the correct forecast while Arps with a minimum decline overestimates reserves significantly early and does not converge within -15% until 120 months of data or greater is used (Case 1.5).

3.2 Barnett Shale Simulated: Parameter Set 2

The second set of parameters used for Barnett Shale simulations is based on those found in SPE 125530 by Cipolla et al (Cipolla, Lolon, Erdle, et al., 2009). **Table 2** provides the parameters used with the number of fractures being the only variable. The main differences between Parameter Set 1 and Parameter Set 2 are the permeability is lower by an order of magnitude, fracture conductivity is increased by five times, and the length of the well is increased.

Table 2 – Properties for Parameter Set 2 Based on SPE 125530

Parameter	Case 2.1	Case 2.2	Case 2.3	Case 2.4	Case 2.5	
Initial Pressure	3800	3800	3800	3800	3800	psi
Frac Half Length	1000	1000	1000	1000	1000	ft
FcD	200	200	200	200	200	-
# Fractures	14	21	30	47	80	
Matrix Perm	0.00001	0.00001	0.00001	0.00001	0.00001	md
Thickness	300	300	300	300	300	ft
Porosity	3	3	3	3	3	%
S_g	70	70	70	70	70	%
x_e	3000	3000	3000	3000	3000	ft
y_e	2000	2000	2000	2000	2000	ft
Fracture Interference Time	17.5	8.3	5.0	2.2	1.0	years

We start our analysis of models using Parameter Set 2 with the long-term linear flow case. Case 2.1, **Fig. 32**, shows the ability of the SEPD model to converge within 17% error in reserves with 24 months of data and 8% with 36 months of data. The estimates start conservative and work their way up to the true simulated values.

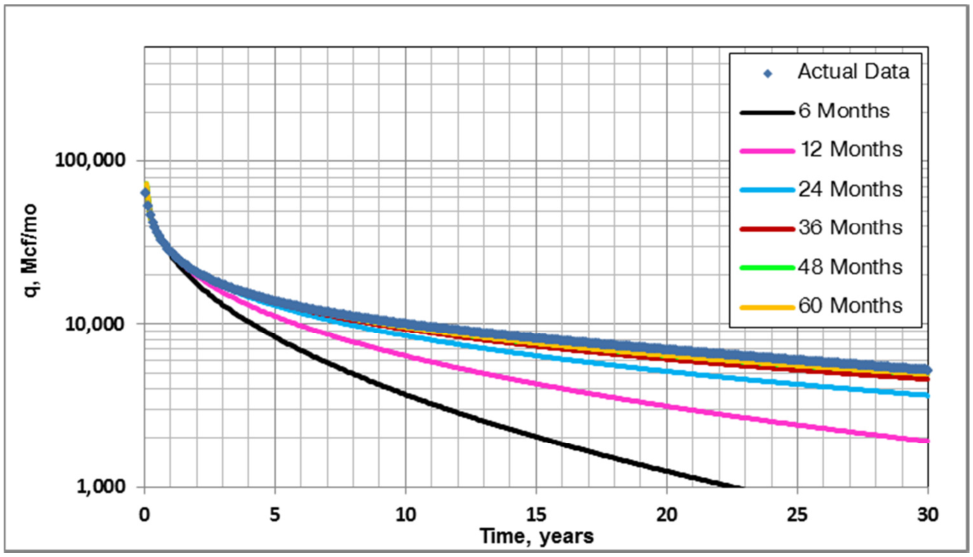

Fig. 32 – SEPD model converges quickly for long-term linear flow Case 2.1.

Arps' model with a minimum decline rate of 5% gives estimates within 5% of the simulated reserves when 36 months of data or less is used. The SEPD model provides rather conservative estimates with less than 36 months of data used. As seen in **Fig. 33**, when more than 36 months is used, SEPD provides more accurate reserves estimates for all subsequent forecasts.

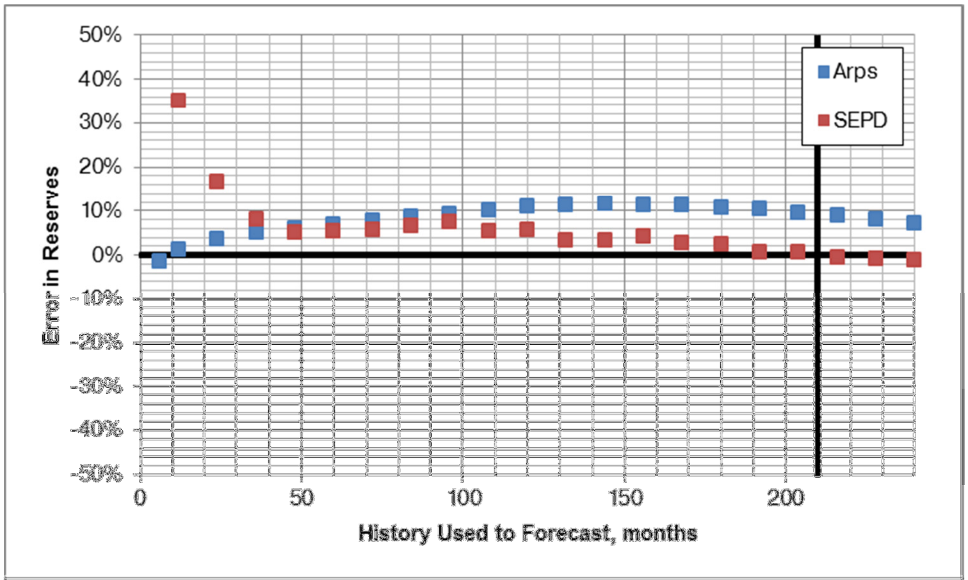

Fig. 33 – In Case 2.1 where linear flow lasts for 17.5 years, the SEPD model starts off quite conservative and converges to within 15% of the actual simulated reserves when 36 months or greater is used; Arps' model with a minimum decline rate of 5% provides very accurate reserves estimates early and diverges slightly as more data becomes available to forecast.

Case 2.2 provides another relatively long-term linear flow case with linear flow lasting 8.3 years. Similar to Case 1.2, the SEPD reserves estimates start off conservative but after 24 months, the forecasts begin to diverge from the simulated values, particularly later in the life of the well (**Fig. 34**). Error in reserves estimates remain within 15% of the true value for both models when 24 months or greater is used (**Fig. 35**). With 24 months of data or less available, Arps' model with a minimum decline rate gives more accurate reserves forecasts than the SEPD model.

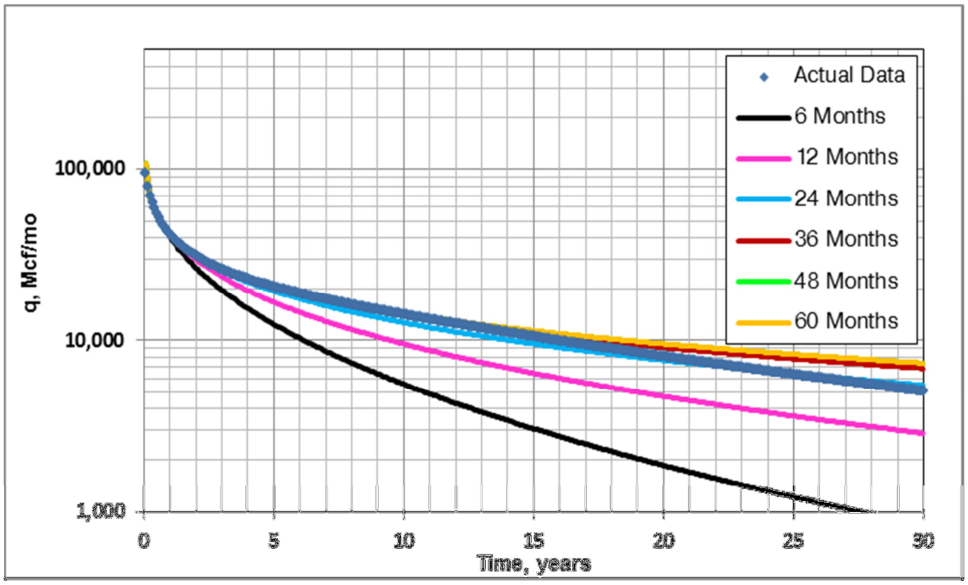

Fig. 34 – Case 2.2 with a fracture interference time of 14.9 years causes the SEPD model to diverge slightly when 36 to 60 months is used; reserves estimates stay within ±15% of the true value when forecasting with 24 months or greater.

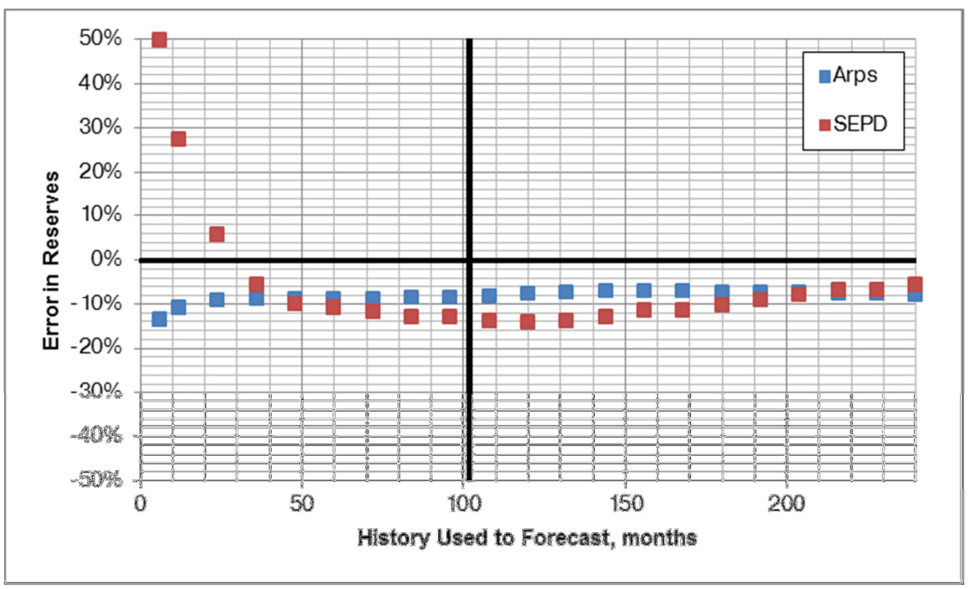

Fig. 35 – SEPD model starts off with very conservative reserves estimates in Case 2.2 while Arps starts off slightly overestimating reserves; both models provide error in reserves of -15% or less when 24 months or greater is used to forecast.

With a fracture interference time of 5 years, Case 2.3 poses problems for the SEPD model early. Similar to the previous case, early reserves estimates are conservative but when more than 12 months of data is used, the forecasts begin diverging and reserves are overestimated (**Fig. 36**). As seen in **Fig. 37**, Arps' model with a minimum decline rate of 5% gives less accurate forecasts than the SEPD model for the duration of the simulation. While the SEPD model does not provide the accuracy we are hoping for (within ±15%) early on, when 48 months or greater is used, the model begins to converge towards the true solution and is within -15% error when 120 months or more is used. Within the first 240 months, Arps' model with a minimum decline rate does not provide a reserves forecast within ±15% of the simulated values.

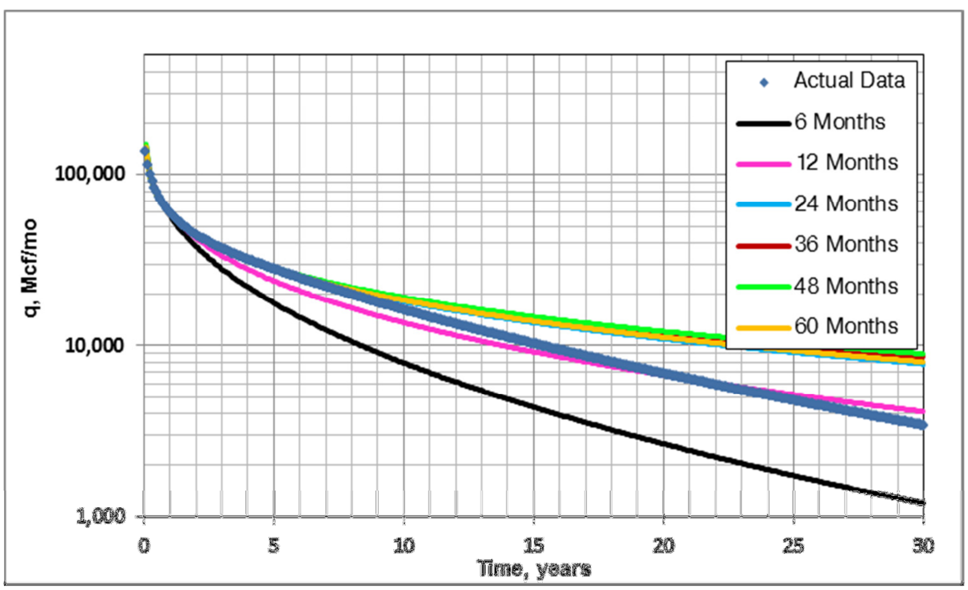

Fig. 36 – For Case 2.3, the SEPD model does not converge within the first 60 months.

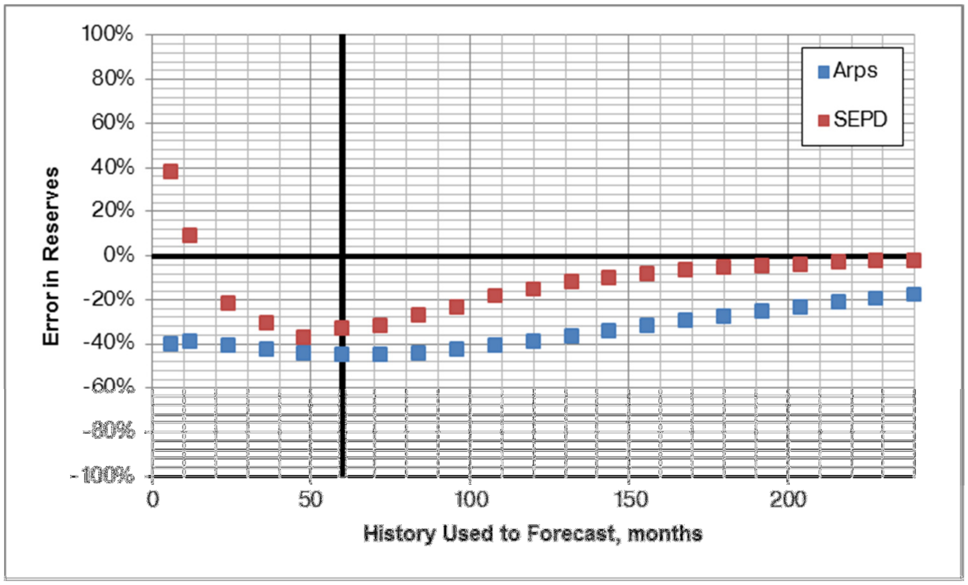

Fig. 37 – Arps' model with a minimum decline rate of 5% does not handle Case 2.3 well at all while the SEPD model does not do much better until a significant portion of the history is available to forecast.

Linear flow lasts 2.2 years in Case 2.4 and the SEPD model transitions from underestimating to overestimating reserves early before starting to converge towards the true solution when 24 months or greater is used to forecast (**Fig. 38**). An error in reserves of -14% occurs using 60 months with SEPD and the model converges to within -5% error in reserves when 72 months or greater is used (**Fig. 39**). Arps' model with a minimum decline starts off overestimating by over 100% and converges within -15% of the actual reserves when 192 months or more is used to forecast.

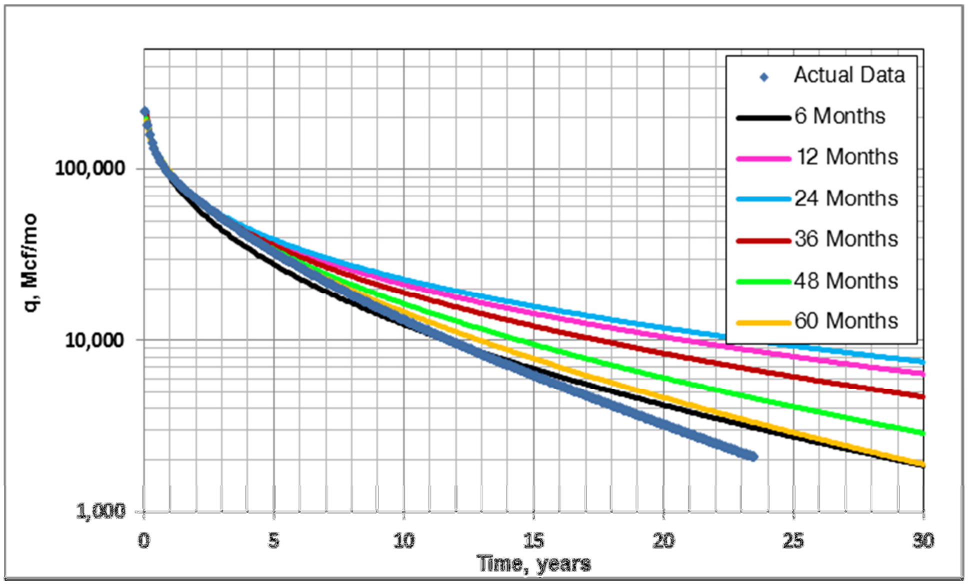

Fig. 38 – For Case 2.4, the SEPD model overestimates initially but begins converging to the true solution.

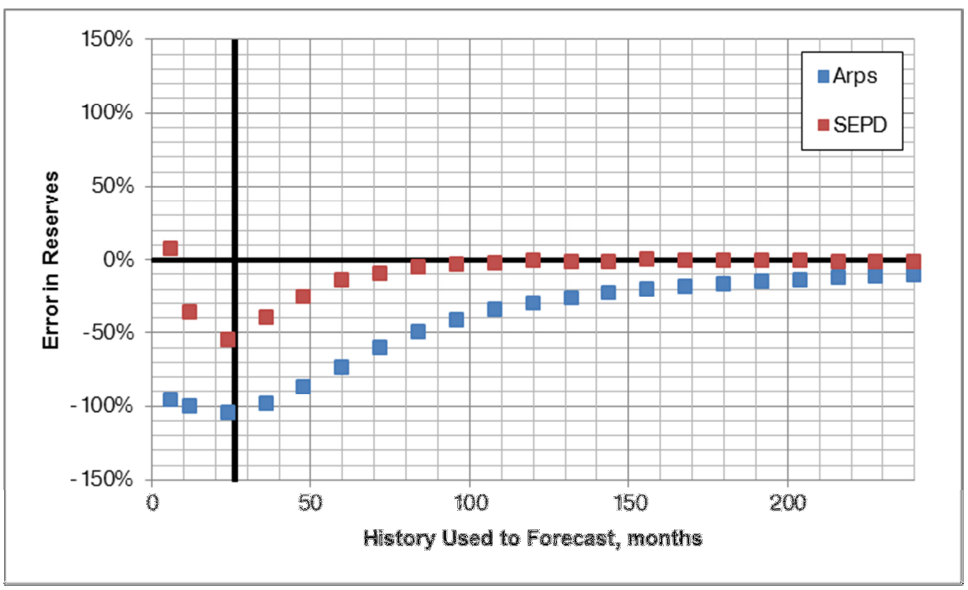

Fig. 39 – The SEPD model is more accurate than Arps' model with a minimum decline rate from start to finish for Case 2.4 with fracture interference occurring around 2.2 years.

The final case for Parameter Set 2, Case 2.5, has a fracture interference time of 1 year and the SEPD model is able to converge to the true solution relatively quickly as shown in **Fig. 40**. With 24 months of data, the SEPD model forecasts reserves within -5% of the actual value while Arps' model with a minimum decline rate greatly overestimates reserves in the first year and overestimates by 72% when 24 months of data is available (**Fig. 41**). The SEPD model forecasts reserves near perfection with 36 months of data or more available to forecast. Arps' model with a minimum decline rate forecasts reserves within -15% for the first time when 108 months of data is available.

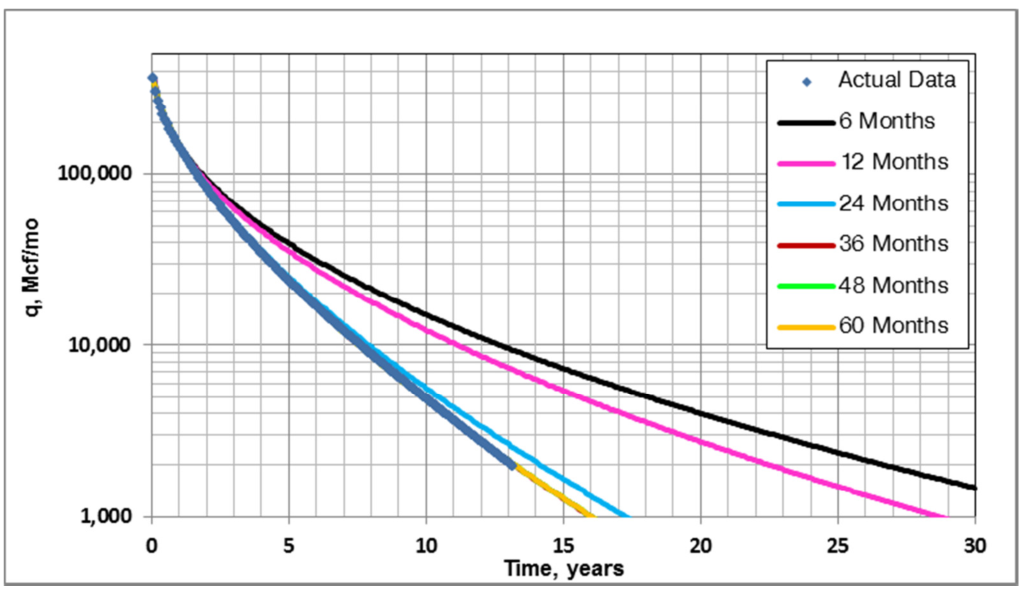

Fig. 40 – The SEPD model converges quickly to the correct solution for short-term linear flow Case 2.5.

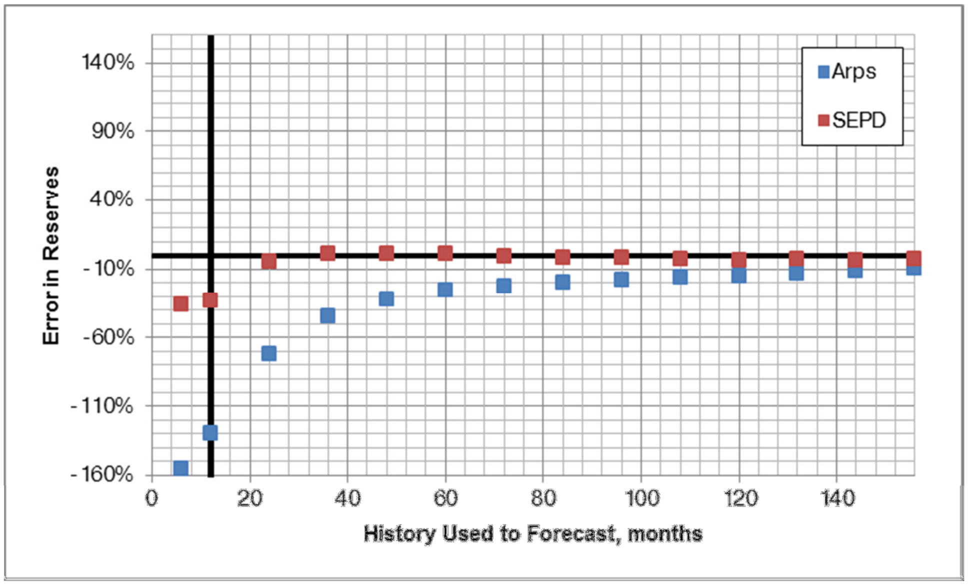

Fig. 41 – For Case 2.5, the SEPD clearly provides better reserves estimates throughout the entire simulated life; Arps with a minimum decline rate overestimates reserves by a significant amount when less than 36 months of data is available.

3.3 Summary and Discussion of Simulation Results

Barnett Shale field data suggests linear flow may last as short as 3 years. The data does not provide any kind of upper limit on the time that wells typically transition out of linear flow – several wells exhibit linear flow to the end of history (6+ years). Between the two sets of parameters, we looked at 10 different cases with linear flow periods lasting 20 years down to as short as 1 year. **Table 3** provides a summary of the error in reserves for both models using Parameter Set 1. **Table 4** provides a summary of the error in reserves for Parameter Set 2. For cases where linear flow lasts longer than 8 years, the SEPD model gives very conservative estimates early and provides accurate (within ±15%) reserves estimates when 36 months or greater is used to forecast. Arps' model with a minimum decline rate of 5% performs better in these cases when 24 months or less is available to forecast and performs similarly when 36 months or greater is used.

Table 3 – SEPD and Arps' Error in Reserves for Parameter Set 1 Simulations

Months Used to Forecast	Case 1.1 SEPD	Case 1.1 Arps 5%	Case 1.2 SEPD	Case 1.2 Arps 5%	Case 1.3 SEPD	Case 1.3 Arps 5%	Case 1.4 SEPD	Case 1.4 Arps 5%	Case 1.5 SEPD	Case 1.5 Arps 5%
6	46%	**6%**	40%	**-4%**	**24%**	-32%	**-14%**	-98%	**-58%**	-202%
12	29%	**4%**	21%	**-6%**	**-1%**	-36%	**-57%**	-112%	**-34%**	-179%
24	16%	**4%**	**5%**	-8%	**-25%**	-42%	**-65%**	-126%	**-5%**	-89%
36	9%	**5%**	**-3%**	-8%	**-34%**	-46%	**-43%**	-115%	**2%**	-54%
48	7%	**6%**	**-7%**	-8%	**-35%**	-47%	**-24%**	-99%	**2%**	-41%
60	**4%**	7%	-11%	**-7%**	**-34%**	-46%	**-14%**	-82%	**0%**	-35%
72	**3%**	8%	-13%	**-7%**	**-29%**	-45%	**-8%**	-67%	**-2%**	-31%
84	**2%**	9%	-13%	**-6%**	**-24%**	-44%	**-5%**	-55%	**-3%**	-29%
96	**1%**	10%	-15%	**-6%**	**-19%**	-42%	**-4%**	-46%	**-4%**	-28%
108	**-1%**	11%	-13%	**-5%**	**-16%**	-39%	**-2%**	-39%	**-5%**	-27%
120	**-1%**	12%	-13%	**-5%**	**-13%**	-37%	**-3%**	-34%	**-6%**	-26%
132	**0%**	12%	-13%	**-5%**	**-10%**	-34%	**-1%**	-31%	**-8%**	-25%
144	**-1%**	12%	-12%	**-5%**	**-8%**	-32%	**-1%**	-28%	**-6%**	-24%
156	**-1%**	12%	-11%	**-5%**	**-6%**	-29%	**-2%**	-25%	**-8%**	-22%
168	**-1%**	12%	-11%	**-5%**	**-6%**	-27%	**-2%**	-23%	**-7%**	-21%
180	**-2%**	11%	-10%	**-5%**	**-5%**	-25%	**-2%**	-22%	**-9%**	-19%
192	**-2%**	11%	-9%	**-5%**	**-4%**	-22%	**-2%**	-20%	**-8%**	-18%
204	**-3%**	10%	-8%	**-5%**	**-3%**	-20%	**-3%**	-19%	**-6%**	-16%
216	**-3%**	9%	-7%	**-5%**	**-2%**	-19%	**-3%**	-18%	**-8%**	-14%
228	**-3%**	9%	-6%	-6%	**-1%**	-17%	**-3%**	-17%	**-6%**	-12%
240	**-3%**	8%	-6%	-6%	**-2%**	-15%	**-4%**	-16%		

Table 4 – SEPD and Arps' Error in Reserves for Parameter Set 2 Simulations

Months Used to Forecast	Case 2.1 SEPD	Case 2.1 Arps 5%	Case 2.2 SEPD	Case 2.2 Arps 5%	Case 2.3 SEPD	Case 2.3 Arps 5%	Case 2.4 SEPD	Case 2.4 Arps 5%	Case 2.5 SEPD	Case 2.5 Arps 5%
6	55%	**-1%**	50%	**-14%**	**38%**	-40%	**7%**	-96%	**-36%**	-155%
12	35%	**1%**	27%	**-11%**	**9%**	-39%	**-37%**	-101%	**-33%**	-129%
24	17%	**4%**	6%	**-9%**	**-22%**	-41%	**-55%**	-105%	**-5%**	-72%
36	8%	**5%**	**-5%**	-9%	**-31%**	-43%	**-40%**	-99%	**1%**	-44%
48	**5%**	6%	-10%	**-9%**	**-37%**	-44%	**-25%**	-87%	**1%**	-32%
60	**5%**	7%	-11%	**-9%**	**-33%**	-45%	**-14%**	-73%	**1%**	-26%
72	**6%**	8%	-12%	**-9%**	**-32%**	-45%	**-10%**	-60%	**-1%**	-22%
84	**7%**	9%	-13%	**-9%**	**-27%**	-44%	**-5%**	-50%	**-2%**	-20%
96	**7%**	9%	-13%	**-8%**	**-24%**	-43%	**-4%**	-41%	**-2%**	-18%
108	**5%**	10%	-14%	**-8%**	**-19%**	-41%	**-3%**	-35%	**-3%**	-16%
120	**6%**	11%	-14%	**-8%**	**-15%**	-39%	**-1%**	-30%	**-4%**	-15%
132	**3%**	11%	-14%	**-7%**	**-12%**	-37%	**-1%**	-26%	**-3%**	-13%
144	**3%**	11%	-13%	**-7%**	**-10%**	-35%	**-2%**	-23%	**-4%**	-11%
156	**4%**	11%	-12%	**-7%**	**-8%**	-32%	**0%**	-21%	**-3%**	-9%
168	**3%**	11%	-11%	**-7%**	**-6%**	-30%	**0%**	-19%		
180	**3%**	11%	-10%	**-7%**	**-6%**	-28%	**-1%**	-17%		
192	**1%**	10%	-9%	**-7%**	**-5%**	-25%	**-1%**	-15%		
204	**1%**	10%	-8%	**-7%**	**-4%**	-23%	**-1%**	-14%		
216	**-1%**	9%	**-7%**	-8%	**-3%**	-21%	**-1%**	-13%		
228	**-1%**	8%	**-7%**	-8%	**-2%**	-20%	**-1%**	-12%		
240	**-1%**	7%	**-6%**	-8%	**-3%**	-18%	**-2%**	-11%		

A problem arises for both models when attempting to forecast simulation Cases 1.3 and 2.3 where linear flow lasts ~5 years. Neither the SEPD model nor Arps' model with a minimum decline rate give consistently accurate reserves forecasts until substantial history is available to forecast. Errors within -15% are not achieved until after the time of fracture interference. This is concerning from a reserves analyst perspective since both models over predict reserves for the life of the simulation and by as much as -47% with 48 months of data available to forecast. In both cases, SEPD predicts reserves more accurately than Arps' model with a minimum decline rate of 5%.

With relatively short periods of linear flow lasting 2.5 years or less, SEPD clearly gives better reserves estimates than Arps' model with a minimum decline rate of 5%.

With 60 months or greater, SEPD converges within -5% of the simulated reserves for all of these cases that we have explored (Cases 1.4, 1.5, 2.4 and 2.5). Arps' model with a minimum decline rate of 5% severely overestimates reserves when less than 24 months of data is available in all four short-term linear flow cases and takes 10 years or more to converge within the ±15% error range.

To summarize, this portion of the study provides evidence of the theoretical advantages the SEPD model holds over Arps' model. The SEPD model is able to converge to a more accurate solution in 8 out of 10 cases. In general, the SEPD provides more conservative forecasts than Arps' model with a minimum decline rate of 5% for the simulated cases. If Barnett Shale wells exhibited long-term linear flow, either model would suffice, but we provided evidence that some wells clearly deviate from linear flow within the first 5 years of production and suspect that many others will as well. The biggest uncertainty moving forward will be the time at which wells transition from linear flow to boundary dominated flow.

IV. SHALE GAS PRODUCTION DATA ANALYSIS

4.1 Production Data Analysis Procedure

Forecasting real world production data is not as simple as the smooth simulated cases in the previous sections. We use public data in this study so we deal with several uncertainties that oil and gas operators do not have like the number of days a well has produced in a given month or how much liquid the well is producing. Several of the uncertainties that impact decline behavior include but are not limited to the following:

- Reservoir heterogeneity
- Heterogeneous fracture properties including fracture height, half-length, conductivity, proppant strength over time, etc.
- Extent of natural fracturing and connectivity of hydraulic fractures with natural fractures
- Operational procedures including artificial lift implementation, shut-ins for offset stimulations, choke schedule, line pressure changes, etc.
- Time at which linear flow ends
- Length of time before a transition to boundary dominated flow begins
- Number of days on production in a given month
- Amount of liquids produced
- Bottomhole pressure fluctuations

In order to determine the ability of the SEPD model and Arps' model with a minimum decline of 5% to handle real world situations, we take two approaches. First we forecast groups of wells. As noted earlier, forecasting groups of wells reduces the uncertainty arising from noisy data by smoothing it out. Second, we forecast large numbers of individual wells and investigate the statistics for those wells to form conclusions about the applicability of the models and the range of uncertainty that exists for a particular model when a specific amount of data is used to forecast.

The first step in the field data analysis is to collect the data. For this study, we use Barnett Shale gas wells drilled in Denton County and Tarrant County. These counties provide a substantial number of wells drilled between the years 2004 and 2007 allowing us to perform hindcasts and determine the accuracy (to the end of history) of the models when a specified amount of history is used to forecast. The errors in the forecasted volumes for the wells are viewed in the form of histograms with wells drilled in the same year being analyzed together. When collecting the data, we apply several cutoffs in an attempt to analyze similar wells. The general cutoffs are as follows:

- Less than 1 barrel of oil per day
- Production data is available up until the most recent month
- Well is listed as directional/horizontal by DrillingInfo©
- First production occurs in a specified year (2004, 2005, 2006, or 2007)
- Well was drilled in specified county (Denton or Tarrant)

Next we plot and examine every well and observe them visually for any major discrepancies. These discrepancies include long periods (>6 months) of zeroes, a large number of erratic/anomalous months, apparent recompletions, and complete shifts in decline trends assumed to be caused by operational procedures like artificial lift installation, line pressure changes, etc. In this study, we remove wells with large discrepancies from the data set. The reasoning is they should not be forecasted from time zero – the forecast start date likely needs to be moved up to a time after the discrepancy occurred because of a shift in the decline shape. Not removing the wells would add a complexity to our analysis that we do not wish to take on since our goal is to determine how well models perform for wells with reasonable decline profiles. Moving the start date up limits the amount of data we have to compare against our forecasts. Wells with a recompletion or sudden drop and sustained change in production trend cannot and should not be forecasted from time zero with a decline curve model. If we want to account for the possibility of these situations early in the life of a well, a probabilistic approach needs to be implemented instead of a deterministic approach like we are evaluating in this study.

In the cases where a well has only a small number of zeroes or anomalously low months of production, we remove those months and move the subsequent months up. Examples of wells that were removed from the study can be found in **Appendix B**. When there are doubts of whether a well should be considered or not, the well is left in the data set. **Table 4** shows the number of wells collected from Drillinginfo.com© with the set of cutoffs listed. The second column in the tables shows the percentage of wells remaining after wells with distinct changes in decline trend (assumedly from an operational change, offset frac interference, line pressure changes, etc.) and/or a large number of anomalous points have been removed. We see both counties have a similar number of well removed from their respective 2004 groups. In the Denton County data sets, only about a quarter of the wells have to be removed with the exception of the first year. In Tarrant County, closer to one third of the initial wells in the data set are removed. The final note we have is that the highest monthly production rate for these wells is shifted to the first month.

Table 4 – Number of Barnett Shale Wells Before and % Remaining After Cull

County	2004 DrillingInfo	2005 DrillingInfo	2006 DrillingInfo	2007 DrillingInfo	2004 Remaining	2005 Remaining	2006 Remaining	2007 Remaining
Denton	75	97	113	147	64%	76%	76%	77%
Tarrant	94	155	175	395	64%	61%	66%	68%

4.2 Barnett Shale: Denton County Yearly Well Groups

Denton County, located northeast of Fort Worth, Texas, was one of the first counties in the Barnett Shale to take off with the advent of multi-stage fracturing of horizontal wells. Hence, Denton County has wells with relatively long periods of shale gas production (6+ years) that can be analyzed. **Fig. 42** shows a map with locations of 321 Denton County Barnett Shale we will analyze. Although we do not have adequate geological information or completion/operational information to determine which 2004 wells are analogs for the wells drilled in subsequent years, we use a normalized 2004 well group to come up with type curve parameters.

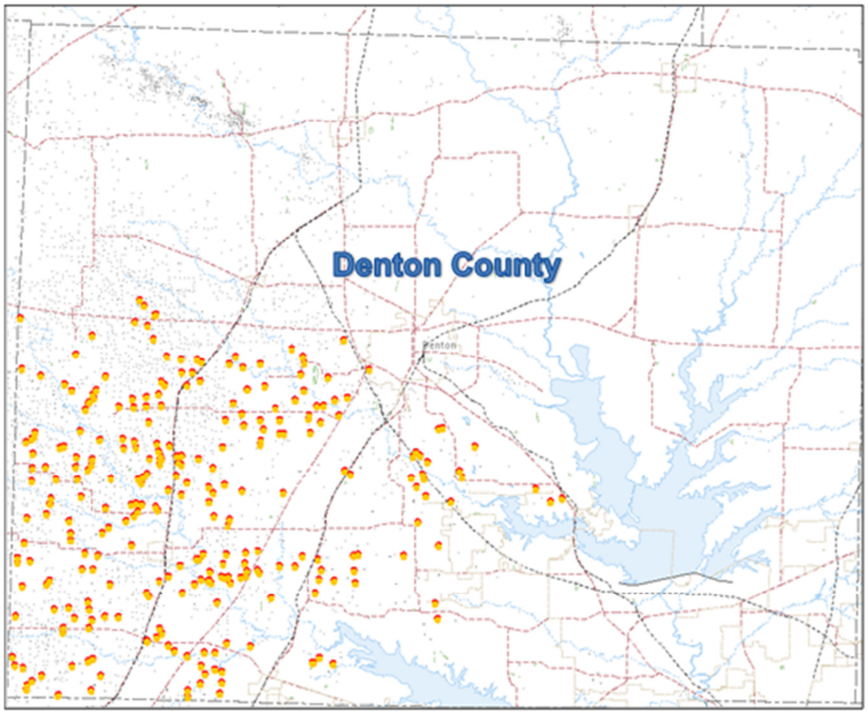

Fig. 42 – Denton County wells are concentrated in the southwest corner of the county; their proximity to one another suggests geological features may be similar.

First we look at the group forecasts, the error in volume produced between forecast start date and end of history (EOH), and how well the 2004 well group works as a type curve for the well groups drilled in subsequent years. When error is referred to from this point forward it means the percentage difference between the actual volume produced from forecast start date to end of history and the volume forecasted between forecast start date and the end of history. **Fig. 43** shows the 2004 group forecasts with the SEPD model. For group type curve forecasts in this section, we use the 36 month parameters for the 2004 group as proposed by Valko and Lee. (Valko and Lee, 2010) and make a type curve to apply to the 2005, 2006, and 2007 well groups. We recognize a group of wells from 2004 would not have 36 months of production history available to form a type curve and predict a group of wells drilled during 2005 when less than 3 years of 2004 data are available but we show this analysis to illustrate the value of forecasting groups of wells and to confirm that the 2004 well group works as an analog for 2005, 2006, 2007 well groups. From this point forward, when we forecast a production data set without a type curve, it will be noted as an "independent forecast". When we forecast production data with a type curve, we refer to this result as a "type curve forecast." Further, a type curve forecast using a 2004 well group where 24 months of data is used to solve for the type curve parameters will be referred to as "24 Month Type Curve". Similarly a type curve using parameters from a 36 month match of a 2004 well group data is called "36 Month Type Curve". Since the type curves all use 2004 well group data, we do not designate 2004.

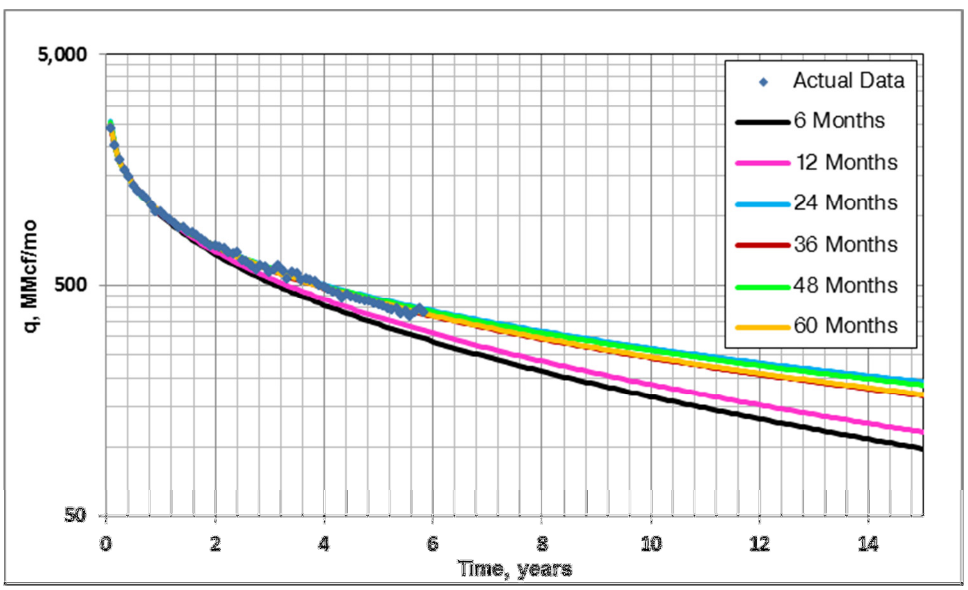

Fig. 43 – We see noise in the data even with the 2004 Denton County well groups; with 12 months of data, the SEPD model forecasts the group production to EOH (58 month forecast) with an error of 8%.

Table 5 shows the errors for the various 2004 well group forecasts and we notice the errors are all 10% or less. Also, the EURs range from 76 to 106 Bcf with the values increasing from 6 to 24 months and remaining within 5% of one another from 24 to 60 months. We are hesitant to make any definitive assertions about the EUR for the group. The most valuable observation here is the low error in group forecasts to the end of history with less than 24 months of data used to forecast.

Table 5 – 2004 Denton County Well Group Independent Forecasts

Months Used to Forecast	# Months Forecasted	Error to EOH	30 year EUR, Bcf
6	64	10%	76
12	58	8%	82
24	46	-3%	106
36	34	1%	98
48	22	-5%	104
60	10	-2%	99

Next we take a look independent forecasts for the Denton County 2005 group in **Fig. 44** and see the 6 month forecast is more conservative (closer to an exponential forecast) but every subsequent forecast looks reasonably accurate. Comparing **Fig. 45** where the 36 Month Type Curve has been applied to the 2005 well group, we notice all forecasts appear reasonable. The errors for the independent and type curve analyses of the 2005 well group are shown in **Table 6**.

Both the independent SEPD analysis and the type curve analysis provide reasonably accurate estimates to the EOH with as little as 12 months of data used to forecast. With 6 months of data, the 36 Month Type Curve already provides an estimate similar to that of the 48 month independent forecast. Assuming the wells that make up the yearly groups behave similarly to the groups, we suggest the 2004 type curve will be appropriate to forecast individual wells that make up the 2005 yearly well group.

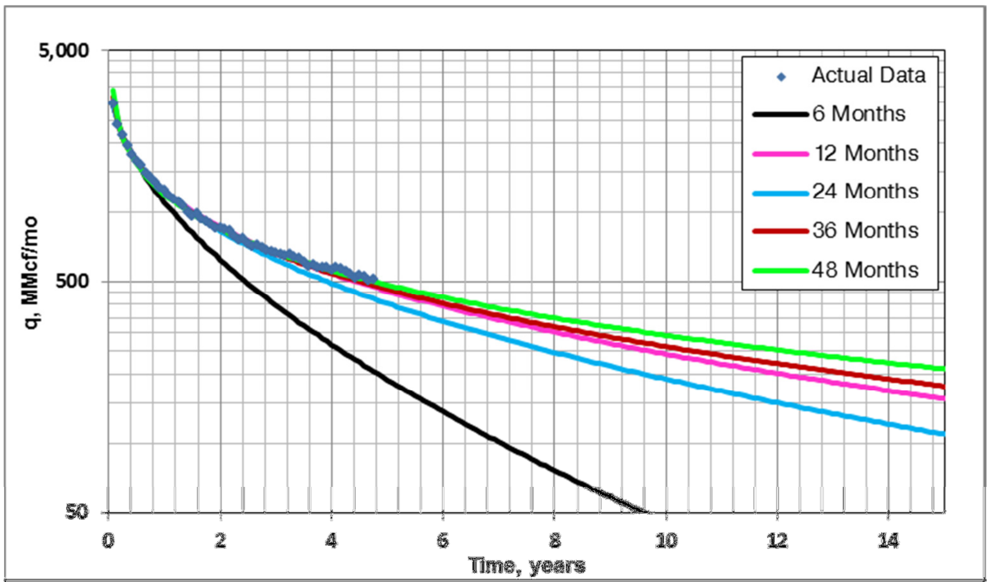

Fig. 44 – Independent forecasts for the 2005 Denton County yearly well group are reasonably accurate to the EOH (within ±15%) with the exception of the 6 month forecast.

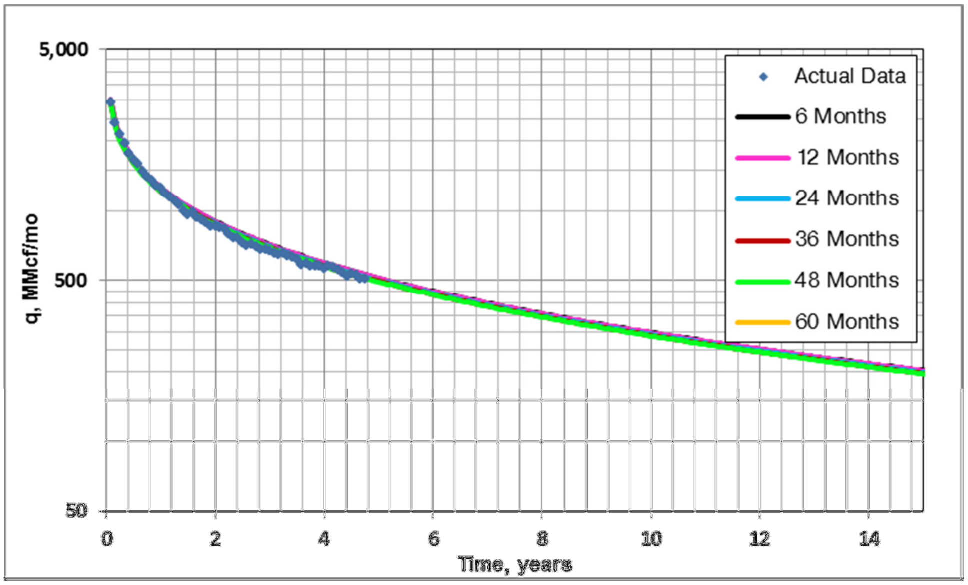

Fig. 45 – The 2004 type curve provides reliable estimates for the 2005 yearly group; -4% error in volumes produced over 51 months is achieved using only 6 months to forecast.

Table 6 – 2005 Denton County Well Group Forecast Results

Months Used to Forecast	# Months Forecasted	2005 Independent		2004 Type Curve Match	
		Error to EOH	30 year EUR, Bcf	Error to EOH	30 year EUR, Bcf
6	51	29%	51	-4%	120
12	45	0%	104	-5%	120
24	33	9%	90	-4%	118
36	21	3%	110	-2%	117
48	9	2%	120	0%	116

The 2006 well group provides further evidence grouping wells is useful in predicting future production (**Fig. 46**). **Table 7** results show the type curve provides a good estimate for volumes produced to the EOH with as little as 6 months while the independent SEPD forecast is quite conservative with 29% error in volumes produced.

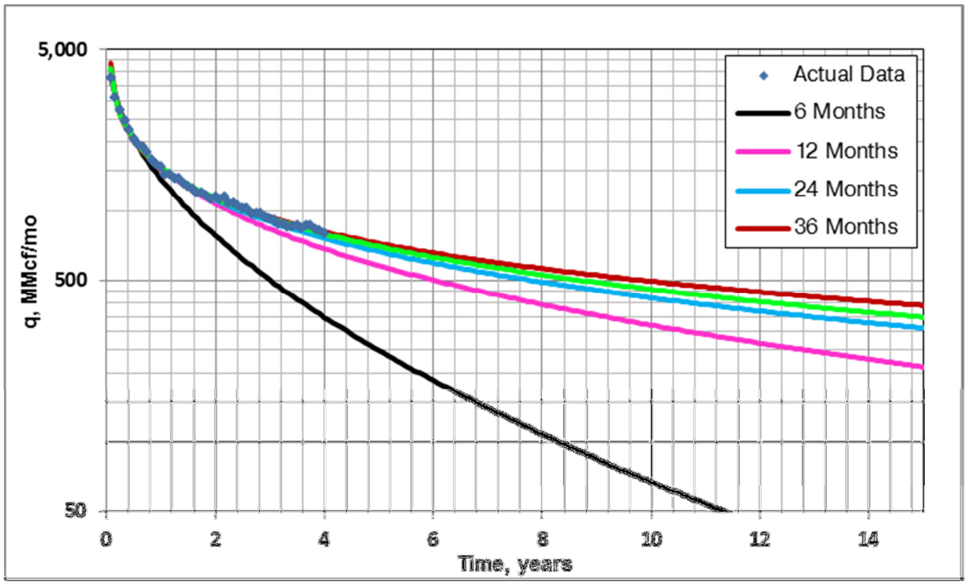

Fig. 46 – Independent forecasts for the 2006 Denton County well group are quite accurate (<10%) error with as little as 12 months used to forecast.

Although the error is reasonable for all independent SEPD model forecasts using 12 months or greater, the EUR values range from 136 Bcf with 12 months used to 191 Bcf with 36 months used. This reminds us of the uncertainty that exists moving forward. The type curve estimates the EUR at ~150 Bcf falling in the range of the independent forecasts. The 2004 well group looks like a reasonable analog for the 2006 well group and therefore the 2004 parameters warrant use as a type curve to forecast individual wells making up the 2006 well group.

Table 7 – 2006 Denton County Well Group Forecast Results

Months Used to Forecast	# Months Forecasted	2006 Independent		2004 Type Curve Match	
		Error to EOH	30 year EUR, Bcf	Error to EOH	30 year EUR, Bcf
6	41	29%	66	0%	153
12	35	7%	136	1%	151
24	23	4%	166	5%	150
36	11	-1%	191	5%	151

Concluding the Denton County yearly well group analysis, we look at the group of wells drilled in 2007 (**Fig. 47**) and see the first two forecasts are relatively conservative (>10% error) followed by 24 and 36 month forecasts that are almost identical and much more accurate. **Table 8** provides the errors to the EOH and the 30 year EUR. The EUR estimates for the 36 Month Type Curve forecasts are all around 20% less than the 24 and 36 month independent EUR estimates. Looking at production history, we see near the EOH there are several months of increased or flat production. While this has minimal impact on the type curve forecasts (it alters the q_o slightly), the independent forecasts honor what appears to be an artifact (likely to be caused by a field wide change in line pressure) since the production decline tends back towards the decline profile of the type curve (**Fig. 48**). Combining this fact with the 18% and 12% error in the first two independent forecasts provides evidence that a type curve should be used when 12 months or less production history is available to forecast. It also leads us to the idea that a type curve can serve as a quality check for EUR estimates. We suggest the reserves estimator always visually inspects the type curve rate-time match before putting confidence in the EUR estimates.

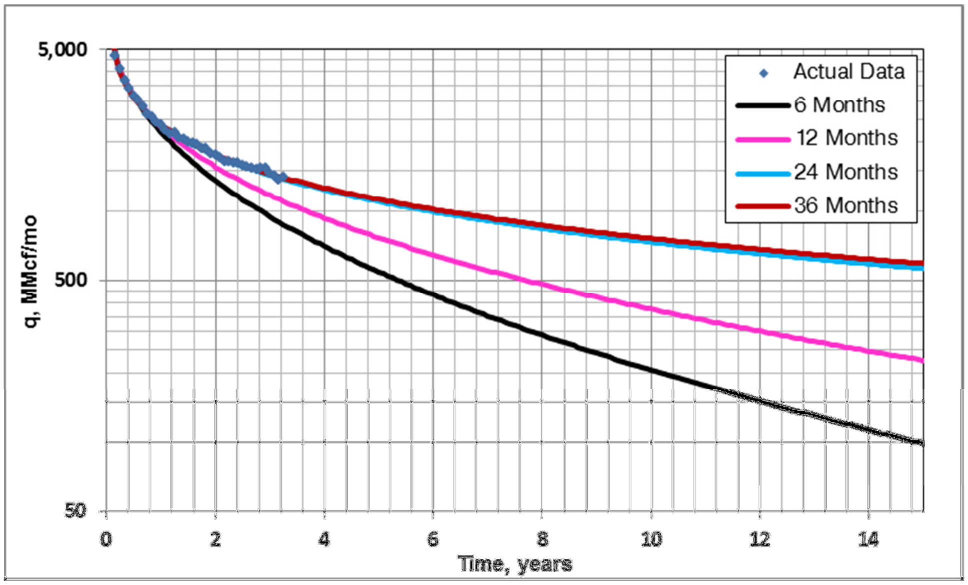

Fig. 47 – The 2007 well group needs 24 months of data to provide a forecast with 10% error or less.

Table 8 – 2007 Denton County Well Group Forecast Results

Months Used to Forecast	# Months Forecasted	2007 Independent		2004 Type Curve Match	
		Error to EOH	30 year EUR, Bcf	Error to EOH	30 year EUR, Bcf
6	33	18%	128	0%	233
12	27	12%	175	2%	230
24	15	1%	283	4%	230
36	3	-2%	292	4%	232

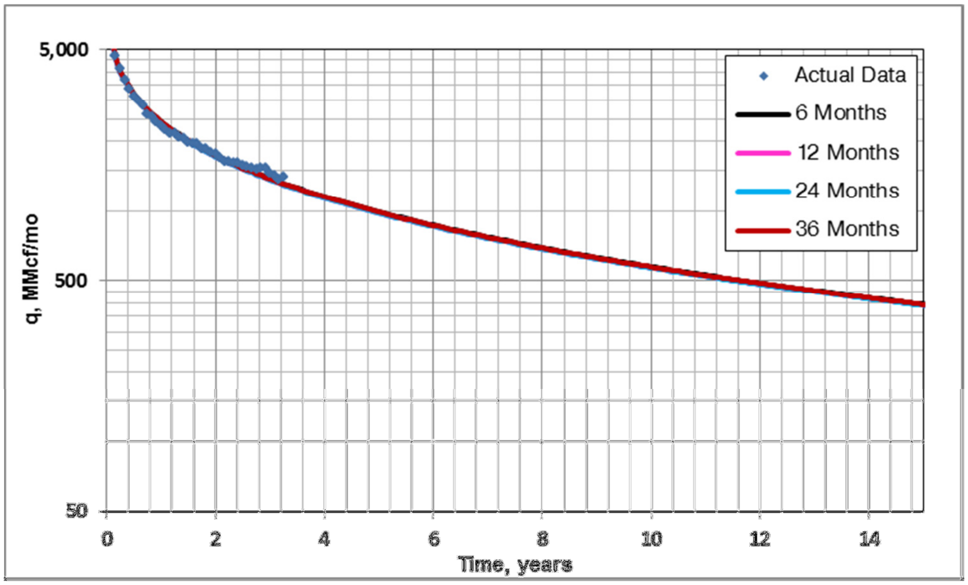

Fig. 48 – 36 Month Type Curve forecasts of the 2007 well group are not thrown off by the discrepancy in the data shortly before the 3 year mark; the production appears to be headed back to the decline behavior forecasted by the type curve.

4.3 Barnett Shale: 2004 Denton County Individual Wells

In the following sections, we demonstrate the ability of the SEPD model and Arps' model with a minimum decline rate of 5% to forecast individual shale gas wells. We start by performing multiple forecasts on a given well using varying amounts of production history (6 months, 12 months, 24 months, etc.). For each well, we require at least 12 months of unmatched history for the error to be considered in the statistics. We are most interested in quantifying the error between the forecasted volume and the actual produced volumes that are observed. We will comment on EUR trends but our focus is on how accurately the models fit the production data that we know to be true.

First we look at 48 individual Denton County Barnett Shale gas wells drilled during the year 2004. Since 2004 is the first year that we analyze, a type curve does not exist to apply to these wells. In this section and future sections we will present several histograms. The histograms are interpreted as follows: all errors below and up to -50% are shown as the frequency in line with -50%, all errors between -10% and 0% are shown as the frequency in line with 0%, all errors between 10% and 20% are shown as the frequency in line with 20%, and so on and so forth. Making the assumption that error should be distributed normally, we expect the mean error to be in line with either 10% or 0% error. For reserves reporting purposes, we would like it to center on 10% since we prefer more wells to be in the positive range (underestimate reserves) rather than the negative range (overestimate reserves)

With only 6 months of production history available to forecast, the SEPD model gives very conservative forecasts (**Fig. 49**); 71% of wells have positive errors and 38% of wells have errors above 50%. We do not see normal distributions forming until 24 months or greater is used to forecast. The mean of the semi-normal distributions is tending toward the 10% bin (slightly underestimating).

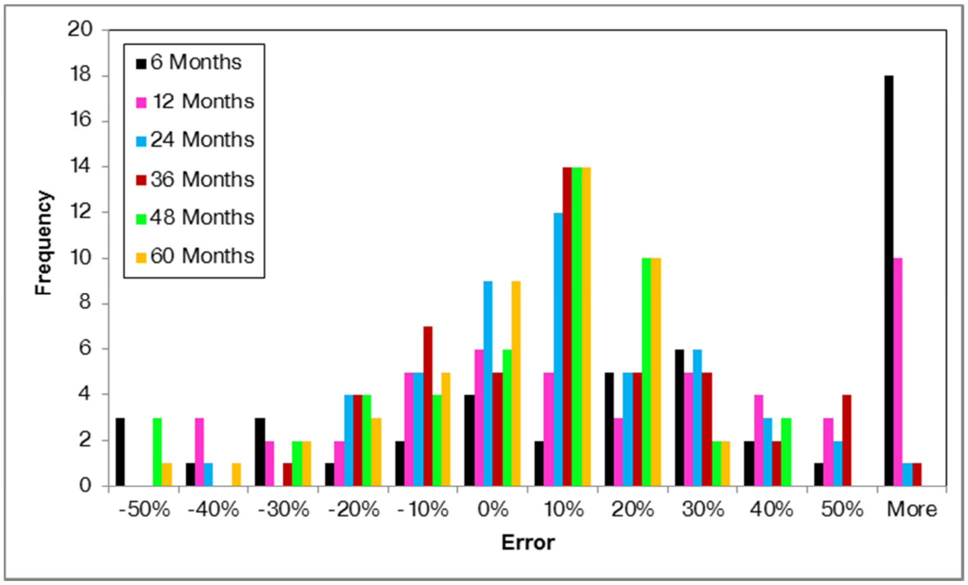

Fig. 49 – SEPD provides a large percentage of extremely conservative future volumes estimates for 2004 Denton County wells with only 6 months available to forecast; forecasts are generally conservative for all amounts of data used.

Arps' model with a minimum decline rate of 5% provides slightly more accurate errors than the SEPD model when 6 month of data is used but also has a large number of conservative forecasts (**Fig. 50**). The error distributions are not consistently conservative like the SEPD model with the 24 and 48 months distributions being skewed left. We see when 60 months of data is used to forecast, the error distribution has a mean tending towards the 10% bin.

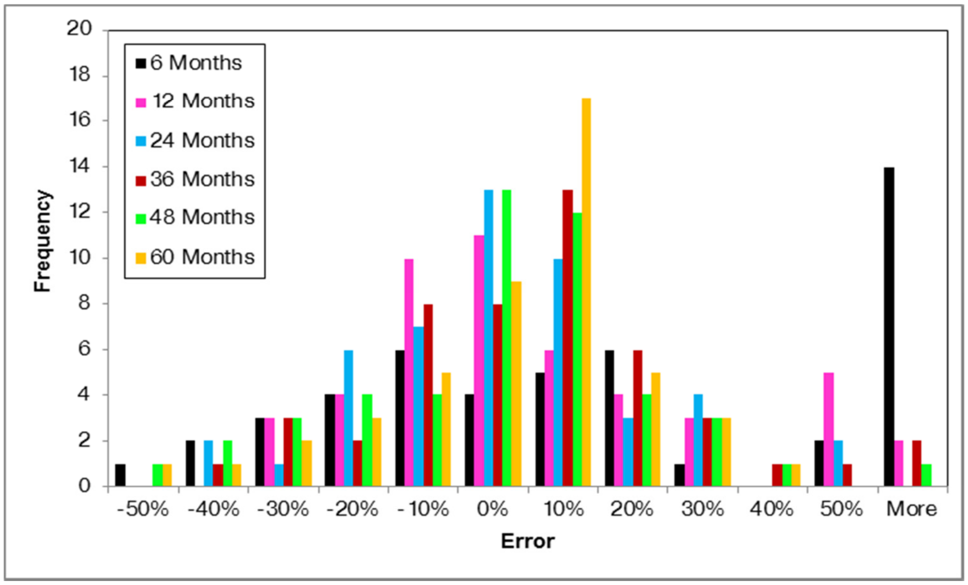

Fig. 50 – Errors in forecasted volumes of 2004 Denton County wells do not have a recognizable distribution when using the Arps' minimum decline rate method with 6 months of data to forecast; error distributions tend towards normal with 12 months of data or greater used to forecast.

Table 9 provides the results for all independent SEPD model forecasts of the 2004 Denton County wells. The numbers in green represent scenarios where the independent SEPD model yields more favorable results Arps' model with a minimum decline rate of 5%. **Table 10** provides the results for the Arps' model with a minimum decline rate of 5%. Similarly, results shown in green are scenarios where Arps' model with a minimum decline rate gives more favorable results than the independent SEPD model. Throughout this study, we focus on the percentage of wells in the -20% to 20% error bin and the percentage of wells that give conservative estimates (positive errors). The table headings are explained as follows:

Wells : # of wells with 12 months or greater to compare forecast against

< -50% : percentage of forecasts with less than -50% error (overestimating)

(-) : percentage of forecasts with negative error (overestimating)

-20%<x<20% : percentage of forecasts with error between -20% and 20%

-50%<x<50% : percentage of forecasts with error between -50% and 50%

(+) : percentage of forecasts with positive error (underestimating)

> 50% : percentage of forecasts with greater than 50% error (underestimating)

Table 9 – Error of 2004 Denton County Wells Using Independent SEPD Model

Months Used to Forecast	# Wells	SEPD Independent Error					
		<-50%	(-)	-20%<x<20%	-50%<x<50%	(+)	>50%
6	48	6%	29%	27%	56%	71%	38%
12	48	0%	38%	40%	79%	63%	21%
24	48	0%	40%	65%	98%	60%	2%
36	48	0%	35%	65%	98%	65%	2%
48	48	6%	40%	71%	94%	60%	0%
60	47	2%	45%	81%	98%	55%	0%

Table 10 – Error of 2004 Denton County Wells Using Arps with a Minimum Decline Rate of 5%

Months Used to Forecast	# Wells	Arps Minimum Decline of 5% Error					
		<-50%	(-)	-20%<x<20%	-50%<x<50%	(+)	>50%
6	48	2%	42%	44%	69%	58%	29%
12	48	0%	58%	65%	96%	42%	4%
24	48	0%	60%	69%	100%	40%	0%
36	48	0%	46%	73%	96%	54%	4%
48	48	2%	56%	69%	96%	44%	2%
60	47	2%	45%	77%	98%	55%	0%

Two observations in Table 10 stick out. First, Arps' model with a minimum decline rate provides slightly more accurate results when 12 through 36 months of history is used but the independent SEPD model starts to slightly outperform Arps' when 48 or 60 months of data is available. Second, the errors from forecasts using Arps' minimum decline rate are not as conservative as the SEPD model forecasts. With all other things being approximately equal, we prefer to have a model that errs on the side of caution.

To investigate the EUR estimates, we look at the difference between the 30 year EUR for the SEPD model and Arps' model with a 5% minimum decline rate. **Fig. 51** shows that as more data becomes available to forecast, the models provide EUR estimates that are closer and closer in value. Similar to the error histograms, the 0.00E+00 bin shows the number of estimates that are between -3.00E+05 and 0.00E+00. As with the errors, the Arps' model EUR estimates are slightly more optimistic than the SEPD EUR estimates.

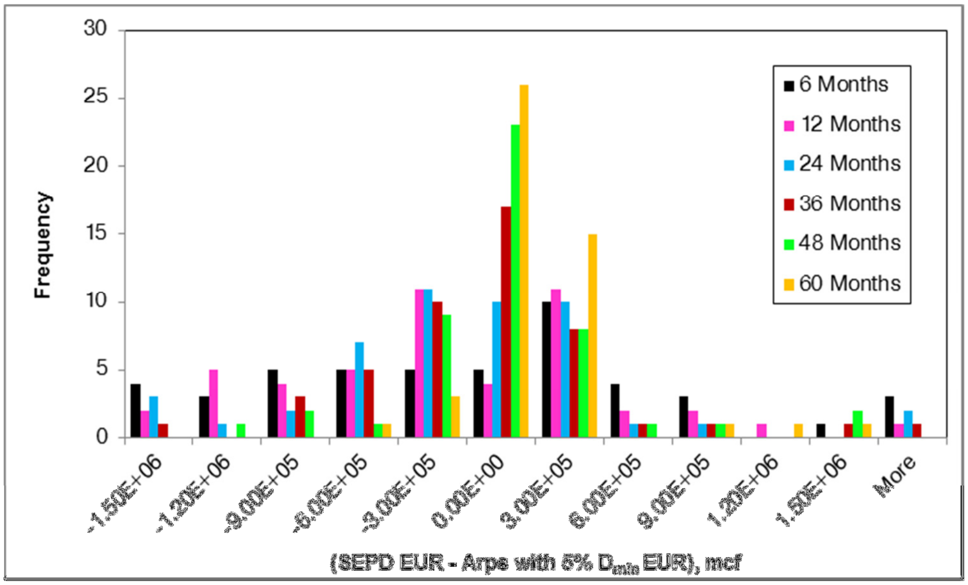

Fig. 51 – EUR estimates for 2004 Denton County wells using Arps' model with a minimum decline rate of 5% are consistently higher than SEPD EUR estimates.

4.4 **Barnett Shale: 2005 Denton County Individual Wells**

Next we look at 74 Denton County wells drilled and completed during the year 2005. Here we apply 2004 Denton County Type Curves to see if they provide more accurate future volume estimates when limited data is available. The following four type curves are applied: 24 Month Type Curve, 36 Month Type Curve, 48 Month Type Curve, and 60 Month Type Curve. This will also provide insight as to how much data we need to develop a type curve.

The 2005 individual well forecasts results using 6 months of data with the independent SEPD model (**Fig. 52**) and Arps' model with a minimum decline rate (**Fig. 53**) yield similar results to the 2004 individual well forecasts using 6 months of data. We note a large number of forecasts for both models are at or near exponential decline

(>50% error). The production data points for these wells do not provide much curvature within the first 6 months of production so the models match the apparent exponential decline that they see. In this case, it appears that Arps' with a minimum decline rate recognizes curvature earlier than the SEPD model since there are fewer extreme outliers when 24 months of data or less is used to forecast. The error distribution for Arps' model with a minimum decline rate looks more favorable than the error distribution for the SEPD model when 12 months of data is used to forecast. When 36 months or greater is used to forecast, Arps' model with a minimum decline rate gives error distributions that are tending towards normal with a mean that is slightly negative (0% bin – overestimating).

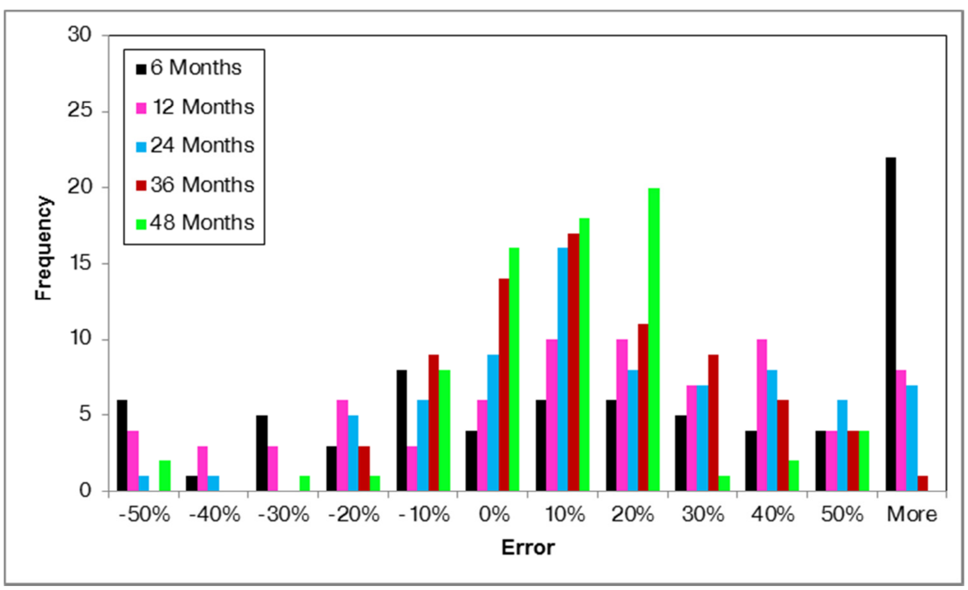

Fig. 52 – Independent SEPD forecasts of 2005 Denton County wells exhibit error distributions that are semi-normal when 24 months of data or greater is used; 36 month and 48 month forecasts have relatively conservative errors.

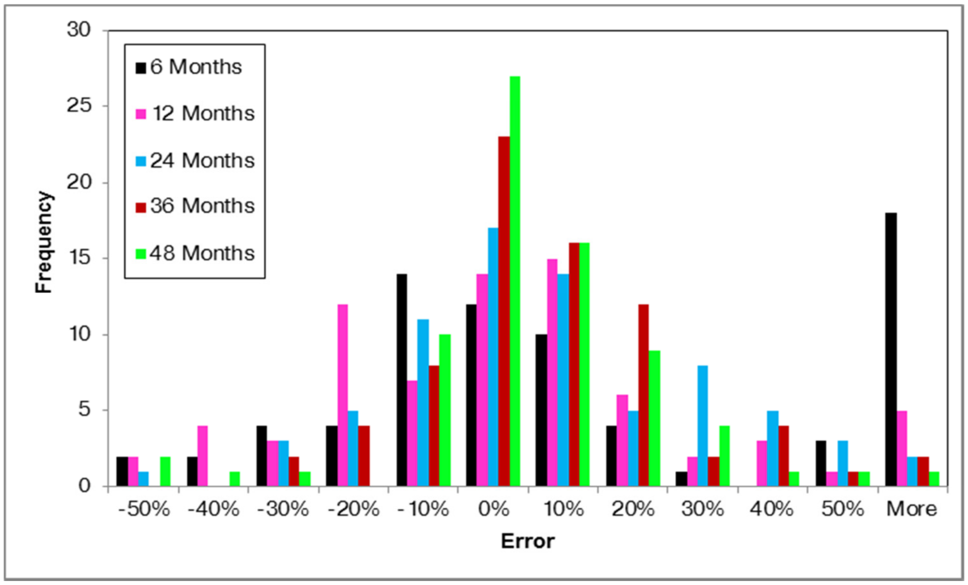

Fig. 53 – Forecasts for Arps' model with a minimum decline rate of 5% slightly overestimate produced volumes when 36 months or greater is used to forecast; with 24 more months or greater used to forecast, error distributions are semi-normal.

In **Fig. 54** and **Fig. 55**, the 24 Month Type Curve and 36 Month Type Curve error distributions are displayed. Both are very similar in shape to a normal distribution with as little as 6 months used to forecast. The number of extreme outliers with 6 months of data used to forecast is much lower in comparison to the independent SEPD model and Arps' model with a minimum decline rate of 5%. When 12 months or more is used to forecast, error distributions tend towards normal with a mean in the 0% bin.

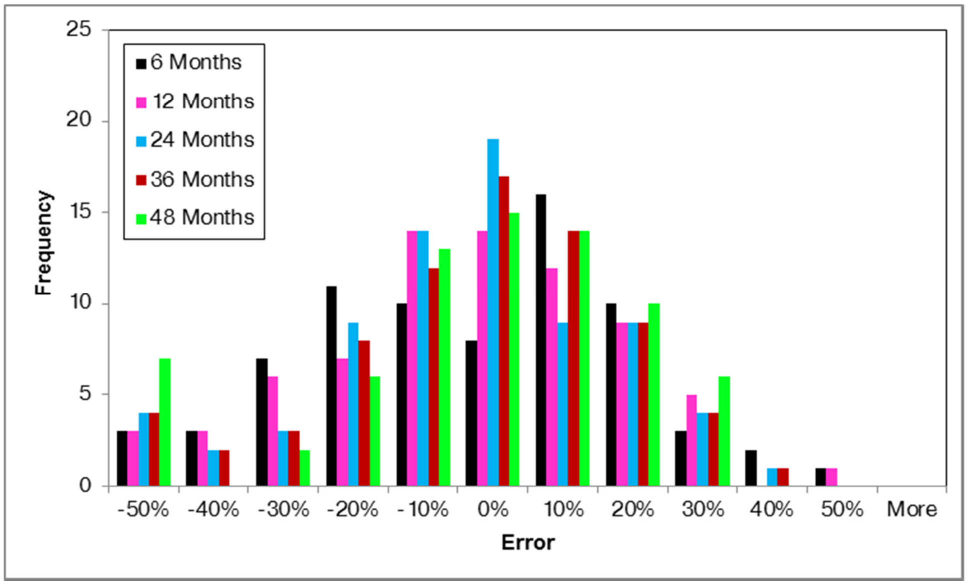

Fig. 54 – 24 Month Type Curve forecasts of 2005 Denton County wells using 6 months of data provide a more favorable distribution shape than Arps' with a minimum decline or the independent SEPD model; error distributions tend to be further left than the independent SEPD model distributions.

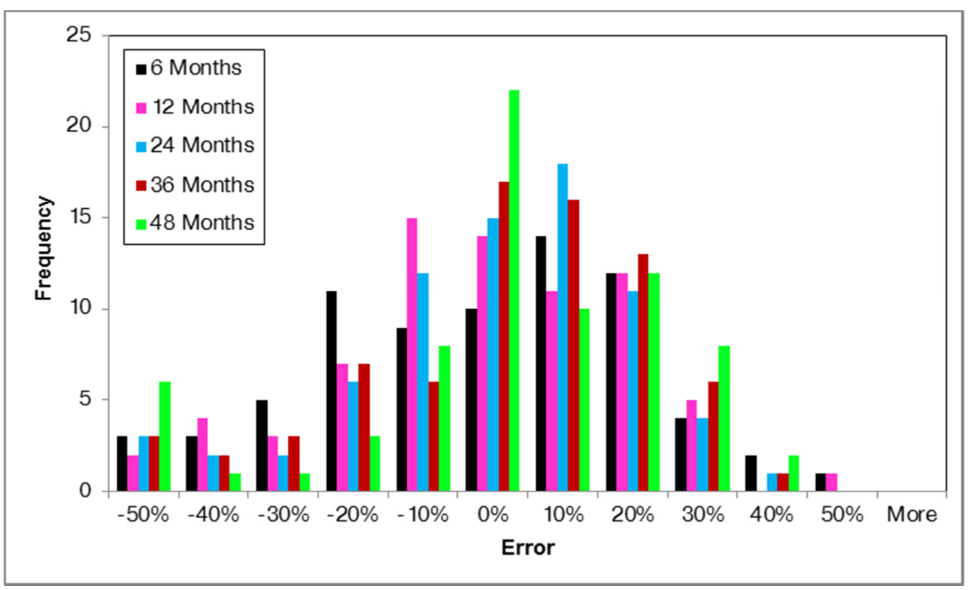

Fig. 55 – 36 Month Type Curve forecasts of 2005 Denton County wells provide similar error distributions to the 24 Month Type Curve; the 6-24 month forecasts are slightly more accurate.

Further investigating which method gives the most accurate results, we look at the tabulated statistics in the following tables: **Table 11** (Independent SEPD), **Table 12** (Arps' with minimum decline rate of 5%), **Table 13** (24 Month Type Curve), **Table 14** (36 Month Type Curve), **Table 15 (**48 Month Type Curve), and **Table 16** (60 Month Type Curve). The tables provide evidence of the following:

- SEPD provides the most conservative estimates regardless of the amount of data being used.
- The 36 Month Type Curve provides the largest number of forecasts with errors between -20% and 20% when 24 months or less is used to forecast; the errors are skewed slightly left.
- There is not much difference in the various type curve results which is to be expected since the type curves all have similar parameters. The 36 Month Type curves provides the best estimates when 24 months of data or less is used to forecast From this point forward, we will only consider the 36 Month Type Curve for discussion purposes.
- SEPD has the most wells with error between -20% and 20% when 48 or 60 months of data is used; the errors are skewed further right than the other methods.
- EUR estimates for the independent SEPD model and Arps' with a minimum decline rate converge to similar values as more data becomes available.

Table 11 - Error of 2005 Denton County Wells Using Independent SEPD Model

Months Used to Forecast	# Wells	SEPD Independent Error					
		<-50%	(-)	-20%<x<20%	-50%<x<50%	(+)	>50%
6	74	8%	36%	32%	62%	64%	30%
12	74	5%	34%	39%	84%	66%	11%
24	74	1%	30%	53%	89%	70%	9%
36	74	0%	35%	69%	99%	65%	0%
48	73	3%	38%	85%	97%	62%	0%
60	36	0%	42%	83%	97%	58%	3%

Table 12 - Error of 2005 Denton County Wells Using Arps with a Minimum Decline Rate of 5%

Months Used to Forecast	# Wells	Arps Minimum Decline of 5% Error					
		<-50%	(-)	-20%<x<20%	-50%<x<50%	(+)	>50%
6	74	3%	51%	54%	73%	49%	24%
12	74	3%	57%	57%	91%	43%	7%
24	74	1%	50%	64%	96%	50%	3%
36	74	0%	50%	80%	97%	50%	0%
48	73	3%	56%	85%	96%	44%	1%
60	36	0%	50%	78%	97%	50%	3%

Table 13 - Error of 2005 Denton County Wells Using 24 Month Type Curve

Months Used to Forecast	# Wells	SEPD 2004 24 Month Type Curve					
		<-50%	(-)	-20%<x<20%	-50%<x<50%	(+)	>50%
6	74	4%	57%	59%	96%	43%	0%
12	74	4%	64%	66%	96%	36%	0%
24	74	5%	69%	69%	95%	31%	0%
36	74	5%	62%	70%	95%	38%	5%
48	73	10%	59%	71%	90%	41%	0%
60	36	8%	53%	69%	92%	47%	0%

Table 14 - Error of 2005 Denton County Wells Using 36 Month Type Curve

Months Used to Forecast	# Wells	SEPD 2004 36 Month Type Curve					
		<-50%	(-)	-20%<x<20%	-50%<x<50%	(+)	>50%
6	74	4%	55%	61%	96%	45%	0%
12	74	3%	61%	70%	97%	39%	0%
24	74	4%	54%	76%	96%	46%	0%
36	74	4%	51%	70%	96%	49%	4%
48	73	8%	56%	71%	92%	44%	0%
60	36	8%	47%	72%	92%	53%	0%

Table 15 - Error of 2005 Denton County Wells Using 48 Month Type Curve

Months Used to Forecast	# Wells	SEPD 2004 48 Month Type Curve					
		<-50%	(-)	-20%<x<20%	-50%<x<50%	(+)	>50%
6	74	4%	57%	58%	96%	43%	0%
12	74	4%	64%	66%	96%	36%	0%
24	74	5%	64%	72%	95%	36%	0%
36	74	5%	59%	68%	95%	41%	5%
48	73	10%	58%	74%	90%	42%	0%
60	36	8%	53%	72%	92%	47%	0%

Table 16 - Error of 2005 Denton County Wells Using 60 Month Type Curve

Months Used to Forecast	# Wells	SEPD 2004 60 Month Type Curve					
		<-50%	(-)	-20%<x<20%	-50%<x<50%	(+)	>50%
6	74	4%	57%	58%	96%	43%	0%
12	74	3%	61%	69%	97%	39%	0%
24	74	4%	58%	76%	96%	42%	0%
36	74	4%	54%	69%	96%	46%	4%
48	73	8%	58%	73%	92%	42%	0%
60	36	8%	50%	72%	92%	50%	0%

Taking a look at the difference in EUR estimates (**Fig. 56**), we note both models tend towards similar EUR estimates as more data becomes available to forecast. Similar to the errors, the EUR estimates from Arps' model with a minimum decline rate of 5% tend to be more optimistic than EUR estimates from the independent SEPD model. 60 month EUR estimates are remarkably similar as evidenced by a tight distribution centered on the 0.00E+00 bin.

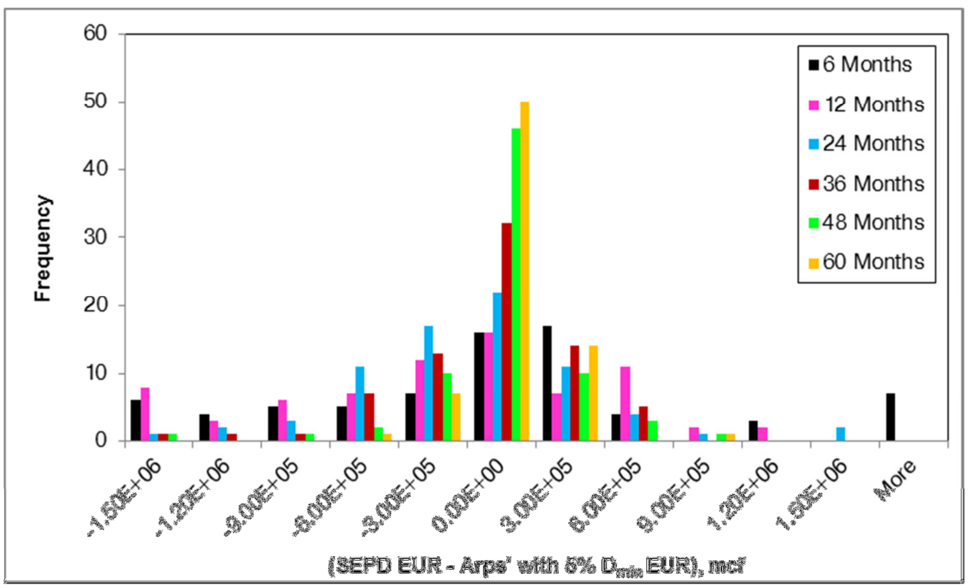

Fig. 56 – 2005 Denton County individual well EUR estimates for the two models converge towards similar values as more data becomes available.

4.5 **Barnett Shale: 2006 Denton County Individual Wells**

Continuing our analysis, we move on to 86 Denton County wells drilled and completed during 2006. As has been the case for several of the simulations and field data up to this point, the SEPD model still has a large number of conservative forecasts when

12 months or less is used to forecast (**Fig. 57**). On the other hand, Arps' model with a minimum decline rate of 5% has relatively few conservative forecasts when 12 months of data is used (**Fig. 58**) and is already tending towards a normal distribution. The 36 Month Type Curve results (**Fig. 59**) using 12 months of data are very similar to Arps' model with a minimum decline rate and have an error distribution that is also tending towards normal. The type curve error distribution is clearly more favorable than that of the independent SEPD model or Arps' with a minimum decline rate when 6 months of data is used. When 12 months of data is used, the type curve provides an error distribution that is more favorable than the independent SEPD model, but it is not clear for Arps' model with a minimum decline rate.

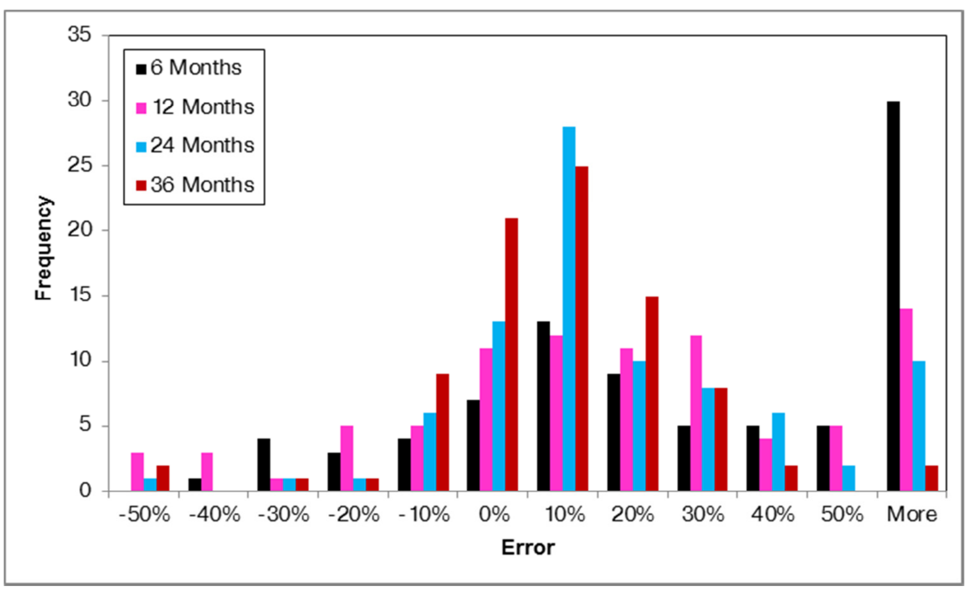

Fig. 57 – Independent SEPD forecasts of 2006 Denton County wells using 12 months of data exhibit an error distribution that is tending towards normal; the highest frequency bin is still the most conservative, "More"; forecasts are conservative for all amounts of data used to forecast.

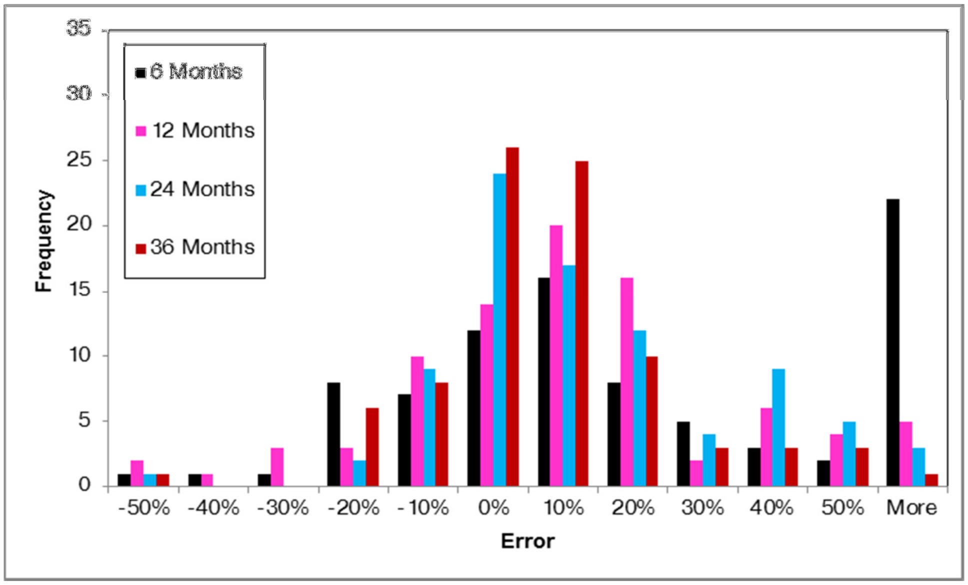

Fig. 58 – Errors from Arps' model with a minimum decline rate of 5% forecasts of 2006 Denton County wells with 12 months of data already show resemblance of a normal distribution; when 24 or 36 months is used, the mean is tending toward the 0% bin (slightly overestimating).

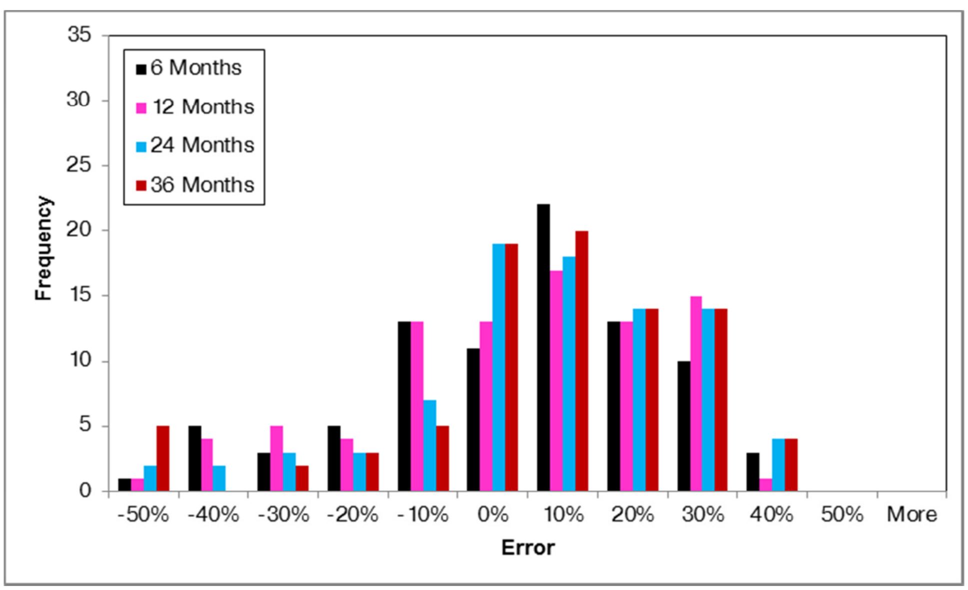

Fig. 59 –Errors for 36 Month Type Curve forecasts of 2006 Denton County wells yield similar error distributions regardless of the amount of data used; forecasts with 6 months of data are clearly more accurate than the two other models.

The detailed tabulated results are presented in **Table 17** (independent SEPD), **Table 18** (Arps with minimum decline rate of 5%) and **Table 19** (36 Month Type Curve). The independent SEPD model provides the most conservative forecasts overall with the percentage of positive errors decreasing over time. For this data set, the 36 Month Type Curve is the most accurate method only for the forecasts with 6 months of data. For 12 months and 24 months, Arps with a minimum decline of 5% gives the most accurate results. As we have seen in prior cases, the independent SEPD becomes as good or better when there are 36 or 48 months of data available to forecast.

Table 17 - Error of 2006 Denton County Wells Using Independent SEPD model

Months Used to Forecast	# Wells	SEPD Independent Error					
		<-50%	(-)	-20%<x<20%	-50%<x<50%	(+)	>50%
6	86	0%	22%	38%	65%	78%	35%
12	86	3%	33%	45%	80%	67%	16%
24	86	1%	26%	66%	87%	74%	12%
36	86	2%	40%	81%	95%	60%	2%
48	43	0%	40%	84%	100%	60%	0%

Table 18 - Error of 2006 Denton County Wells Using Arps with a Minimum Decline Rate of 5%

Months Used to Forecast	# Wells	Arps Minimum Decline of 5% Error					
		<-50%	(-)	-20%<x<20%	-50%<x<50%	(+)	>50%
6	86	1%	35%	50%	73%	65%	26%
12	86	2%	38%	70%	92%	62%	6%
24	86	1%	42%	72%	95%	58%	3%
36	86	1%	48%	80%	98%	52%	1%
48	43	0%	40%	81%	98%	60%	2%

Table 19 - Error of 2006 Denton County Wells Using 36 Month Type Curve

Months Used to Forecast	# Wells	SEPD 2004 36 Month Type Curve					
		<-50%	(-)	-20%<x<20%	-50%<x<50%	(+)	>50%
6	86	1%	44%	69%	99%	56%	0%
12	86	1%	47%	65%	99%	53%	0%
24	86	2%	42%	67%	98%	58%	0%
36	86	6%	40%	67%	94%	60%	6%
48	43	5%	30%	72%	95%	70%	0%

The differences in EUR estimates for the 2006 wells (**Fig. 60**) are very similar results to differences of the 2005 wells. The independent SEPD model and Arps' model with a minimum decline rate of 5% converge towards similar EUR estimates as more data becomes available to forecast. The Arps' model estimates are more optimistic with a mean centering on 0.00E+00 when 24 months or greater is used. The distributions are also skewed left indicating Arps' model estimates are more optimistic for any amount of data used to forecast.

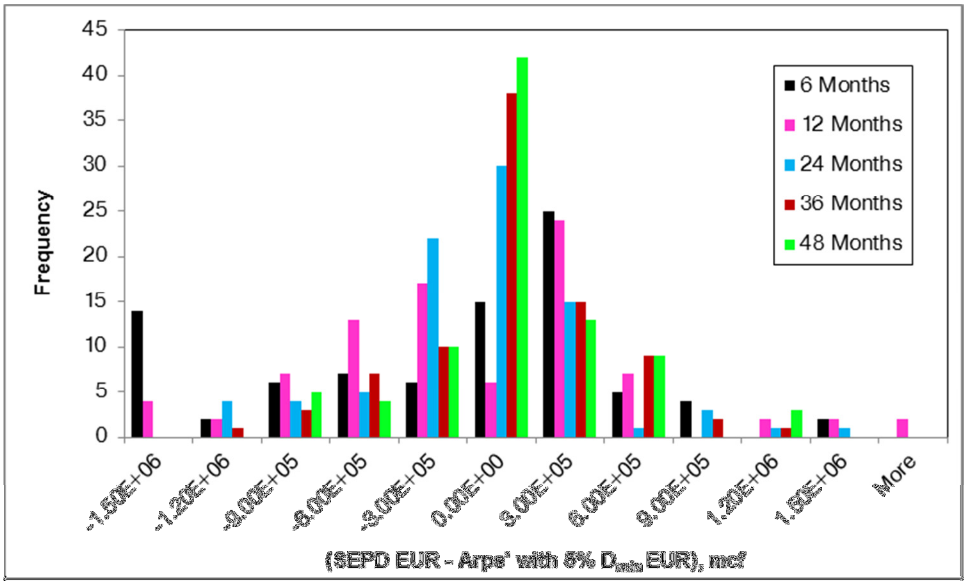

Fig. 60 – For 2006 Denton County wells, the difference in independent SEPD EUR estimates and Arps' EUR estimates provides evidence the models are converging towards similar values as more data becomes available.

The following observations summarize the 2006 Denton County individual wells statistics:

- The independent SEPD model provides the most conservative estimates regardless of the amount of data used to forecast. Errors are at least 60% positive for all cases.
- The type curve provides the most accurate forecasts when 6 months of data are available to forecast with 69% of wells in the -20 to 20% range.
- Arps' model with a minimum decline rate of 5% provides more accurate forecasts (by a small margin over the type curve) when 12 or 24 months of data is used.

- The independent SEPD model provides the most accurate forecasts (by a small margin over Arp's model with a minimum decline rate) when 36 or 48 months of data is used to forecast.
- EUR estimates for Arps' model with a minimum decline rate are more optimistic than independent SEPD EUR estimates.

4.6 **Barnett Shale: 2007 Denton County Individual Wells**

We conclude the Denton County study with the 113 wells drilled and completed during 2007. The independent SEPD error histogram (**Fig. 61**) appears to be exactly normal when 24 months of data is used with the error histogram for Arps' model with a minimum decline rate of 5% (**Fig. 62**) coming very close as well. When 12 months of data is used to forecast, normal distributions are already being formed by the errors for both models. We note that for the 2007 wells there is less data available to forecast than previous examples (2004, 2005, and 2006). Therefore, we are not surprised to see normal distributions earlier. Although Arps' model with a minimum decline rate and the independent SEPD model provide errors that follow a normal distribution when 12 months of data is used, the 36 Month Type Curve forecasts yields an error distribution that is obviously more accurate (**Fig. 63**). For the 2007 wells, the independent SEPD has the highest percentage of positive errors.

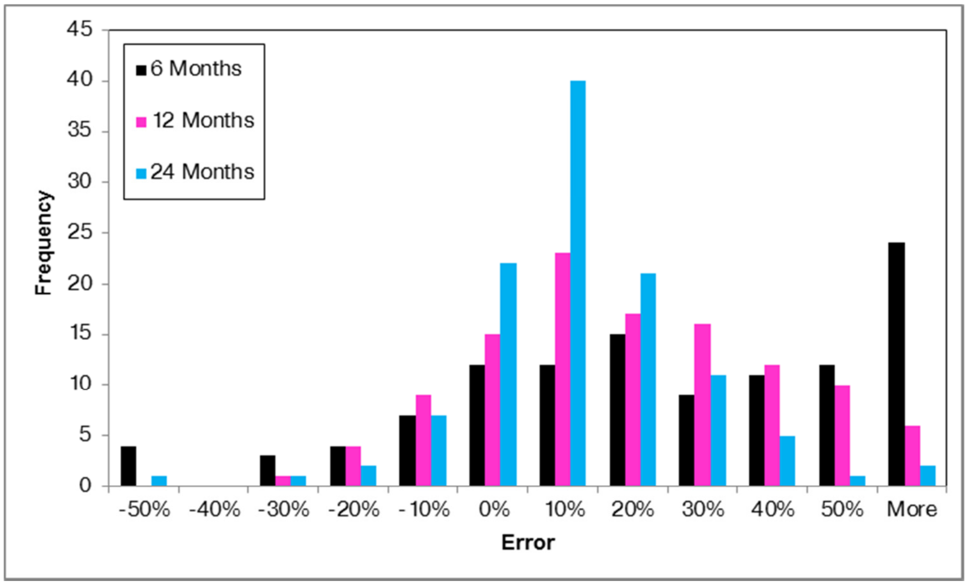

Fig. 61 – Independent SEPD forecasts of 2007 Denton County wells using 12 months of data have an error distribution that is tending toward normal and skewed right.

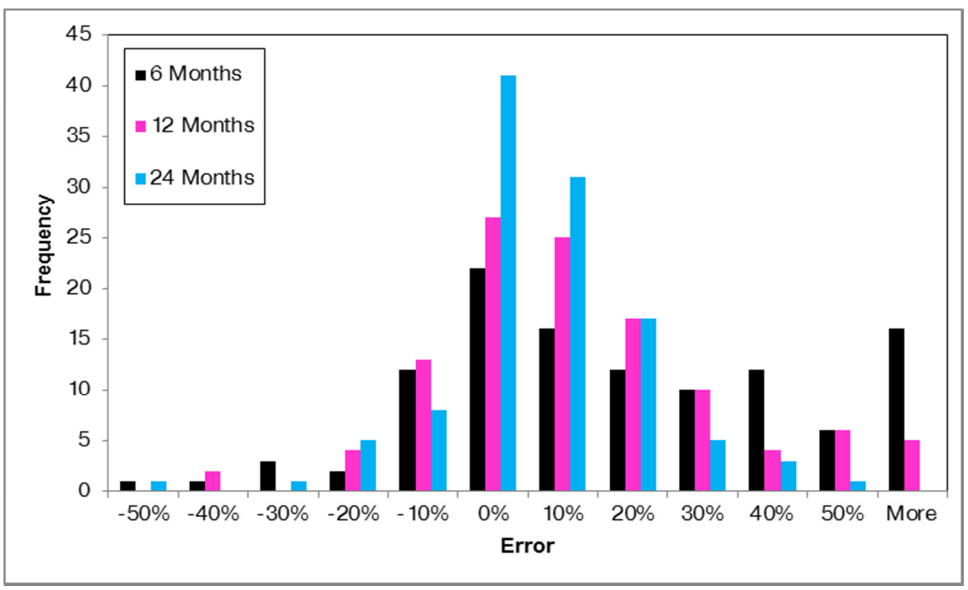

Fig. 62 – Forecasts using Arps' model with a minimum decline rate of 5% are more accurate than the independent SEPD model when 6 months of data is available; when 24 months is available to forecast, the mean is tending towards the 0% bin (slightly overestimate).

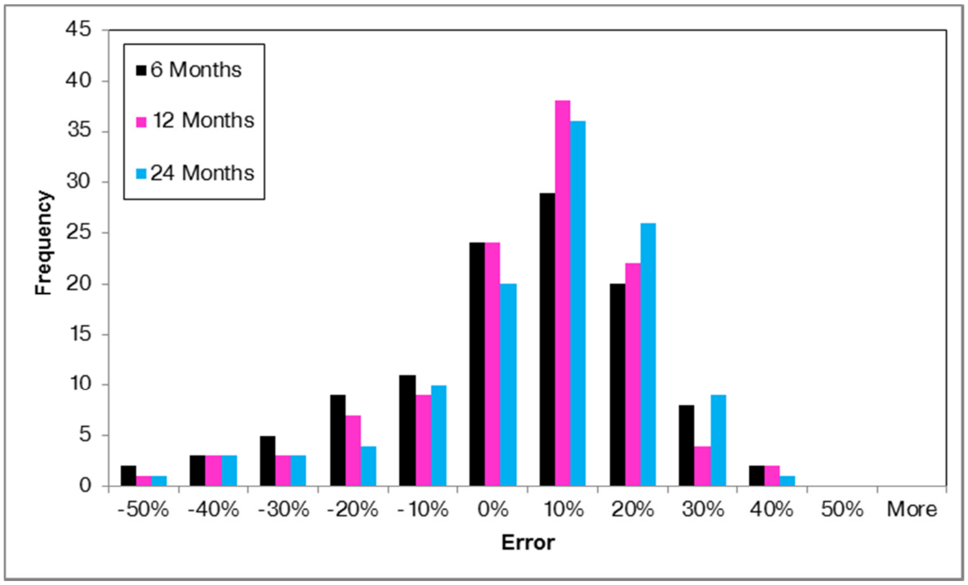

Fig. 63 –Errors for 36 Month Type Curve forecasts of 2007 Denton County wells appear to form a semi-normal distribution with 82% of wells falling between -20% and 20% when 12 months of data is used to forecast.

The 36 Month Type Curve provides reasonably accurate forecasts for all amounts of data used; the error distributions are shifting right over time. Examining the statistics in **Table 20, Table 21, and Table 22**, we note the following:

- The type curve is most accurate for forecasts using 6 or 12 months of data and provides a very comparable error distribution when 24 months of data is used.
- The independent SEPD model provides more conservative estimates than Arps' model with a minimum decline rate for all scenarios.

Table 20 - Error of 2007 Denton County Wells Using Independent SEPD

Months Used to Forecast	# Wells	SEPD Independent Error					
		<-50%	(-)	-20%<x<20%	-50%<x<50%	(+)	>50%
6	113	4%	27%	41%	75%	73%	21%
12	113	0%	26%	57%	95%	74%	5%
24	113	1%	29%	80%	97%	71%	2%
36	52	0%	52%	90%	100%	48%	0%

Table 21 - Error of 2007 Denton County Wells Using Arps with a Minimum Decline Rate of 5%

Months Used to Forecast	# Wells	Arps Minimum Decline of 5% Error					
		<-50%	(-)	-20%<x<20%	-50%<x<50%	(+)	>50%
6	113	1%	36%	55%	85%	64%	14%
12	113	0%	41%	73%	96%	59%	4%
24	113	1%	50%	86%	99%	50%	0%
36	52	0%	58%	96%	100%	42%	0%

Table 22 - Error of 2007 Denton County Wells Using 36 Month Type Curve

Months Used to Forecast	# Wells	SEPD 2004 36 Month Type Curve					
		<-50%	(-)	-20%<x<20%	-50%<x<50%	(+)	>50%
6	130	2%	50%	72%	98%	50%	0%
12	130	1%	43%	82%	99%	57%	0%
24	130	1%	38%	82%	99%	62%	0%
36	52	0%	37%	87%	100%	63%	0%

As with the previous 3 data sets, the EUR estimates for the independent SEPD model and Arps' model with a minimum decline rate of 5% are converging towards similar values as more data becomes available (**Fig. 64**). The distribution is skewed left with a mean on 0.00E+00 indicating independent SEPD EUR estimates are generally more conservative than Arp's model with a minimum decline rate of 5%.

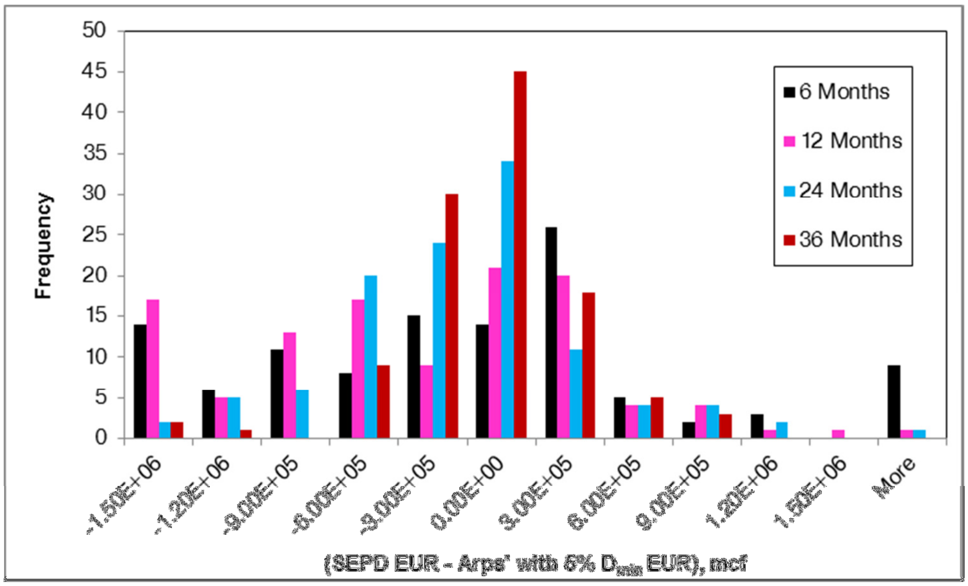

Fig. 64 – For 2007 Denton County wells, EUR estimates for the independent SEPD model and Arp' model with a minimum decline rate are converging towards similar values; the independent SEPD model provides more conservative EUR estimates in general.

4.7 Barnett Shale: Tarrant County Yearly Well Groups

Tarrant County is home to Fort Worth, Texas and has been one of the most actively drilled areas in the Barnett Shale. **Fig. 65** shows a Tarrant County map with the city of Fort Worth located in the center and well locations highlighted. We note the wells are not concentrated in any particular area of the county as they were in Denton County. Hence, we do not anticipate the type curve being quite as effective for Tarrant County as it is for Denton County. Nonetheless, we will still use type curves formed from 2004

Tarrant County wells to compare results against the independent forecasts of all subsequent yearly groups.

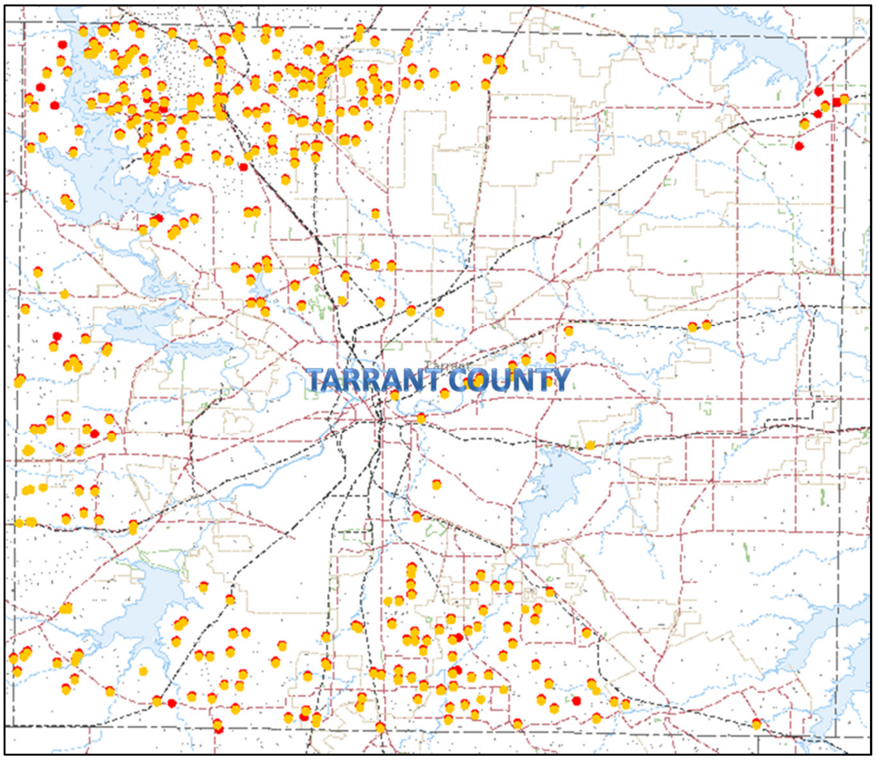

Fig. 65 – The Tarrant County wells are more spread out geographically than the wells we analyzed in Denton County.

Applying the independent SEPD model to the Tarrant County 2004 well group (**Fig. 66**), we see a large amount of uncertainty exists in the first 60 months. While all forecasts from 12 to 60 months provide errors to the EOH within ±10% (**Table 23**), the 30 year EUR values range from 125 to 167 Bcf. Looking closely, we see a bump in production around year 3. We suspect this is due to a field wide change in line pressure.

As we did with Denton County, we will use the parameters for the 36 month match and apply them to the 2005, 2006, and 2007 well groups.

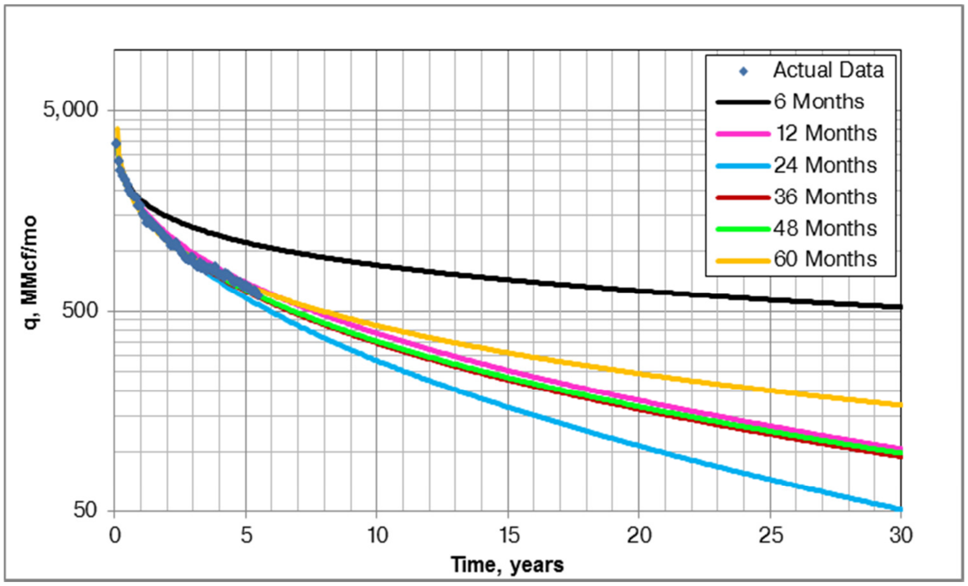

Fig. 66 – A large amount of uncertainty exists in the 2004 well group even with relatively smooth data; a discrepancy after year 3 is visible (believed to be a field wide change in line pressure).

Table 23 – 2004 Tarrant County Well Group Forecast Results

Months Used to Forecast	# Months Forecasted	Error to EOH	30 year EUR, Bcf
6	60	-35%	304
12	54	-7%	154
24	42	6%	125
36	30	3%	143
48	18	4%	145
60	6	-3%	167

Forecasting the 2005 Tarrant County well group with the independent SEPD model, we see (**Fig. 67**) another instance of terribly inaccurate forecasts when 12 months or less is used. Conversely, the 36 Month Type Curve forecasts provide remarkably accurate forecasts with any amount of data available. Further, the 30 year EUR forecast of ~267 Bcf is very close to the 262 Bcf (**Table 24**) forecast using 48 months of data with the independent SEPD model. This does not signify a high level of certainty in the EUR forecasts, but gives confirmation that the 2004 36 Month Type Curve (**Fig. 68**) will likely provide reasonable forecasts to the end of history for 2005 individual wells that make up the 2005 group.

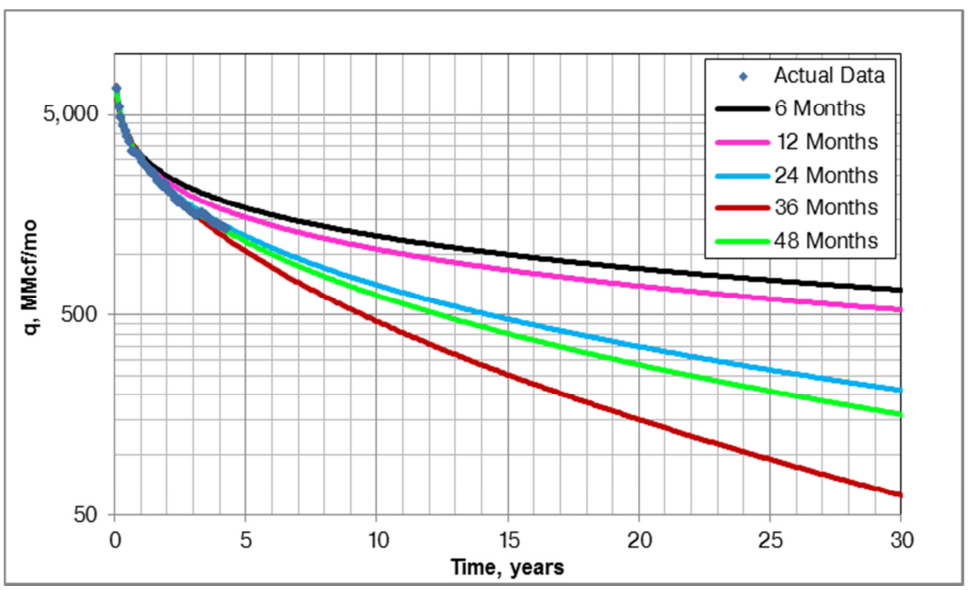

Fig. 67 – Independent SEPD forecasts of the Tarrant County 2005 well group need 24 months or more data to provide reasonable forecasts.

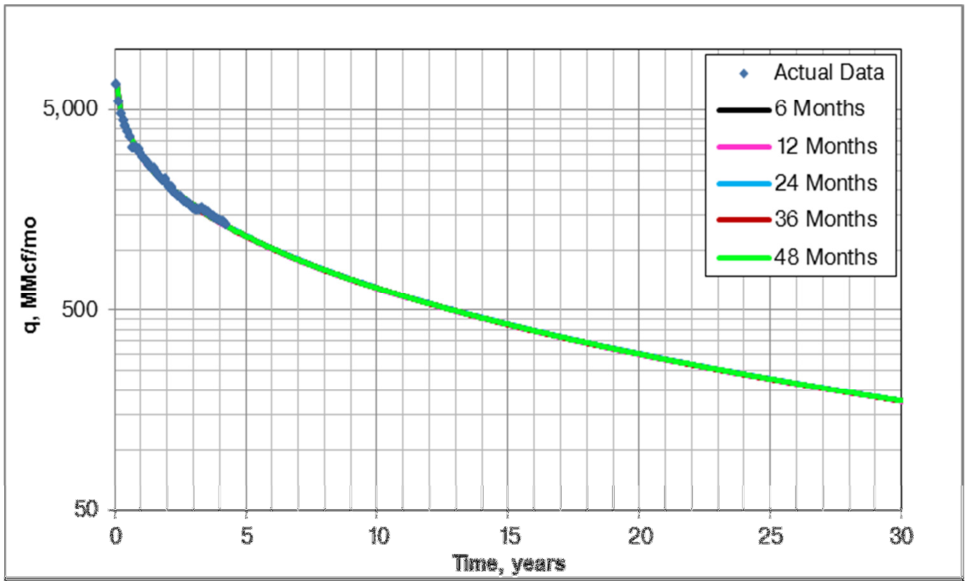

Fig. 68 – 36 Month Type Curve forecasts of the Tarrant County 2005 well group provide reasonable forecasts with only 6 months of data used.

Table 24 – 2005 Tarrant County Well Group Forecast Results

Months Used to Forecast	# Months Forecasted	2005 Independent		2004 Type Curve Match	
		Error to EOH	30 year EUR, Bcf	Error to EOH	30 year EUR, Bcf
6	45	-18%	454	0%	267
12	39	-12%	397	1%	265
24	27	-4%	284	-1%	267
36	15	7%	217	1%	266
48	3	2%	261	2%	266

The 6 month forecast using the independent SEPD model provide undesirable fits of future production for the Tarrant County 2006 Well Group (**Fig. 69**). Surprisingly, the 36 Month Type Curve only provides a more accurate forecast when 6 months of data is used (**Fig. 70**). Reviewing the forecast results (**Table 25**), we note the 2004 well group may not be a good analog for 2006. That being said, the fact that the type curve provides some kind of shape other than exponential decline when 6 months of data is used, makes the type curve forecast more accurate than the independent SEPD forecast. In future sections where individual wells are forecasted, we will use the 2004 well group to form a type curve to illustrate that even a far from perfect analog provides more accurate estimates than unaided forecasts when 6 and 12 months of data is used to forecast. We note the 30 EUR range provided by the type curve is not far off from the 30 year EUR found using 36 months of data with the independent SEPD model. In fact, the 12 month EUR using the type curve is within 1% of the 36 month EUR using the independent SEPD.

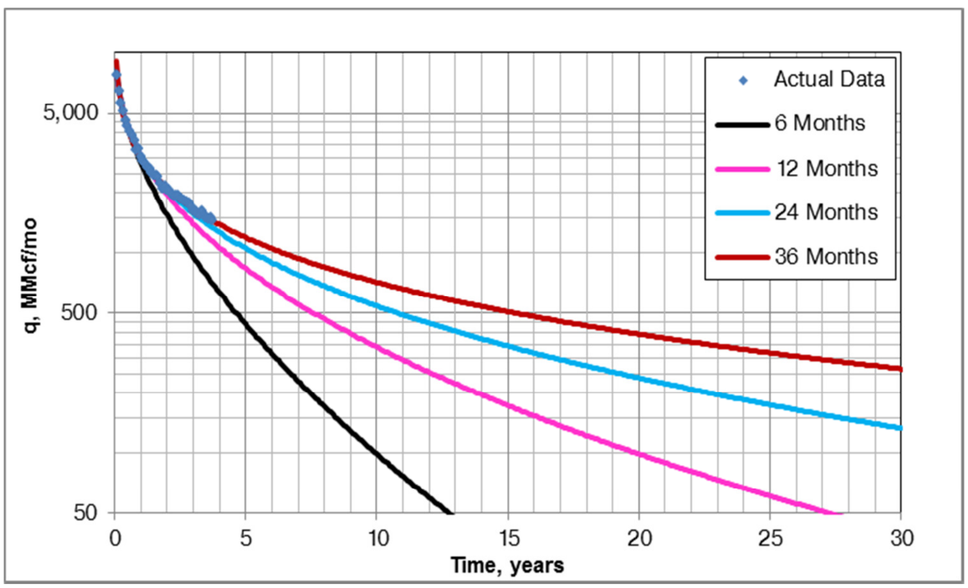

Fig. 69 – Independent SEPD model forecasts of the Tarrant County 2006 well group need 24 months or more data to provide reasonable forecasts.

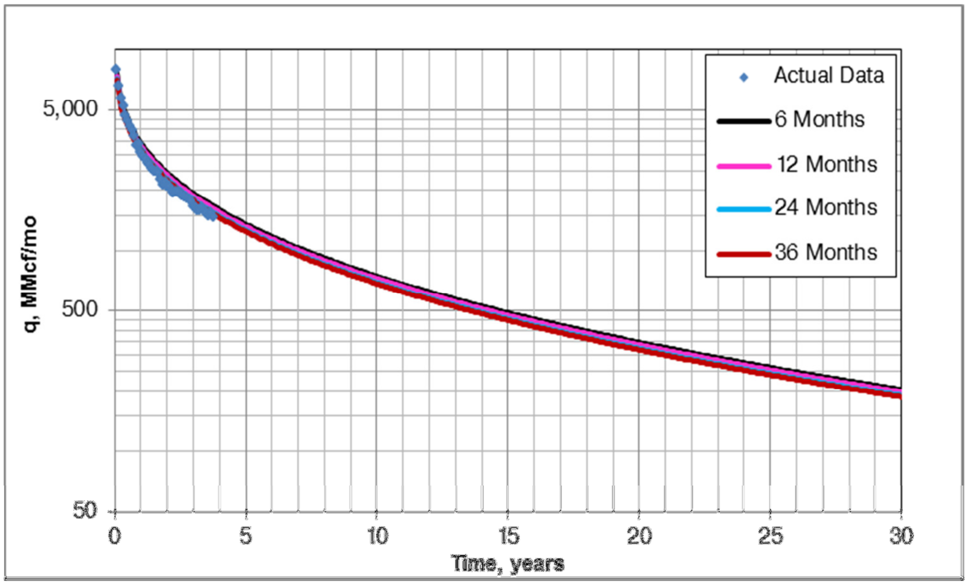

Fig. 70 – 36 Month Type Curve forecasts of the Tarrant County 2006 well group are all a bit optimistic but still more accurate than the Independent SEPD when 6 months of data is available.

Table 24 – 2006 Tarrant County Well Group Forecast Results

Months Used to Forecast	# Months Forecasted	2006 Independent		2004 Type Curve Match	
		Error to EOH	30 year EUR, Bcf	Error to EOH	30 year EUR, Bcf
6	39	24%	126	-13%	307
12	33	9%	191	-12%	298
24	21	5%	246	-8%	286
36	9	0%	296	-6%	282

For the Tarrant County 2007 well group, we see a lot more shape to the data early on than we did in prior years (**Fig. 71**) allowing the independent SEPD to forecast relatively accurately using limited data. We note the 24 month forecast is rather optimistic relative to the other forecasts. Although the 36 Month Type Curve shown in **Fig. 72** does not provide forecasts as accurate with 12 months of data, we note the errors and EURs are still reasonable (within -10% of 24 and 36 month independent forecast EURs - **Table 25**). The 2004 well group may not be an appropriate analog for the 2007 well group, but again we will apply the 2004 type curves to individual 2007 wells in the following sections to demonstrate that even a poor analog can provide useful estimates early in the life of a well. We assume operators will be able to use additional information (completions, water produced, etc.) to come up with better analogs than we use in this study.

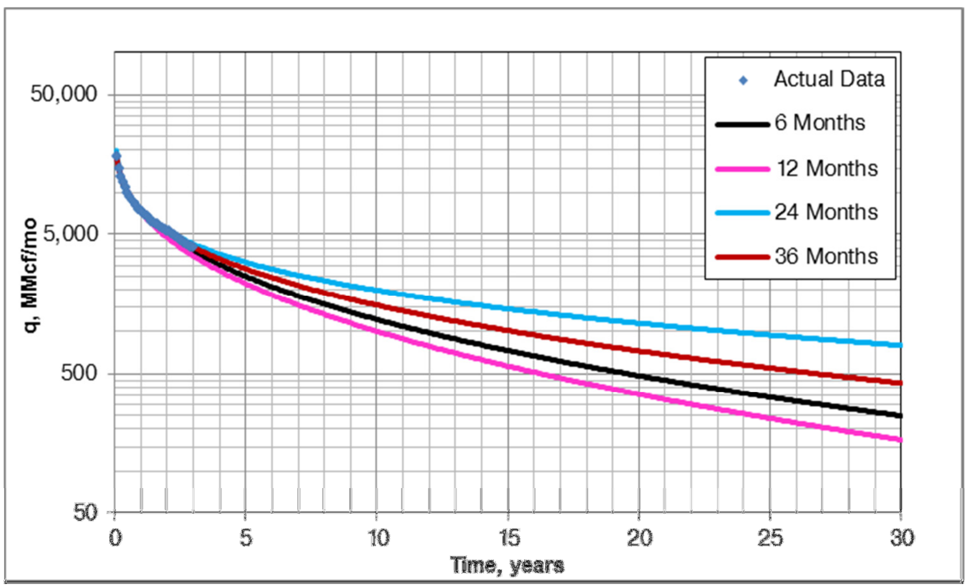

Fig. 71 – Independent SEPD model forecasts of the Tarrant County 2007 well group provide 6 month and 12 month forecasts that are remarkably accurate relative to the previous years.

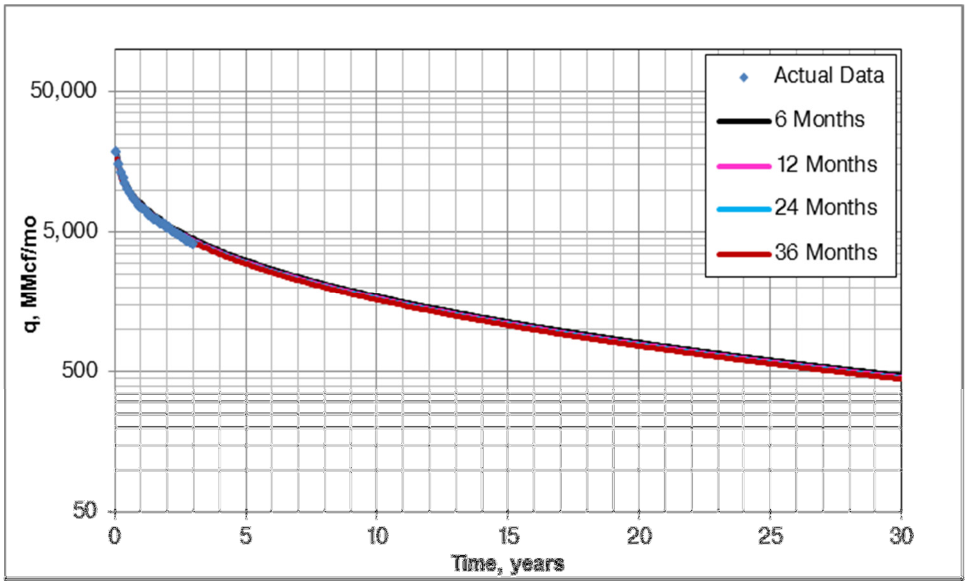

Fig. 72 – 36 Month Type Curve forecasts of the Tarrant County 2007 well group provide accurate forecasts early but slightly overestimate produced volumes.

Table 25 – 2007 Tarrant County Well Group Forecast Results

Months Used to Forecast	# Months Forecasted	2007 Independent		2004 Type Curve Match	
		Error to EOH	30 year EUR, Bcf	Error to EOH	30 year EUR, Bcf
6	30	2%	563	-9%	713
12	24	8%	502	-6%	692
24	12	-3%	784	-4%	680
36	0	NA	652	NA	673

4.8 Barnett Shale: Tarrant County 2004 Wells

In this section, 60 Tarrant County wells that began producing during 2004 are analyzed. Since 2004 is the year that we use to form type curves, there will not be any type curve analysis available for the 2004 wells. Histograms and tabulated statistics will be used to form conclusions about the models of interest. In this discussion, we only show the results for the type curve that provides the most accurate results.

First we take a look at the errors from the independent SEPD model and Arps' model with a minimum decline rate of 5% using 6 months of data in **Fig. 73** and **Fig. 74,** respectively. As we have seen time and time again, 6 months of data is insufficient to provide any reasonable level of accuracy. We do see some shape between the extreme outliers at both ends but if we had a type curve to use, that would likely be the route to go. Looking at the 36 month error distributions we see both models are tending towards normal where the independent SEPD forecast errors tend to be skewed slightly to the right and Arps' minimum decline errors tend to be skewed slightly to the left. Comparing the tabulated results in **Table 26** and **Table 27**, we note that both models have a problem when 48 months of data is used. Investigating individual well behavior, we find a large number of wells have a discrepancy around year 3 (also seen in the 2004 group). This is likely due a line pressure change field wide. The decline profiles often revert back to previous trends after a short time, allowing for more favorable errors when using 60 months of data. We see that without a type curve, Arps' model with a minimum decline rate of 5% provides a better estimate when 24 months or less data is used. The independent SEPD model provides more accurate forecasts using 36 and 60 months of data. Arps' model with a minimum decline rate provides the best estimate for 48 months right before the bump occurs. In general Arps' model with a minimum decline rate has been skewed left so a bump in production during the forecast period is favorable for the model bringing more errors within the -20% to 20% range.

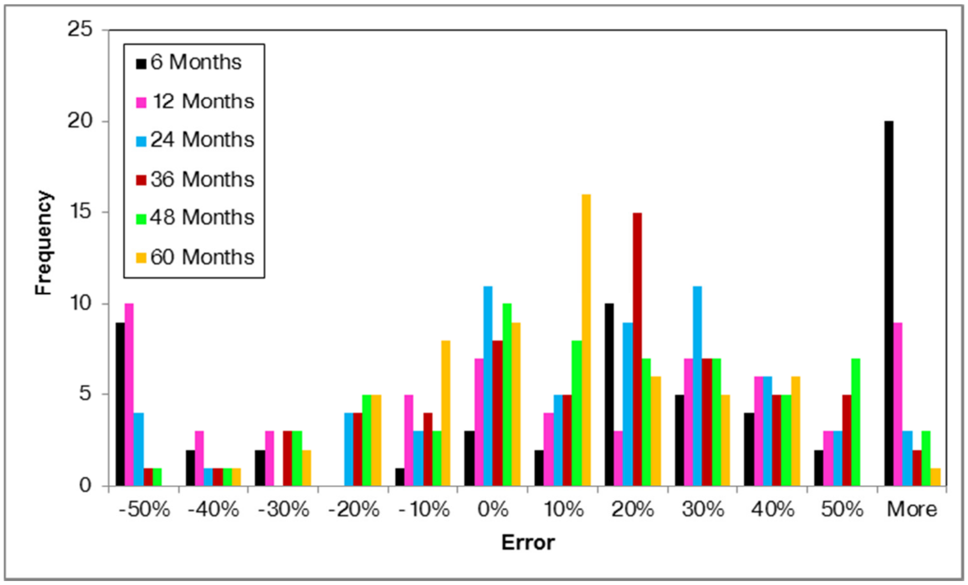

Fig. 73 – Independent SEPD model forecasts of Tarrant County 2004 wells using 6 months of data form an error distribution similar to other 6 month error distributions we have investigated - a large number of wells with positive errors; all error distributions are positively skewed.

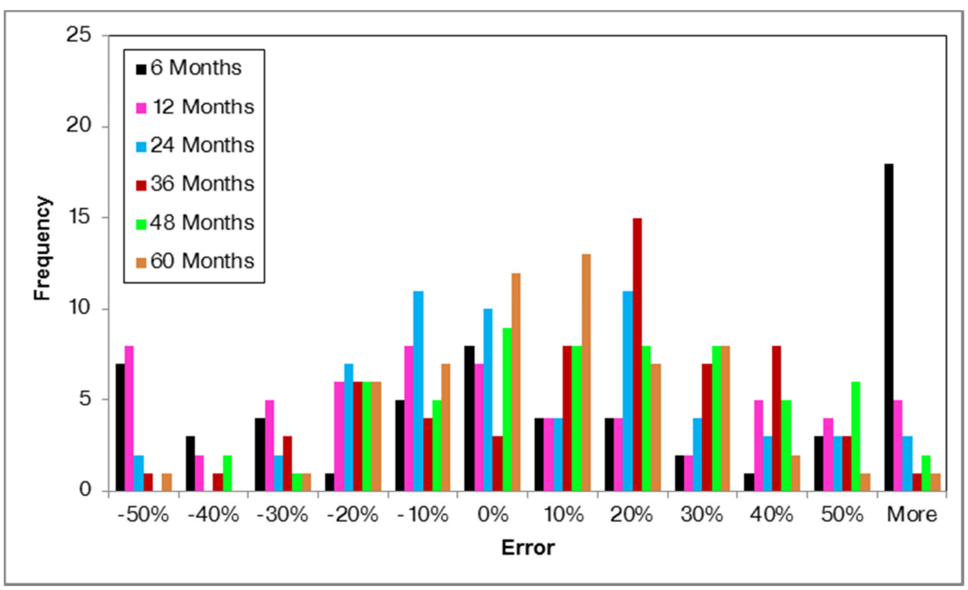

Fig. 74 – 6 month forecasts of 2004 Tarrant County wells using Arps' model with a minimum decline rate give extreme outliers on both ends of the error distribution; subsequent distributions continue to become more normal and slightly positive.

Table 26 - Error of 2004 Tarrant County Wells Using Independent SEPD

Months Used to Forecast	# Wells	SEPD Independent Error					
		<-50%	(-)	-20%<x<20%	-50%<x<50%	(+)	>50%
6	60	15%	28%	27%	52%	72%	33%
12	60	17%	47%	32%	68%	53%	15%
24	60	7%	38%	47%	88%	62%	5%
36	60	2%	35%	53%	95%	65%	3%
48	60	2%	38%	47%	93%	62%	5%
60	59	0%	42%	66%	98%	58%	2%

Table 27 - Error of 2004 Tarrant County Wells Using Arps with a Minimum Decline Rate of 5%

Months Used to Forecast	# Wells	Arps Minimum Decline of 5% Error					
		<-50%	(-)	-20%<x<20%	-50%<x<50%	(+)	>50%
6	60	12%	47%	35%	58%	53%	30%
12	60	13%	60%	38%	78%	40%	8%
24	60	3%	53%	60%	92%	47%	5%
36	60	2%	30%	50%	97%	70%	2%
48	60	0%	38%	50%	97%	62%	3%
60	59	2%	46%	66%	97%	54%	2%

Fig. 75 yields the same general conclusions about EUR estimates seen in Denton County well groups. The models converge to similar EUR estimates as more data becomes available and the independent SEPD model EUR estimates are more conservative in general. We also note that there are a large number of outliers when 24 months of data or less is used to forecast.

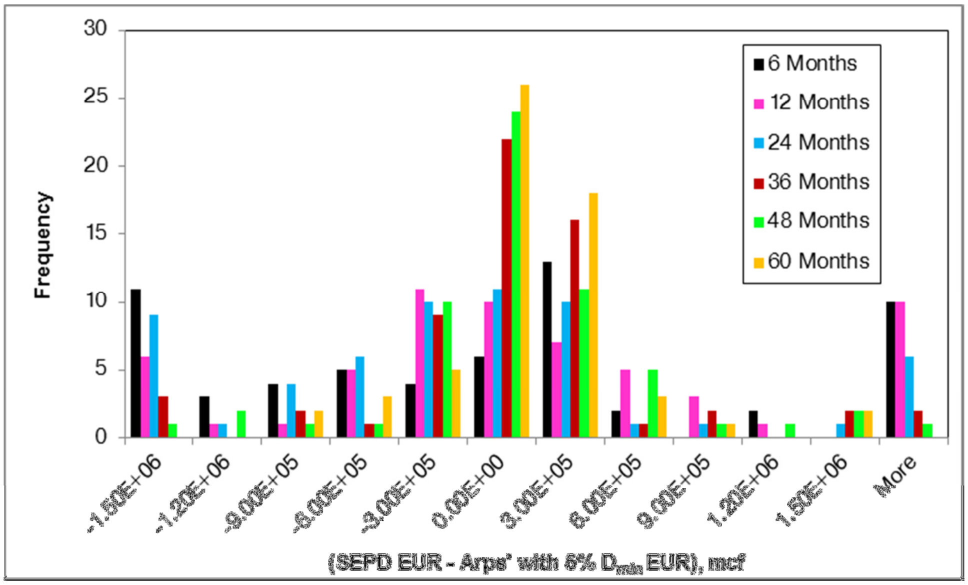

Fig. 75 - EUR estimates for 2004 Tarrant County wells using the independent SEPD model and Arps' model with a minimum decline of 5% yield similar results when 36 months of data or more is used to forecast.

4.9 Barnett Shale: Tarrant County 2005 Wells

We have 94 wells to analyze from Tarrant County drilled in 2005. In this section, we provide analyses with the independent SEPD model, Arps' model with a minimum decline rate of 5% and a 24 Month Type Curve. As with the previous cases, the type curve always provides more accurate results when 6 months of data are available.

The independent SEPD error distribution (**Fig. 76**) and the error distribution for Arps' model with a minimum decline rate (**Fig. 77**) are very similar in shape when 12 months of data is used. The independent SEPD errors tend to be more conservative as we have seen in every prior case. Both models still have a substantial number of outliers at both ends. The type curve error distributions (**Fig. 78**) all have very similar shapes with a large number of conservative estimates. The type curve's distribution is much tighter with fewer extremes than the other two models when 12 months of data or less is used.

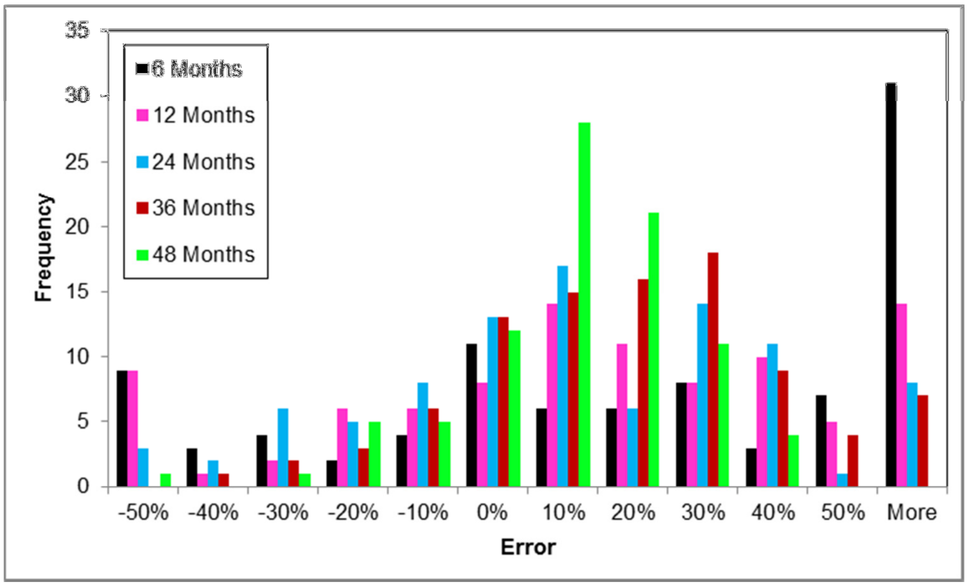

Fig. 76 – Independent SEPD model forecasts of Tarrant County 2005 wells using 12 months of data form an error distribution that is tending towards normal but still has extremes on both ends of the distribution.

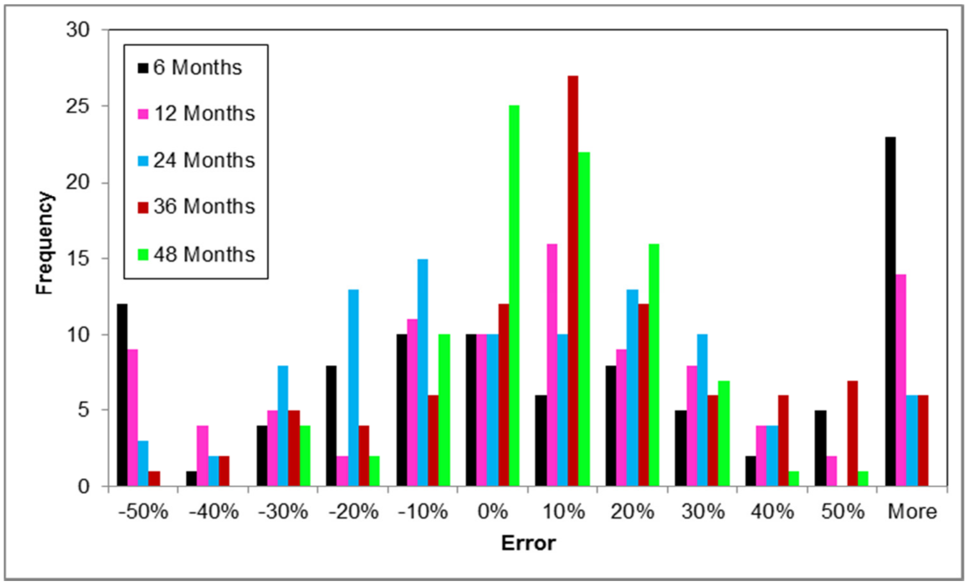

Fig. 77 – Forecasts of 2005 Tarrant County wells using Arps' model with a minimum decline rate do not appear normal until 36 months of data is used.

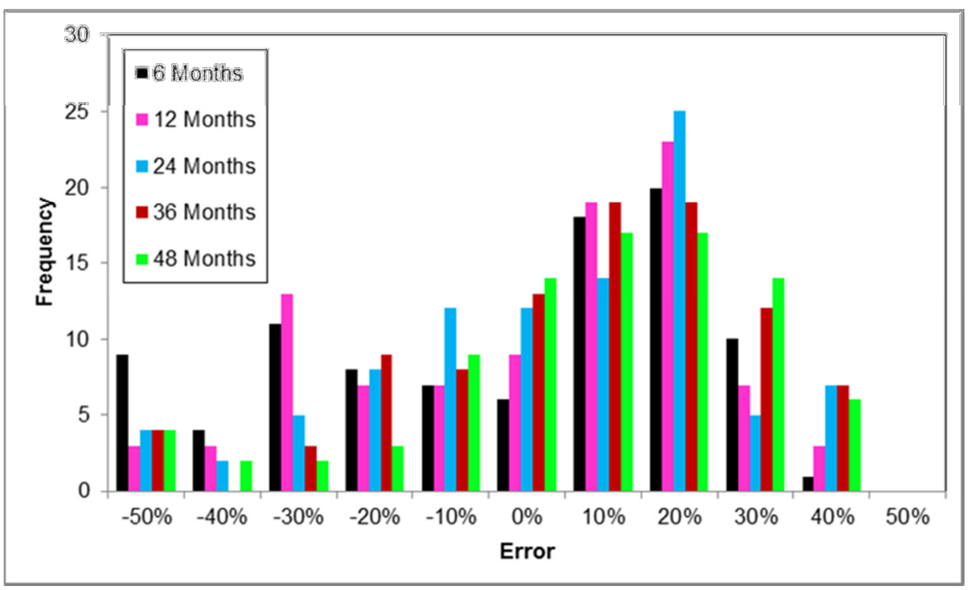

Fig. 78 – The 24 Month Type Curve error distributions for 2005 Tarrant County wells are skewed left and have relatively few outliers.

Investigating the 36 month forecast, we see errors from Arps' model with a minimum decline rate of 5% form a distribution very close to normal. The error distribution from the independent forecasts using 36 months of data has not taken the normal shape yet and contains a large number of positive errors. We recall the 2004 group had a bump in production between 3 and 4 years. We see a bump in production around 3 years for the 2005 group providing further evidence of our suspicion that a county wide (or field wide) change in line pressure likely occurred. Up to this point, errors from Arps' model with a minimum decline rate of 5% using 36 months of data have been ~50% positive. In this case the errors are 68% positive because of the bump in production around 3 years. The independent SEPD forecast errors using 36 months of data have been more positive than the Arps' model with a minimum decline rate for the same period in every field example up to this point. It comes as no surprise the positive error percentage in this case is the highest we have seen for 36 months (73%).

While a field wide bump in production can happen as it does in this case, we note in this study, the bump seen in the 2005 wells has the most significant impact on errors. We anticipate positive errors will gradually decrease for the 2006 and 2007 well groups when 24 months or more is used as we see in Denton County. The bump in production should occur at ~12 months and ~24 months for the 2006 and 2007 cases respectively. Investigating the tabulated results for Tarrant County 2005 wells in **Table 28- 30**, we note the type curve is the best option for the first 36 months. Both models start to converge and give more accurate forecasts than the 24 Month Type Curve when 48 months or greater is used. The independent SEPD model provides more conservative estimates than Arps' model with a minimum decline rate of 5% for all amounts of data used.

Table 28 - Error of 2005 Tarrant County Wells Using Independent SEPD

Months Used to Forecast	# Wells	SEPD Independent Error					
		<-50%	(-)	-20%<x<20%	-50%<x<50%	(+)	>50%
6	94	10%	35%	29%	57%	65%	33%
12	94	10%	34%	41%	76%	66%	15%
24	94	3%	39%	47%	88%	61%	9%
36	94	0%	27%	53%	93%	73%	7%
48	88	1%	27%	75%	99%	73%	0%
60	43	2%	42%	79%	98%	58%	0%

Table 29 - Error of 2005 Tarrant County Wells Using Arps with a Minimum Decline Rate of 5%

Months Used to Forecast	# Wells	Arps Minimum Decline of 5% Error					
		<-50%	(-)	-20%<x<20%	-50%<x<50%	(+)	>50%
6	94	13%	48%	36%	63%	52%	24%
12	94	10%	44%	49%	76%	56%	15%
24	94	3%	54%	51%	90%	46%	6%
36	94	1%	32%	61%	93%	68%	6%
48	88	0%	47%	83%	100%	53%	0%
60	41	0%	51%	85%	100%	49%	0%

Table 30 - Error of 2005 Tarrant County Wells Using 24 Month Type Curve

Months Used to Forecast	# Wells	SEPD 2004 24 Month Type Curve					
		<-50%	(-)	-20%<x<20%	-50%<x<50%	(+)	>50%
6	94	10%	48%	54%	90%	52%	0%
12	94	3%	45%	62%	97%	55%	0%
24	94	4%	46%	67%	96%	54%	0%
36	94	4%	39%	63%	96%	61%	0%
48	88	5%	39%	65%	95%	61%	0%
60	43	2%	33%	65%	98%	67%	0%

2005 Tarrant County EUR estimates (**Fig. 79**) for Arps' model with a minimum decline rate of 5% and the independent SEPD model vary significantly when less than 24 months of data are available to forecast evidenced by the large number of outliers. At this point we note the similarity in EUR estimates when 36 months or greater is used does not necessarily indicate that the level of uncertainty is decreasing. Rather, it only suggests the models are likely to provide similar forecasts moving forward.

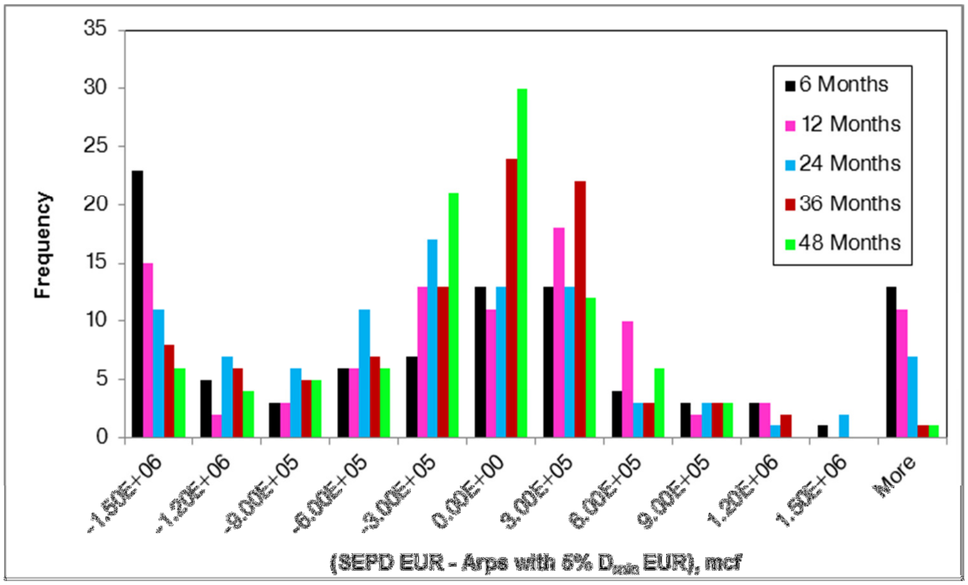

Fig. 79 – For the 2005 Tarrant County wells, differences in EUR estimates between the two models illustrate large discrepancies when 24 months of data or less is used; the number of outliers is dramatically reduced when 36 months or greater is used to forecast.

Summarizing this section we make the following notes:

- A bump in production occurs in many 2005 Tarrant County wells (believed to be due to a line pressure change); this skews the results slightly – making errors using independent SEPD and Arps' model with a minimum decline rate of 5% more conservative.
- SEPD provides the most conservative forecasts.
- The 24 Month Type Curve provides more accurate forecasts when 36 months of data or less is used.
- Arps' model with a minimum decline rate of 5% provides the most accurate reserves estimates for 48 and 60 months; independent SEPD estimates are within 8% and 6% respectively.

4.10 **Barnett Shale: Tarrant County 2006 Wells**

We have 115 Tarrant County wells to analyze that came on production during the year of 2006. As we noted in the previous section, we anticipate a bump in production around 24 months. Since the type curve usually provides the best results with 12 months or less, we do not anticipate as significant of an impact on our 36 and 48 month forecasts for the 2006 wells as it did for the 2005 wells.

The independent SEPD errors (**Fig. 80**) using 12 months of data or less are rather conservative as usual. When 24 months of data is used, the error distribution is tending towards normal with 42% of errors falling between -20% and 20%. Arps' model with a minimum decline rate of 5% provides a particularly nice looking error distribution (**Fig. 81**) relative to previous 24 month distributions; the 24 Month Type Curve (**Fig. 82**) still gives more accurate results with 61% of errors falling between -20% and 20% in contrast to the 51% for Arps' model with a minimum decline rate. If we did not have a type curve available, Arps' model with a minimum decline rate provides better forecasts than the independent SEPD model when 24 months or less is used.

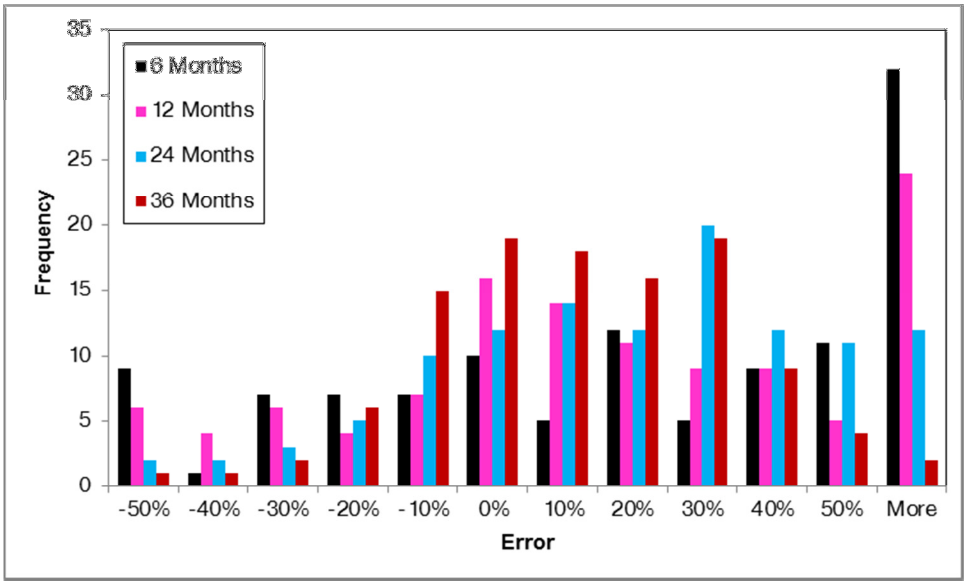

Fig. 80 – Independent SEPD model forecasts of Tarrant County 2006 wells tend to give more positive errors than negative errors for all cases; a relatively large number of outliers are seen for forecasts made with 24 months or less.

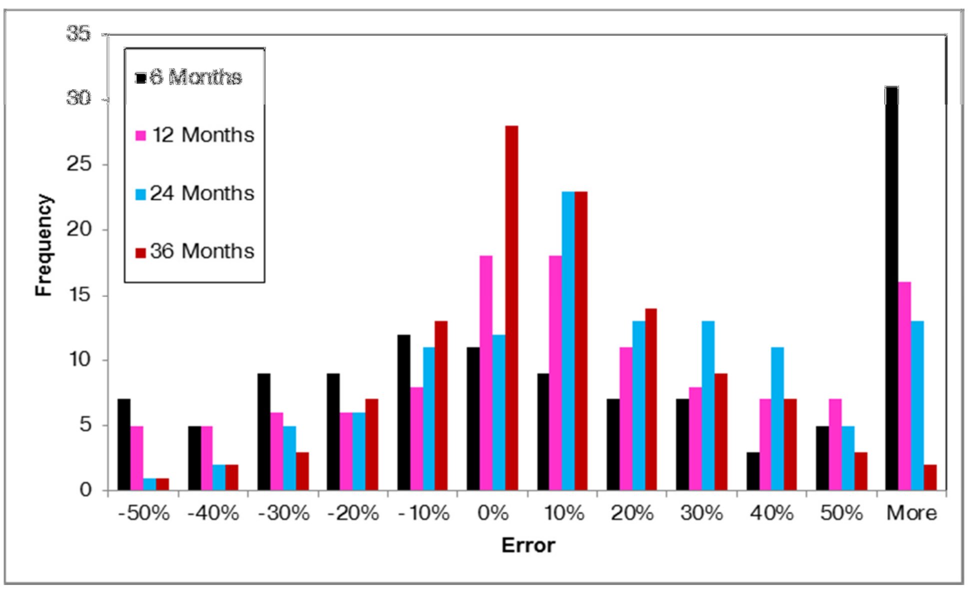

Fig. 81 – Forecasts of 2006 Tarrant County wells using Arps' model with a minimum decline have error distributions tending towards normal with as little as 12 months of data; a relatively large number outliers are seen for forecasts using 24 months or less.

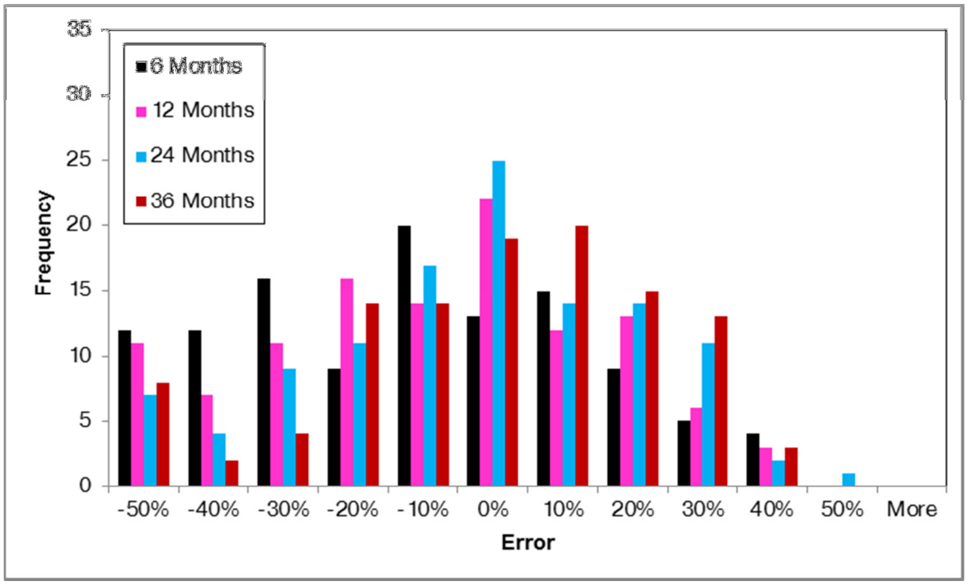

Fig. 82 – The 24 Month Type Curve error distributions are semi-normal with as little as 6 months used to forecast; all distributions appear to be tending toward negative values.

Investigating the tabulated results in **Tables 31-33**, we make several observations. First, the independent SEPD gives the most conservative forecasts across the board. The 24 Month Type Curve has more wells with errors between the -20% to 20% and -50% to 50% than either model when 24 months of data or less is used. The 24 Month Type Curve also has less wells with positive errors than the other two methods for all cases. Arps' model with a minimum decline rate provides more forecast errors in the -20% to 20% range when using 36 and 48 months than the independent SEPD. The independent SEPD has comparable number of forecasts with errors in the -50% to 50% range and more wells fall outside of the range on the right than the left – again showing that the independent SEPD method provides more conservative forecast even while converging. Both models have the highest number of positive errors when 24 months is used to forecast – not surprising as we expected a bump in production around that time.

The differences in EUR estimates between the independent SEPD model and Arps' model with a minimum decline rate of 5% show the same trend as previous cases. The SEPD model gives more conservative EUR estimates and the models converge towards similar estimates as more data becomes available (**Fig. 83**).

Table 31 - Error of 2006 Tarrant County Wells Using Independent SEPD

Months Used to Forecast	# Wells	SEPD Independent Error					
		<-50%	(-)	-20%<x<20%	-50%<x<50%	(+)	>50%
6	115	8%	36%	30%	64%	64%	28%
12	115	5%	37%	42%	74%	63%	21%
24	115	2%	30%	42%	88%	70%	10%
36	112	1%	39%	61%	97%	61%	2%
48	50	2%	44%	64%	98%	56%	0%

Table 32 - Error of 2006 Tarrant County Wells Using Arps with a Minimum Decline Rate of 5%

Months Used to Forecast	# Wells	Arps Minimum Decline of 5% Error					
		<-50%	(-)	-20%<x<20%	-50%<x<50%	(+)	>50%
6	115	6%	46%	34%	67%	54%	27%
12	115	4%	42%	48%	82%	58%	14%
24	115	1%	32%	51%	88%	68%	11%
36	112	1%	48%	70%	97%	52%	2%
48	50	4%	50%	76%	96%	50%	0%

Table 33 - Error of 2006 Tarrant County Wells Using 24 Month Type Curve

Months Used to Forecast	# Wells	SEPD 2004 24 Month Type Curve					
		<-50%	(-)	-20%<x<20%	-50%<x<50%	(+)	>50%
6	115	10%	71%	50%	90%	29%	0%
12	115	10%	70%	53%	90%	30%	0%
24	115	6%	63%	61%	94%	37%	0%
36	112	7%	54%	61%	93%	46%	0%
48	50	8%	52%	60%	92%	48%	0%

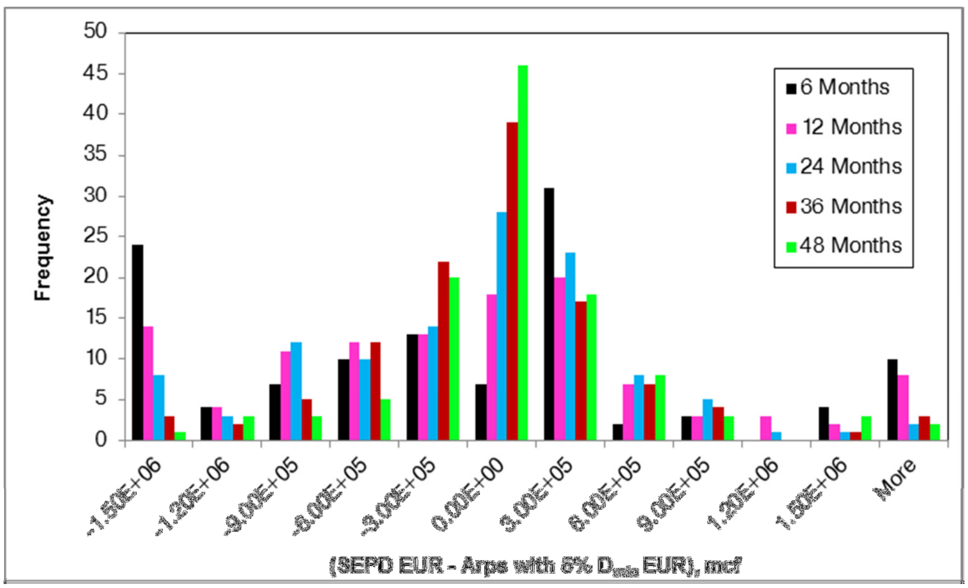

Fig. 83 – For the 2006 Tarrant County wells, differences in EUR estimates between the two models show the models converge to similar estimates as more data becomes available.

We note the following observations from the 2006 well analyses:

- SEPD forecasts are the most conservative for all amounts of data used.
- The 24 Month Type Curve provides more accurate forecasts when less than 24 months are available; the error distributions tend to be more negative for all cases.

- Arps' model with a minimum decline rate of 5% provides the most accurate estimates when 36 and 48 months of data is used.

4.11 **Barnett Shale: Tarrant County 2007 Wells**

The final data set is the largest with 267 wells from Tarrant County that were put on production in 2007. With the supposed line pressure issues occurring early on or not at all, these wells are much smoother and yield more consistent results than the wells from the previous years in Tarrant County.

Using 24 months of data, the independent SEPD model (**Fig. 84**), Arps' model with a minimum decline rate of 5% (**Fig. 85**), and 24 Month Type Curve (**Fig. 86**) error distributions are all tending towards a normal distribution with greater than 65% of forecast errors falling between -20% and 20% for all three cases. The type curve provides estimates that are more negative than positive. When 24 months of data is used to forecast, we are not surprised to see normal distributions since the forecasts lengths are shorter here than in previous cases.

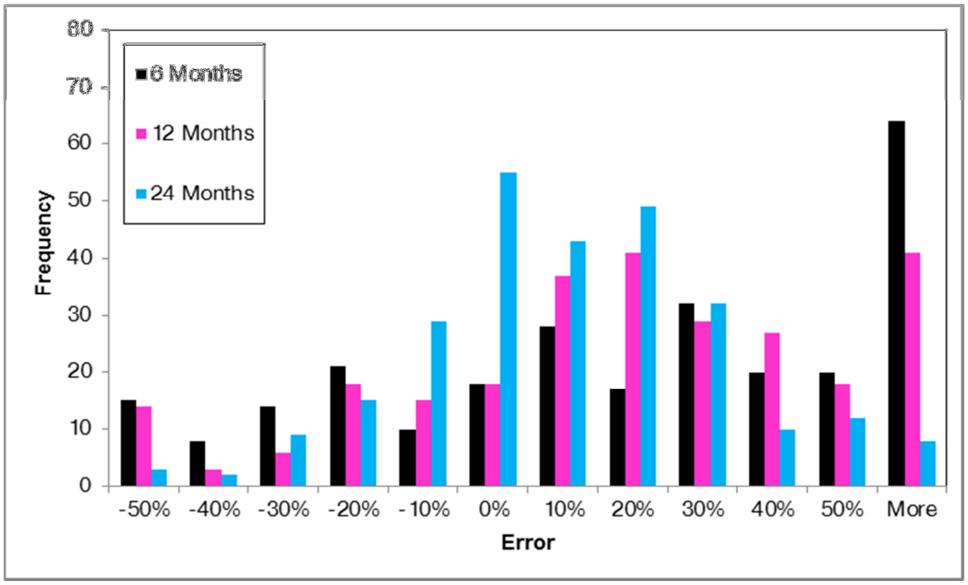

Fig. 84 – Independent SEPD model forecasts of Tarrant County 2007 wells using 24 months of data give an error distribution that is roughly normal; forecasts with 12 months or less are rather conservative.

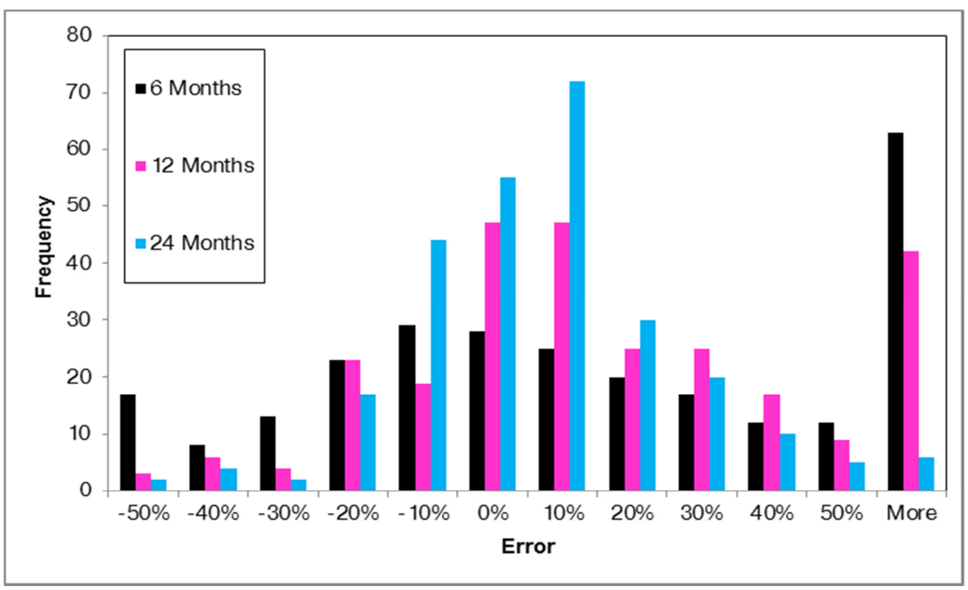

Fig. 85 – Forecasts of 2007 Tarrant County wells using Arps' model with a minimum decline rate have an error distribution that is close to normal with 24 months of data available to forecast.

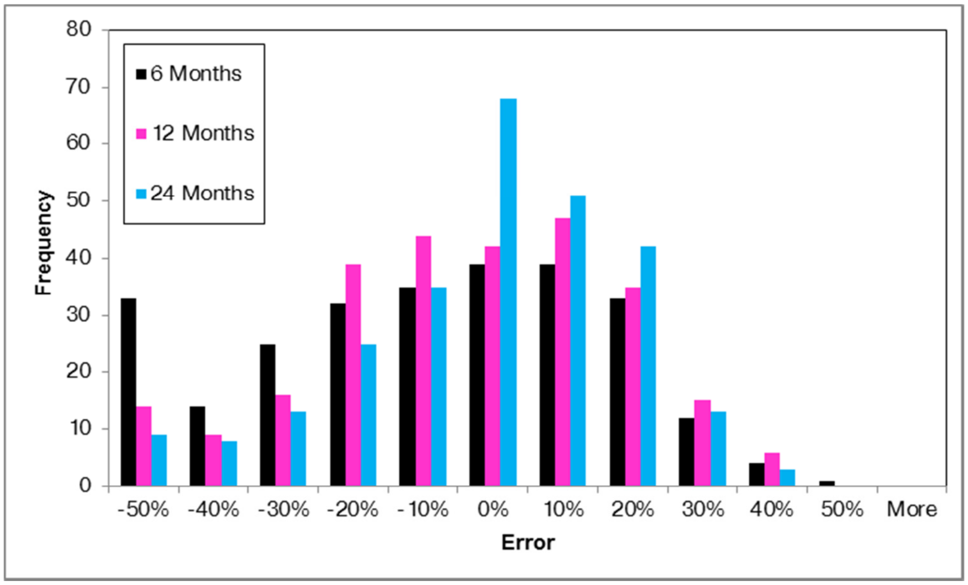

Fig. 86 – The 24 Month Type Curve error distribution for 2007 Tarrant County wells using 24 months of data is approximately normal with a mean error approaching the 0% to 10% range.

Investigating the tabulated results in **Tables 34-36**, we note the following:

- Independent SEPD model provides the most conservative forecasts for all amounts of data used.
- The 24 Month Type Curve provides the most accurate reserves estimates when 12 months of data or less is used; it tends to overestimate forecasted volumes.
- Arps' model with a minimum decline rate provides the most accurate forecasts when 24 and 36 months of data are available.
- When 36 months of data is used, independent SEPD and Arps' model with a minimum decline rate provide essentially the same accuracy with SEPD being the more conservative model.

Table 34 - Error of 2007 Tarrant County Wells Using Independent SEPD

Months Used to Forecast	# Wells	SEPD Independent Error					
		<-50%	(-)	-20%<x<20%	-50%<x<50%	(+)	>50%
6	267	6%	32%	27%	70%	68%	24%
12	267	5%	28%	42%	79%	72%	15%
24	267	1%	42%	66%	96%	58%	3%
36	97	1%	46%	78%	99%	54%	0%

Table 35 - Error of 2007 Tarrant County Wells Using Arps with a Minimum Decline Rate of 5%

Months Used to Forecast	# Wells	Arps Minimum Decline of 5% Error					
		<-50%	(-)	-20%<x<20%	-50%<x<50%	(+)	>50%
6	267	6%	44%	38%	70%	56%	24%
12	267	1%	38%	52%	83%	62%	16%
24	267	1%	46%	75%	97%	54%	2%
36	97	0%	51%	79%	100%	49%	0%

Table 36 - Error of 2007 Tarrant County Wells Using 24 Month Type Curve

Months Used to Forecast	# Wells	SEPD 2004 24 Month Type Curve					
		<-50%	(-)	-20%<x<20%	-50%<x<50%	(+)	>50%
6	267	12%	67%	55%	88%	33%	0%
12	267	5%	61%	63%	95%	39%	0%
24	267	3%	59%	73%	97%	41%	0%
36	97	6%	51%	69%	94%	49%	0%

4.12 **Summary of Field Results**

Forecasts of 321 Denton County wells and 536 Tarrant County wells using various amounts of production history provide valuable insights into how the SEPD model and Arps' model with a minimum decline rate of 5% handle real production data. When 6 months of data is used to forecast, a type curve approach provides better forecasts for all 6 year groups considered; when 12 months of data is used to forecast, a type curve provides better forecasts for all but 1 year group; when 24 months of data is used to forecast, a type curve provides better forecasts in 4 of 6 cases.

Without a type curve available, Arps' model with a minimum decline rate of 5% provides better forecasts to the end of history when 24 months of data or less is available. Arps' model with a minimum decline rate provides better forecasts to the end of history than the independent SEPD model in 6 of 8 cases where 36 months of data is used. For all cases and quantities of production used to forecast, EUR estimates for Arps' model with a minimum decline rate of 5% are more optimistic than EUR estimates for the SEPD model. EUR estimates for the models converge towards similar values as more data is used to forecast.

Linear flow ends during history for the 2004 Denton County well group. When 48 months and 60 months of data is used to forecast wells from the 2004 Denton County Group, the independent SEPD model provides the most accurate forecasts. Seeing linear flow end in a group of wells suggests long-term linear flow of 10+ years is unlikely.

A big note of caution should be mentioned here. Since a good number of the wells in this study exhibit linear flow to the end of history, we expect both models to perform well based on how they handled the long-term linear flow simulations. Unfortunately, if linear flow "ends tomorrow", the simulations suggest both Arps' model with a minimum decline rate and the SEPD model will overestimate reserves. If linear flow ends tomorrow, the SEPD model, being more conservative, will provide more accurate reserves forecasts.

V. CONCLUSIONS

5.1 Simulated Cases

- One of the most critical uncertainties concerning the ability of decline curve models to forecast reserves of shale gas wells is the time at which linear flow ends and a transition to boundary dominated flow begins.
- In cases where linear flow ends before ~5 years, neither model provides consistent reserves forecasts using 24 months of data or less.
- For the long-term linear flow cases (>8 years), both models provide error in reserves less than ±16% when 24 months or greater is used.
- Fracture interference at ~5 years poses problems for both models; SEPD is able to converge quicker than Arps' model with a minimum decline rate of 5%; both models overestimate reserves to varying extents when 24 months of data or greater is used.
- The SEPD model has lower error in reserves than Arps' model with a minimum decline rate of 5% for all forecasts in which linear flow ends at or before 5.5 years.

5.2 Field Data Cases

- A type curve is recommended when 24 months of data or less are being used to forecast individual wells.

- Independent SEPD forecasts of yearly well groups with 12 months of data or greater provides remarkably accurate estimates of gas produced to the end of history; 7 of 8 group forecasts using 12 months of data have error within ±7%.
- Independent SEPD forecasts provide more conservative estimates in general than Arps' model with a minimum decline rate of 5%.
- Field data shows Arps' model with a minimum decline rate of 5% generally provides forecasts to the end of history that are slightly more accurate than the independent SEPD model forecasts.
- SEPD EUR estimates are more conservative than EUR estimates from Arps' model with a minimum decline rate of 5%.

5.3 General Conclusions

- A range of 0.01 to 100 for the SEPD parameter τ is suitable for matching simulated and field production data.
- Matching field data is more complicated than simulated data due to the large number of uncertainties.
- Until the duration of linear flow for the average well is known, we suggest using the SEPD model; the SEPD model has the theoretical ability to handle a transition to BDF better than Arps' and gives more conservative forecasts when the only flow regime seen during history is linear flow.

- Field and simulated cases confirm a type curve should be used if possible when 24 months or less is available.

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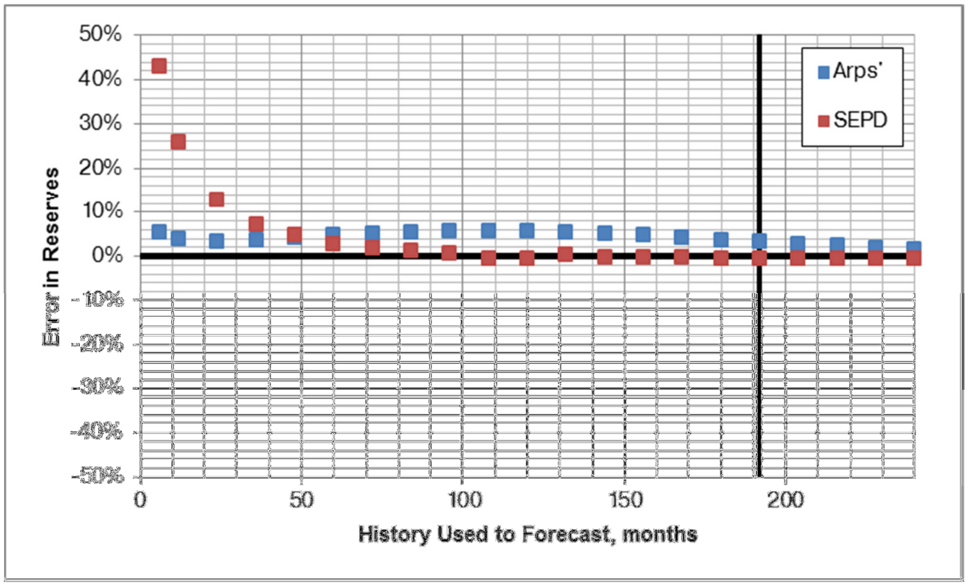
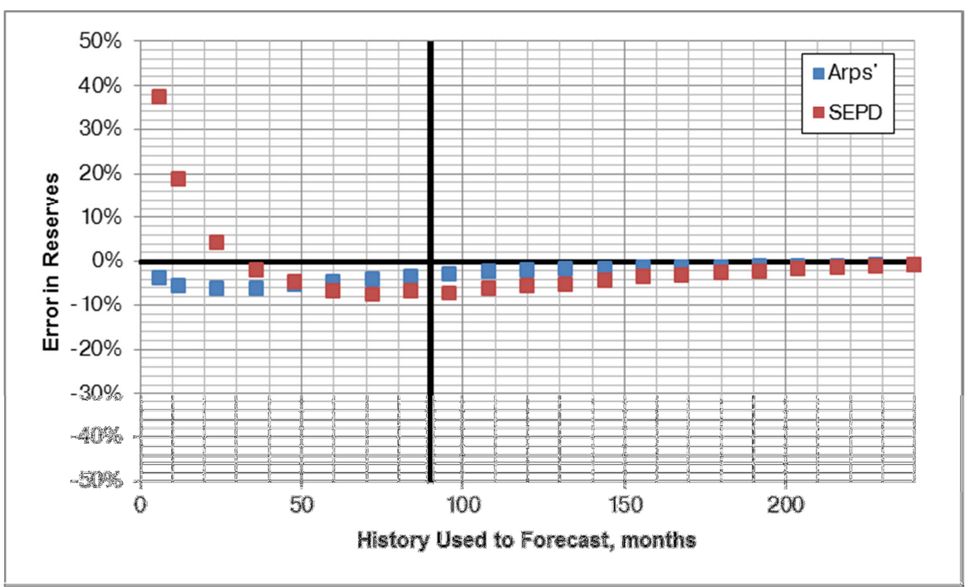
APPENDIX A

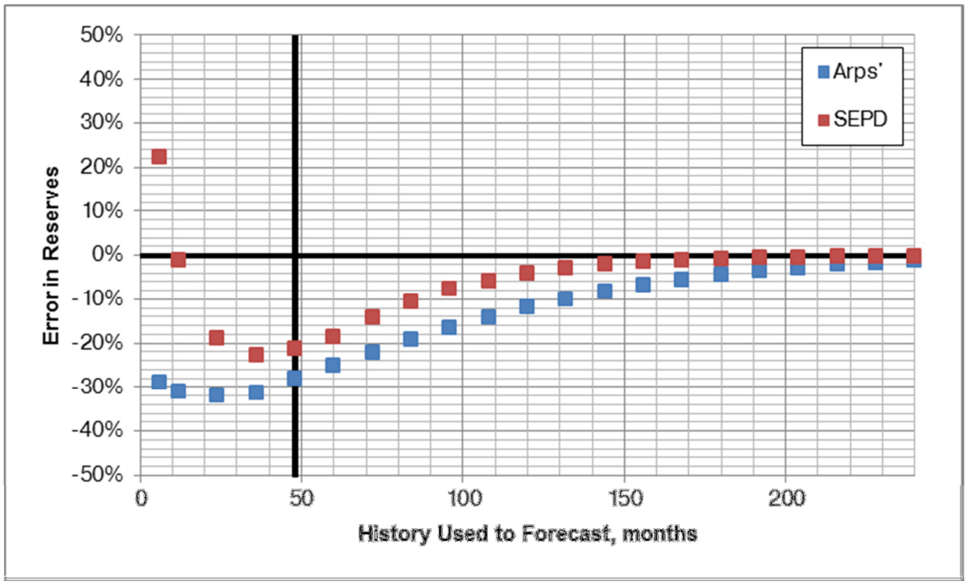
EUR Error Plots:



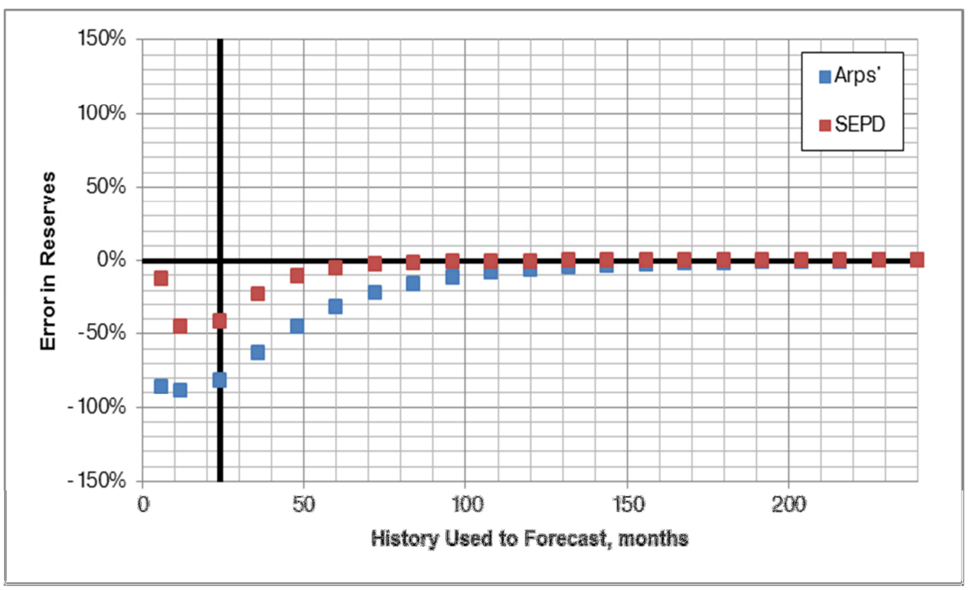
Case 1.1 EUR Error Plot



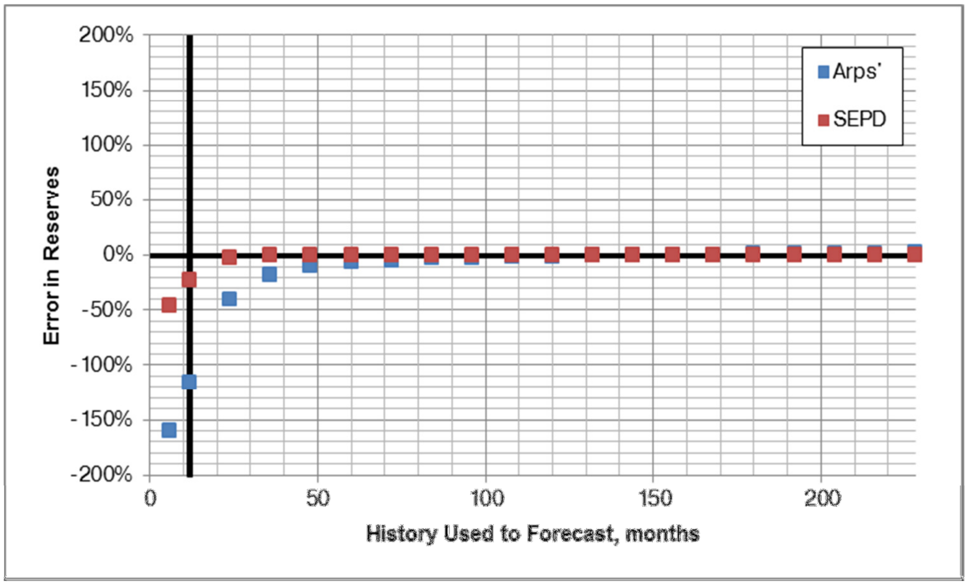
Case 1.2 EUR Error Plot



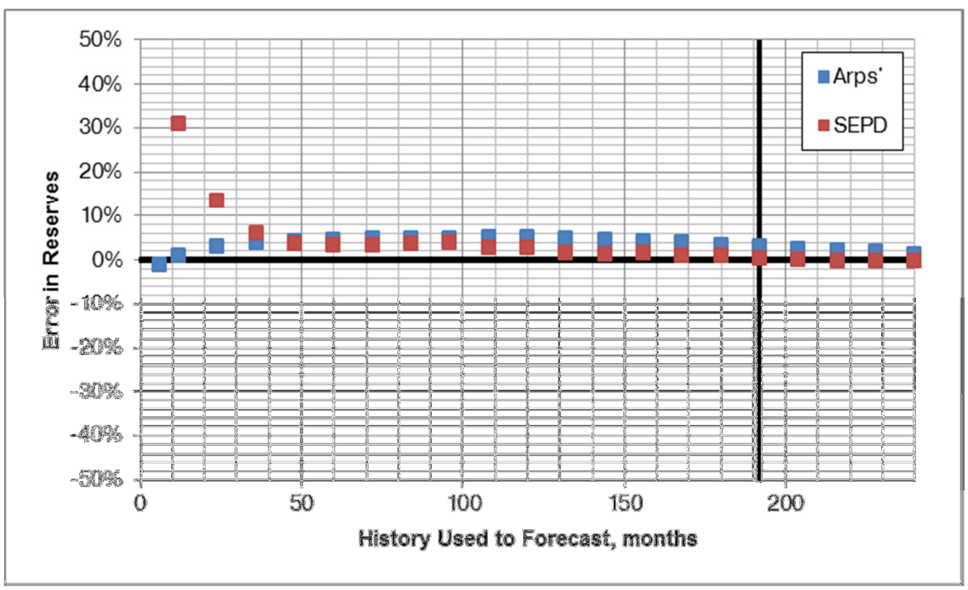
Case 1.3 EUR Error Plot



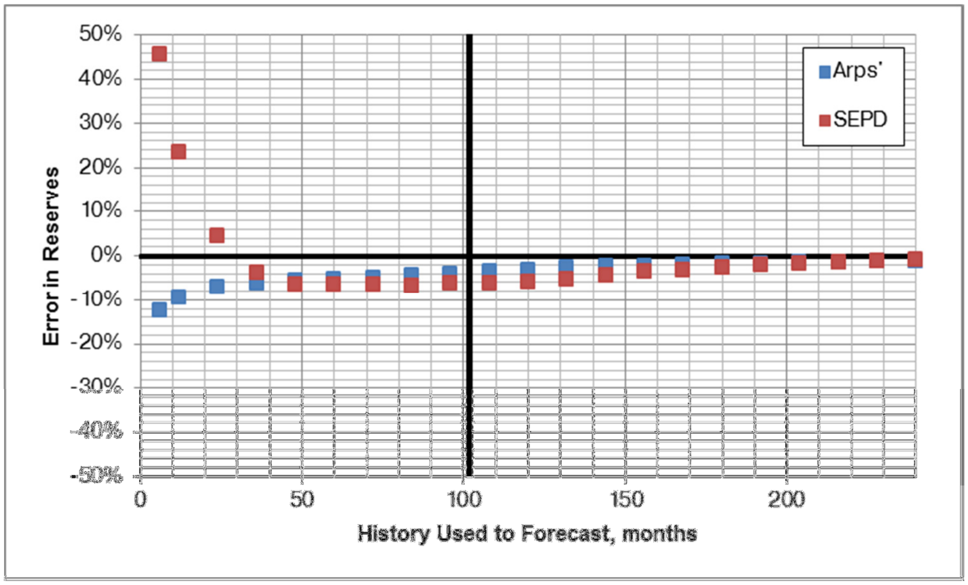
Case 1.4 EUR Error Plot



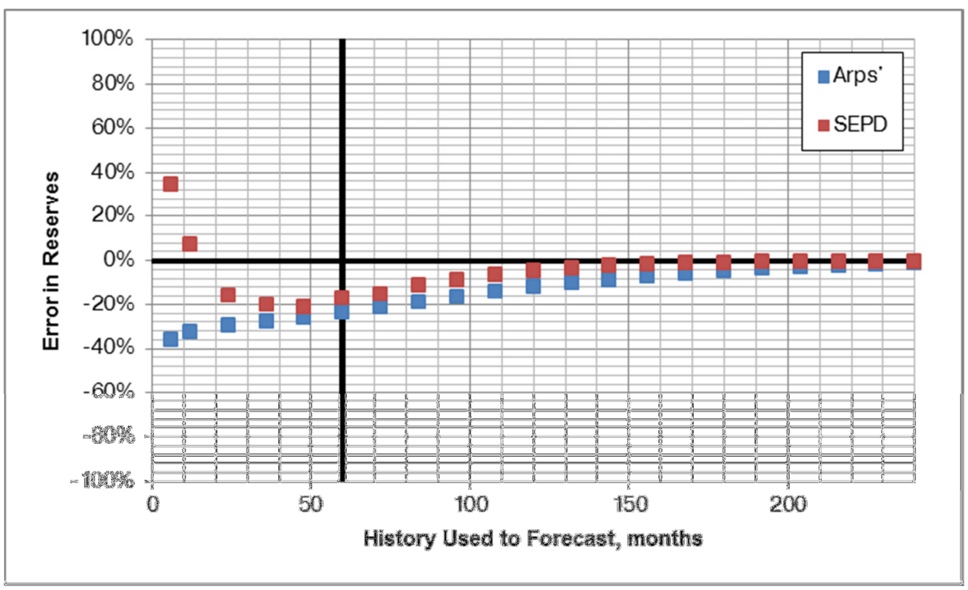
Case 1.5 EUR Error Plot



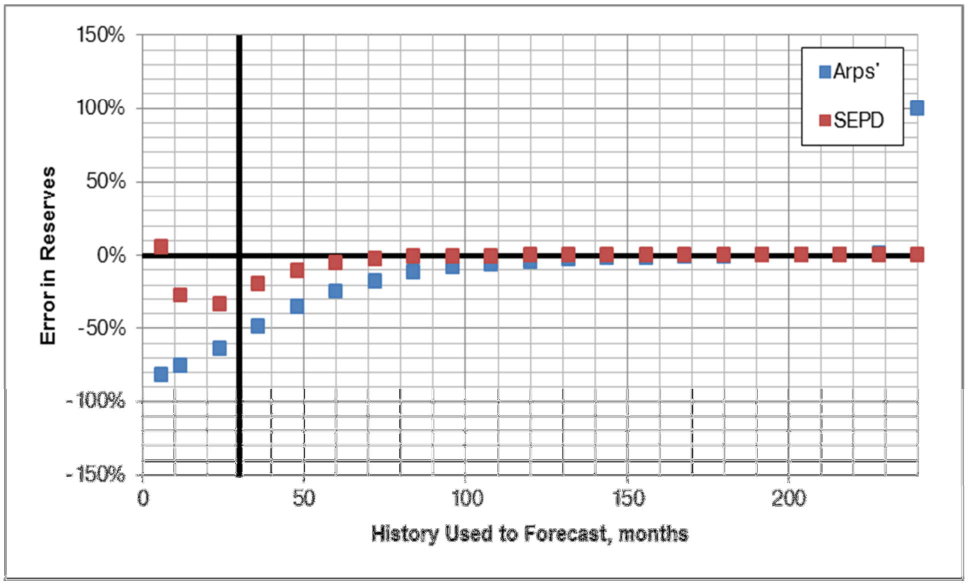
Case 2.1 EUR Error Plot



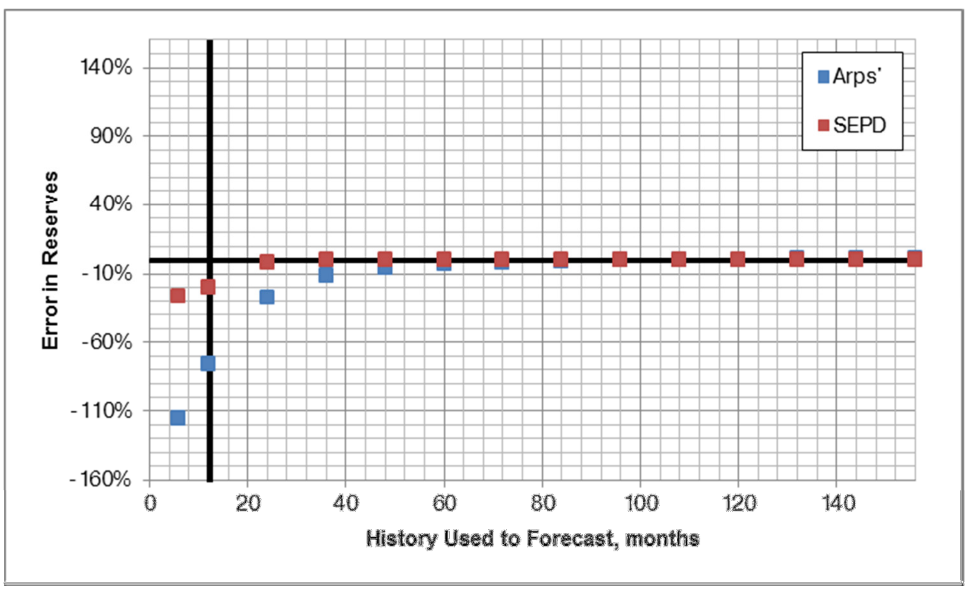
Case 2.2 EUR Error Plot



Case 2.3 EUR Error Plot



Case 2.4 EUR Error Plot

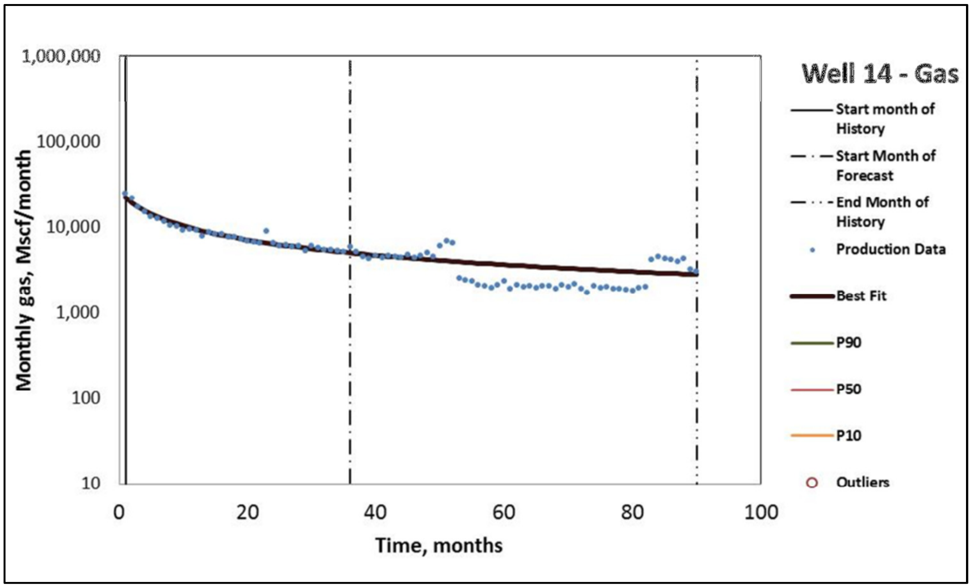


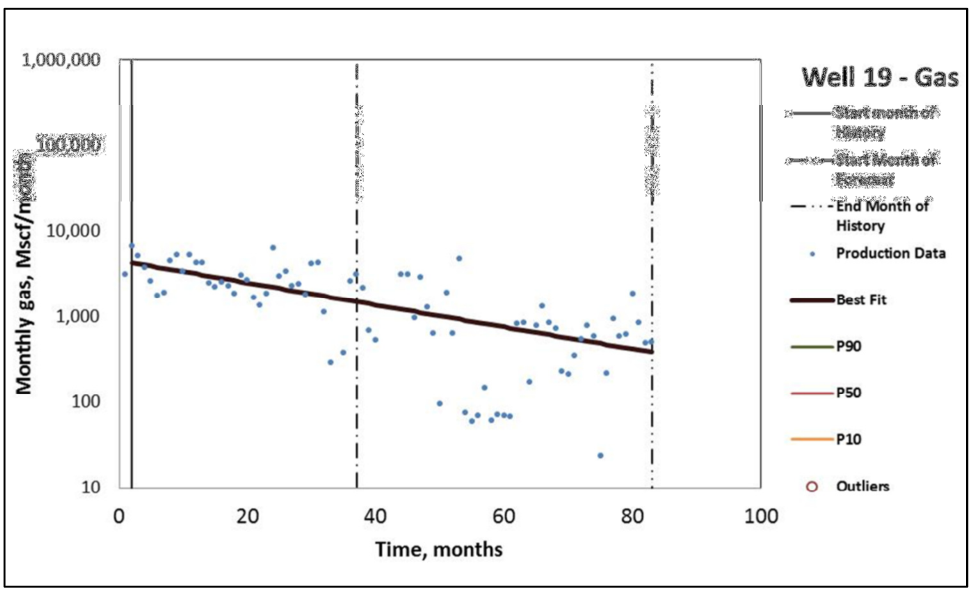
Case 2.5 EUR Error Plot

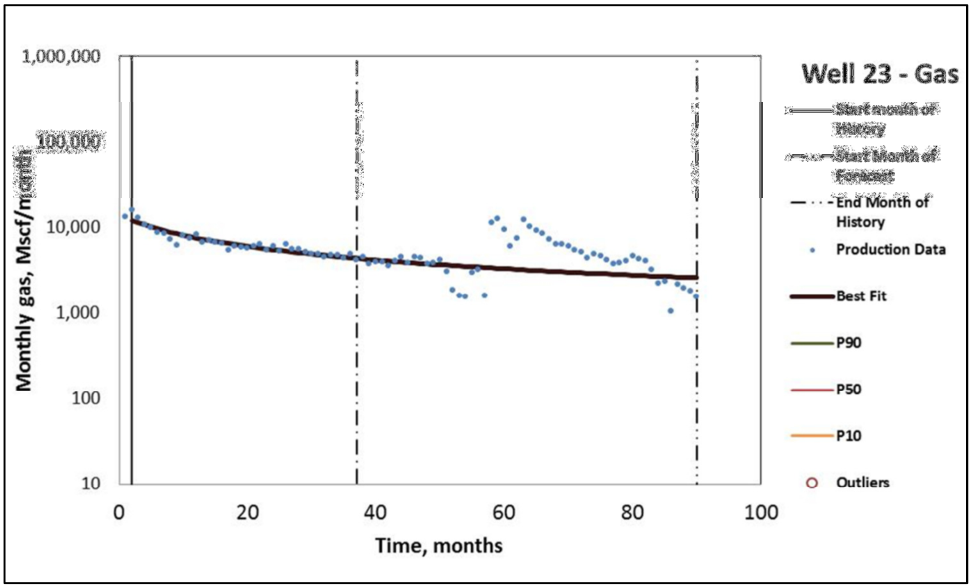
APPENDIX B

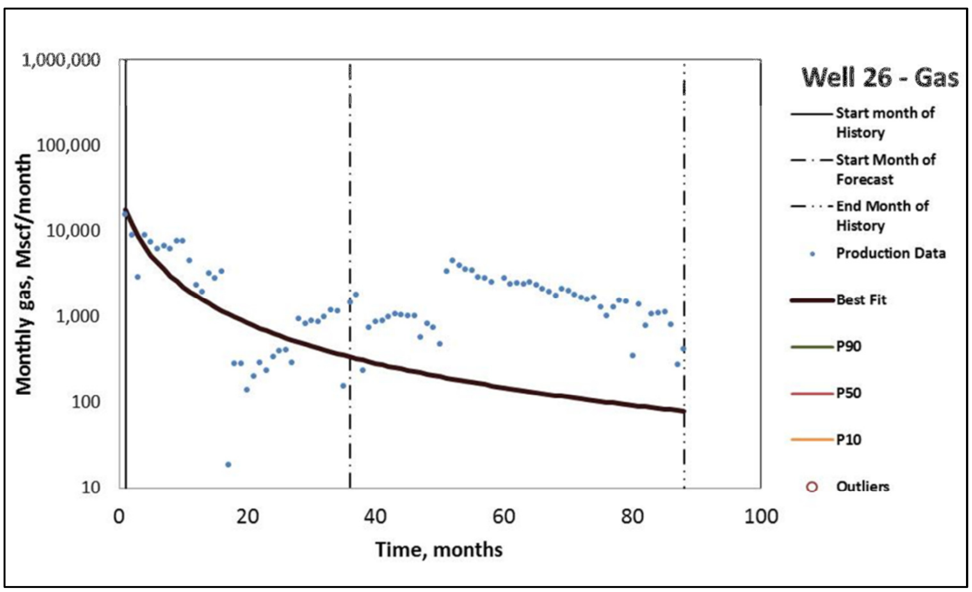
Examples of wells removed from study

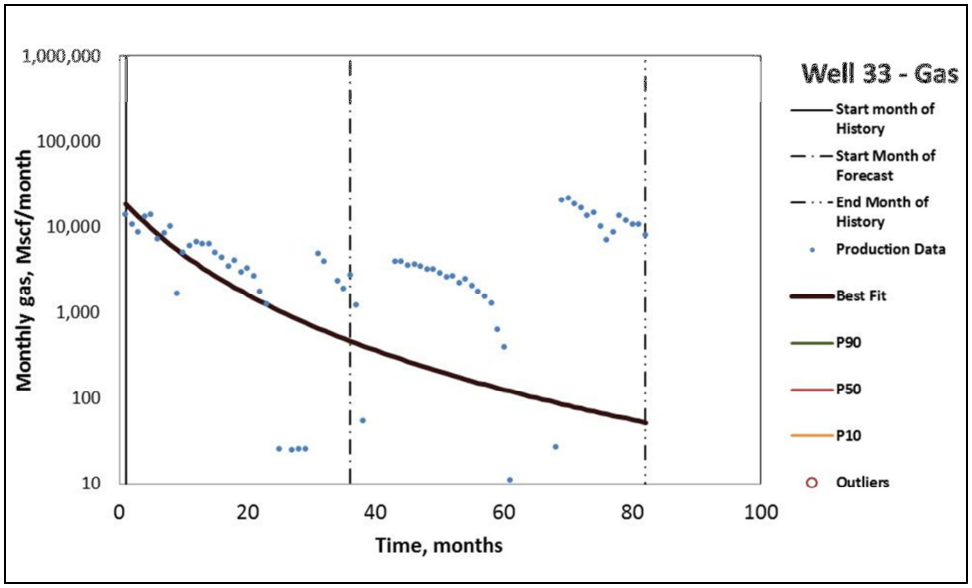
Denton County 2004:

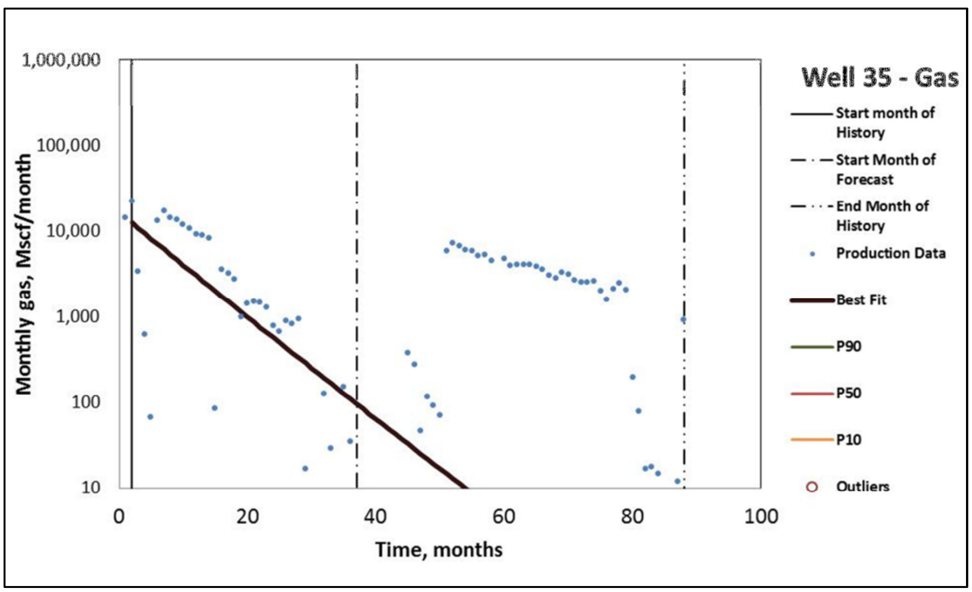


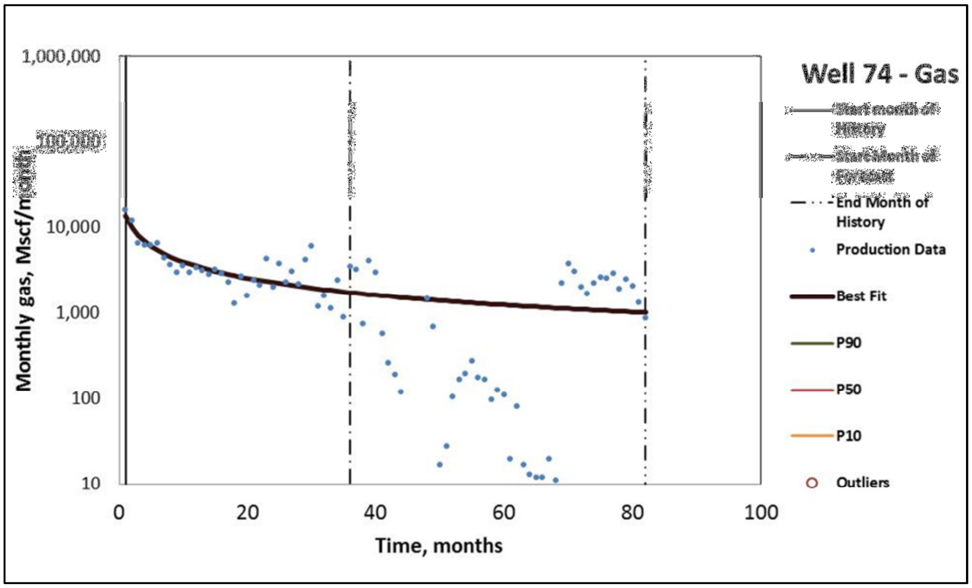



Well 23 - Gas
Start month of History
Start Month of Forecast
End Month of History
Production Data
Best Fit
P90
P50
P10
Outliers
Monthly gas, Mscf/month
Time, months
1,000,000
100,000
10,000
1,000
100
10
0
20
40
60
80
100


Well 26 - Gas
Start month of History
Start Month of Forecast
End Month of History
Production Data
Best Fit
P90
P50
P10
Outliers
Monthly gas, Mscf/month
Time, months
1,000,000
100,000
10,000
1,000
100
10
0
20
40
60
80
100


Well 33 - Gas
1,000,000
100,000
10,000
1,000
100
10
0
20
40
60
80
100
Monthly gas, Mscf/month
Time, months
Start month of History
Start Month of Forecast
End Month of History
Production Data
Best Fit
P90
P50
P10
Outliers


Well 35 - Gas
1,000,000
100,000
10,000
1,000
100
10
0
20
40
60
80
100
Monthly gas, Mscf/month
Time, months
Start month of History
Start Month of Forecast
End Month of History
Production Data
Best Fit
P90
P50
P10
Outliers



Well 74 - Gas
1,000,000
100,000
10,000
1,000
100
10
Monthly gas, Mscf/month
0
20
40
60
80
100
Time, months
Start month of History
Start Month of Forecast
End Month of History
Production Data
Best Fit
P90
P50
P10
Outliers

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