# **BAKKEN SHALE OIL PRODUCTION TRENDS**

A Thesis

by

TAN TRAN

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 2011

Major Subject: Petroleum Engineering

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Approved by:

Chair of Committee, Robert A. Wattenbarger

Committee Members, Bryan Maggard

Yuefeng Sun

Head of Department, Steve Holditch

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### **ABSTRACT**

Bakken Shale Oil Production Trends.

(May 2011)

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Chair of Advisory Committee: Dr. Robert Wattenbarger

As the conventional reservoirs decrease in discovering, producing and reserve, unconventional reservoirs are more remarkable in terms of discovering, development and having more reserve. More fields have been discovered where Barnett Shale and Bakken Shale are the most recently unconventional reservoir examples.

Shale reservoirs are typically considered self-sourcing and have very low permeability ranging from 10-100 nanodarcies. Over the past few decades, numerous research projects and developments have been studied, but it seems there is still some contention and misunderstanding surrounding shale reservoirs.

One of the largest shale in the United State is the Bakken Shale play. This study will describe the primary geologic characteristics, field development history, reservoir properties, and especially production trends, over the Bakken Shale play.

Data are available for over hundred wells from different companies. Most production data come from the Production Data Application (HDPI) database and in the format of monthly production for oil, water and gas. Additional 95 well data including

daily production rate, completion, Pressure Volume Temperature (PVT), pressure data are given from companies who sponsor for this research study.

This study finds that there are three Types of well production trends in the Bakken formation. Each decline curve characteristic has an important meaning to the production trend of the Bakken Shale play. In the Type I production trend, the reservoir pressure drops below bubble point pressure and gas releasing out of the solution.

With the Type II production trend, oil flows linearly from the matrix into the fracture system, either natural fracture or hydraulic fracture. Reservoir pressure is higher than the bubble point pressure during the producing time and oil flows as a single phase throughout the production period of the well.

A Type III production trend typically has scattering production data from wells with a different Type of trend. It is difficult to study this Type of behavior because of scattering data, which leads to erroneous interpretation for the analysis.

These production Types, especially Type I, II will give a new type curve matches for shale oil wells above or below the bubble point.

# **DEDICATION**

I dedicate my work to my worthy parents, Phung Chau and Hoang Chau, for their greatness, support, and encouragement ....to my lovely wife, Thanh Vo, and lovely daughter, Tam Tran, for their love and encouragement.....to my worthy aunt and uncle, Nancy Duong, Tim Duong, and lovely cousin, Caroline Duong, for their support and encouragement.

## **ACKNOWLEDGEMENTS**

First, I would like to acknowledge my esteemed supervisor, Dr. Robert. A. Wattenbarger for being a father, and for giving me valuable advice during my studies here at Texas A&M University. It has been an honor to be his student. I am eternally grateful to him.

I would like to also acknowledge my lovable committee members, Dr. Bryan Maggard, and Dr Yuefeng Sun, for their suggestions and contributions to my work.

I would like to give thanks to my lovable professor, Dr. William Bryant, for his generosity in helping me to complete this research.

I also would like to thank Tai Pham, Enron Oil & Gas Company (EOG) Resources for providing me with the data and giving me the chance to discuss and understand the problem in a broader way.

I also would like to note my special appreciation for my colleagues and friends who have discussed and gave suggestions to make my work easier.

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## **CHAPTER I**

#### INTRODUCTION

#### 1.1 Introduction

As the conventional reservoirs currently have been reduced in discovery, production and reserve, unconventional reservoirs, including tight sands, heavy oil, shale, and coalbed methane formations, are more remarkable in term of discovery, development, and of course, have more reserve. Also, with increasing pressure to be energy independent, the United States needs to look more into unconventional resources to help keep energy supply stable. One of the most valuable resources the U.S. has is its unconventional oil and gas. More fields have been discovered, Barnett Shale and Bakken Shale are the most recently unconventional reservoir examples.

Shale reservoirs are typically considered self-sourcing and have very low permeability ranging from 10-100 nano Darcies. Shale reservoirs cannot produce without massive stimulation treatment such as hydraulic fracture, steam injection (Ayers 2005). Over the past few decades, there was numerous research and developments, but it seems there is still some contention and misunderstanding surrounding shale reservoirs.

Shale oil reservoirs are shale plays, which produce matured oil, while oil shale are those rock contains solid Kerogen which have not been cooked enough to generate oil.

This thesis follows the style of *Society of Petroleum Engineers Journal*.

One of the largest shale oil plays in the United State is the Bakken Shale play. Advancements such as horizontal drilling and "Slick Water" fracturing have helped the Bakken climb to be the most desirable shale oil play in the North as well as giving the U.S. a step in the right, energy independent, direction. This study will describe the primary geologic characteristics, reservoir properties and especially the production trends over the Bakken Shale play. The Bakken Shale play is located in northwestern North Dakota and northeastern Montana. A large portion of oil generation and production is in the Williston Basin. Most of the Bakken formation is overpressure and matrix porosity is oil saturated. Since the formation permeability is really low, as low as 0.05 md, and oil production is mostly controlled by the natural fracture system, understanding the production characteristic of the Bakken Shale play is the main objective of this study.

# **1.2 Problem Description**

There are numerous major shale basins in the US which are shown in Figure 1.1. The Bakken Shale in the Williston Basin is one of the most active shale oil plays in the United States with approximately of 300 BBO in place. The reservoir has a thickness ranging from 0 to 140 feet, and it is getting thicker towards the center of the formation.

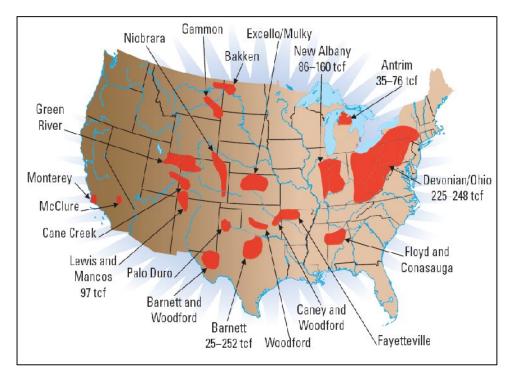


Figure 1.1 Major U.S Shale Basins (Lyle, D 2007).

The Bakken Shale production was originally slow and had been ignored because of the nature of the shale reservoir, which has very low permeability. Horizontal wells and hydraulic fracture technologies have lead the formation becoming one of the most desirable shale oil plays. Other factors include the help of the United States government in providing the tax credit in the Section 29 (1980-2002) which increase the interest in these unconventional shale reservoirs. This tax credit allowed a credit of \$3 per barrel of oil equivalent for the production from unconventional reservoirs (U.S Energy 2004).

Horizontal wells producing in the Bakken formation started from late 80s, with the first horizontal well in September 1987 by Meridian Oil Inc. As of June 23, 2010 the total number of wells in the Bakken formation is 2439 wells, including vertical and horizontal wells.

The Bakken reservoir production trends had not been studied much in the literature due to the complexity of the reservoir, which includes natural fracture network and very low permeability. Oil production in the Bakken Shale is mostly controlled by the natural fracture system, so understanding the production characteristic of the Bakken Shale play is the key to success for the operation companies in the area.

Oil and gas production from the Bakken is plotted against time on the log-log plot as shown in Figure 1.2.

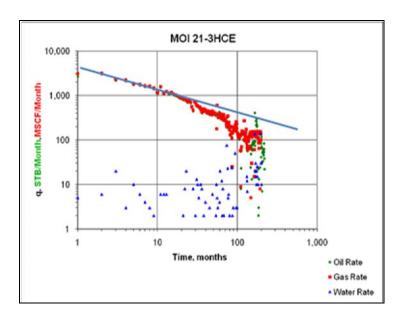


Figure 1.2 Log-Log Plot of Bakken Production Rate as Function of Time.

A half-slope is observed, indicating transient linear flow regime. This linear flow regime has been observed in many shale reservoir production wells and is the only flow

regime available for analysis. Three Types of production trends have been observed during the study, and it is important to understand reservoir mechanism for each Type of production trend. Three Types of the trends are shown in Figures 1.3, 1.4 and 1.5 with Type I; two exponential decline curves are shown, a rapid decline initially then changes to a steady and slow decline Figure 1.3. Type II shows a single exponential decline Figure 1.4.

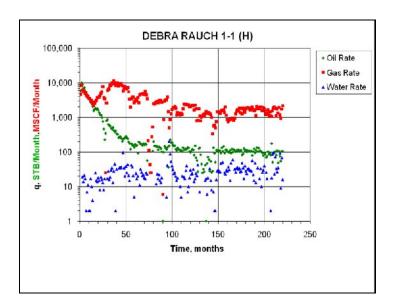


Figure 1.3 Type I Production Trend of Bakken Shale.

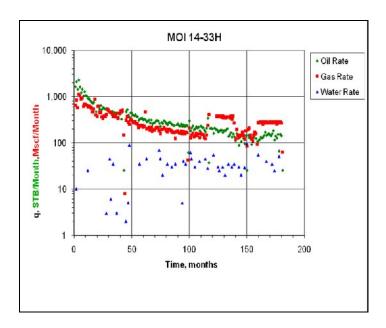


Figure 1.4 Type II Production Trend of Bakken Shale.

Type III: does not show any Type of decline curves Figure 1.5

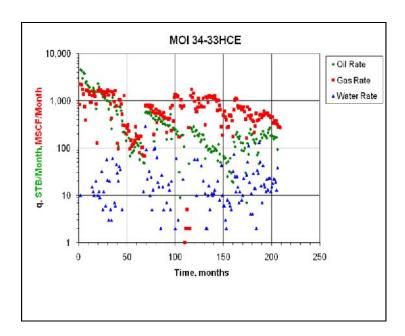


Figure 1.5 Type III Production Trend of Bakken Shale.

Each decline curve characteristic has an important meaning to the production trend of the Bakken Shale play especially Type I and Type II production trends. Type I production trend has the reservoir pressure drops below bubble point pressure and gas coming out of the solution. This can be seen on the GOR curve vs. time plot. The cause of reservoir drop below bubble point has been analyzed, and the production of oil in this behavior has driving force from the solution gas. In additional, two linear flow regimes have been observed by looking at the log-log plot of rate against time plot. To better confirm the observation, a simulation model is set using commercial software CMG to reproduce the decline behavior of the Type I production trend.

In a Type II production trend, oil flows linearly from the matrix into the fracture system, either natural fracture or hydraulic fracture. Reservoir pressure is higher than the bubble point pressure during the producing time and oil flows as a single phase throughout the production period of the well. GOR curve is almost constant during the production period. Linear flow behavior is observed in Bakken Shale play of Type II wells. This behavior is characterized by a half-slope on the log-log plot of the oil rate

versus time plot, or by a straight line of the  $\frac{1}{q_{oil}}$  vs.  $\sqrt{t}$  plot (square root of time plot).

A Type III production trend typically has scattering production data from wells with a different Type of trend. It is difficult to study this Type of behavior because of scattering data and it will lead to uncorrected interpretation for the analysis. So this study will not concentrate on this production trend but mainly on Type I and Type II.

### 1.3 Objectives

- To analyze the production data from 241 wells of the Bakken formation.
- To describe the reservoir mechanism under these production trends.
- To develop an excel VBA base computer program in order to use as a tool for analyzing.
- To generate the hydraulic fractures horizontal well in CMG to confirm Types of production trend.
- To develop the rate transient analysis procedure in order to determine reservoir properties, drainage volume and original oil in place (OOIP) for shale oil.

### 1.4 Methodology

Reservoir simulation will be used to reproduce the production trend of Type I, and II, Simulation will be modeled using commercial CMG package.

Diagnostic plots are included in the analysis to assist the calculation. These plots are log-log plot of the oil rate versus time plot,  $\frac{1}{q_{oil}}$  vs.  $\sqrt{t}$ ,  $cum_oil$  vs.  $\sqrt{t}$ . GOR vs. cumulative, oil rate vs. cumulative.

Superposition time and derivative functions will be applied to perform the flow regimes analysis. Smoothing derivative is also used to confirm the flow regimes observation.

OOIP will be estimated base on transient dual porosity model.

### 1.5 Organization of This Thesis

This study is divided into chapters. The outline and organization of this thesis are as follows:

Chapter I presents the introduction with the overview of the unconventional reservoir especially shale oil, problem description, objectives and methodology of the study.

Chapter II presents a comprehensive literature review included dual porosity model and its applications to liquids and gas. This will review basic concepts to cover all the necessary knowledge to complete this study.

Chapter III presents an overview of geology and field development history of the Bakken Shale formation.

Chapter IV presents the description of the well production trends. Reservoir mechanism of individual well is described for each Type of production trends. Simulation models will also give to confirm the observation.

Chapter V presents the field data analysis using different diagnostic plots in order to identify flow regimes, also present the technique of using superposition time functions and derivative functions in the analyzing.

Chapter VI OOIP estimation will be performed.

Chapter VII Summary and discussion from this work also includes the future recommendation.

### **CHAPTER II**

### LITERATURE REVIEW

#### 2.1 Introduction

Long-term linear flow has been studied previously by different authors to apply for low permeability reservoirs including tight gas and shale. There are different causes of linear flow and they have been studied long ago by many authors. Dual porosity reservoirs are one of the causes for linear flow, so this chapter will focus only on the dual porosity model and will be divided into four sections. The first section will review some of the previous work done for dual porosity models, followed by the second section, which reviewing previous work done for linear flow analysis. The third section will focus on reviewing work done for hydraulic fracturing and horizontal wells. The last section will review work done for production data analysis for oil and gas reservoirs.

### 2.2 Literature Review on Dual Porosity Model

The reason for reviewing the previous work in dual porosity models is because the Bakken Shale reservoir has a complicated natural fracture network intersecting with the matrix. This is the characterization of dual porosity model.

Warren and Root (Warren et al. 1962) was first proposed dual porosity model in the well test analysis with an idealized model of the matrix cube intersected by the natural fractures network. They modeled the natural fracture reservoirs as uniform homogeneous matrix blocks and separated them by fractures as shown in Figure 2.1.

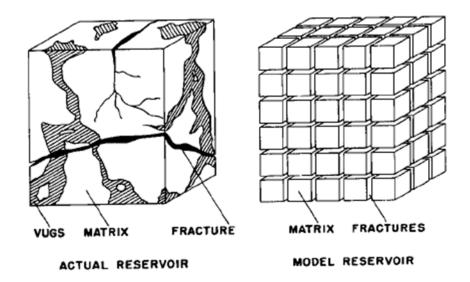


Figure 2.1 Warren and Root Dual Porosity Model (Warren et al. 1962).

In this model, the matrix blocks act as storage. The fluid inside is being produced while the fracture network provides the flow capacity. This model assumes that the flow only happens inside the fracture network, and the matrix feeds the fracture network with slightly compressible fluid. The Warren and Root model has considered the model in the pseudo-steady-state flow between the matrix and the fracture network. This consideration is not true for transient behavior in the shale reservoir system.

Kazemi et al. (Kazemi et al 1968) studied the Warren and Root model in order to apply the model for interference analysis. They used the Laplace Transform to derive the solutions for analysis and also to apply numerical techniques to solve for dimensionless pressure distribution. The conclusion of their study was that the Warren and Root model is not adequate or appropriate for applying to the interference behavior in the naturally fractured reservoirs.

Odeh (Odeh 1964) modeled the naturally fractured reservoir for infinite acting. His model assumed quasi-steady-state flow in the matrix, and the conclusion of his study was that the behavior between naturally fractured reservoirs and homogeneous reservoirs are similar during the transient response.

Kazemi (Kazemi 1968) proposed a model for naturally fractured reservoirs by using the slab matrix model. He suggested that the flow between the matrix blocks to the natural fracture networks is in the transient flow period, which is different from the Warren and Root model. The numerical simulation technique was used in order to obtain the solution. Two parallel straight lines were observed on the semilog plot, which present the wellbore storage effects in the early time, and the boundary effects in the late time region.

De Swaan (De Swaan 1975) presented a model for the transient dual porosity reservoirs. He used analytical model solution for the infinite acting reservoirs and compared the results to the numerical simulation of Kazemi. The shape of the matrix blocks may be approximated by regular solids, and he used heat flow theory to describe the internal pressure distribution flow in solids. The results between this analytical solution and numerical solution of Kazemi are similar, especially in the late time solution. The only limited in his model is that the presented model does not include a description of the transition between the two straight lines: fracture flow to the matrix flow.

Najurieta (Najurieta 1980) had a model which described the pressure transient behavior in the naturally fractured reservoirs. His model includes two types of matrix reservoir models including slabs and spheres matrix. The transient period in his model is similar to Kazemi model, but different from Warren and Root model.

Serra et al. (Serra et al. 1982) proposed a model for the dual porosity reservoirs. Their model described the transient flow from the matrix to the fracture networks of an infinite acting reservoir. The authors observed three flow regimes on the infinite acting reservoirs, which are referred to as flow regime 1, 2, and 3. Flow regimes 1 and 3 are similar to the Warren and Root model in the early and late time. The only new and interesting in Serra model was the flow regime 2, which shows half of the regime 1, 3 slope, in the intermediate time on the semilog plot.

Chen et al. (Chen et al. 1985) presented a model for the naturally fractured reservoir which is bounded. The model had identified five flow regimes referred to as flow regimes 1, 2, 3, 4, and 5. They gave the real time solutions for each of the five flow regimes. Flow regimes 1, 2, and 3 were the flow in an infinite reservoir, which had mentioned and described in Serra et al. (Serra et al. 1982). Flow regimes 4 is the result of the unsteady-state linear flow in the matrix and the pseudo-steady-state in the fracture network. Flow regimes 5 is the response of boundaries affected.

Gringarten (Gringarten 1984) provided a summary of the different between dual porosity reservoirs and also described the behavior of these reservoirs. He concluded that the dual porosity and the multi-layered reservoirs exhibited similar, and the two parallel semi-log may or may not exist depending on the well condition and characteristics of each medium. Also he concluded that the fissured reservoirs can be distinguished from the multilayered reservoirs only if the well is non-damaged or acidized. Base on the

summary, he also said that the multilayered reservoirs which have the wellbore storage constant is lower than that of non-damaged or acidized wells in fissured reservoirs.

Ozkan et al. (Ozkan et al. 1987) provided the procedure to analyze the matrix-fracture system for wells at constant pressure in a closed radial reservoir. Five flow regimes were identified and existed in fractured reservoirs. The Laplace transformation is used to derive dimensionless rate equations for these flow regimes. Flow regimes 1, 2, and 3 were the flow in an infinite reservoir, which had mentioned and described in Serra et al. (Serra et al. 1982). A flow regime 4 is the results of the unsteady-state linear flow in the matrix. It occurs when the outer boundary starts affecting the well, but the matrix boundary has not affected yet. Flow regimes 5 is the response of all boundaries affected. Also new ranges for  $\omega$  and  $\lambda$  were set for all 5 flow regimes.

El-Banbi (El-Banbi 1998) presented the first transient dual porosity solutions for linear reservoir with constant pressure case. The new solutions and Type curves development are for both infinite-acting and stabilized flow with either constant p<sub>wf</sub> or constant rate, and with or without skin. His conclusion was that for these linear reservoirs of oil and gas wells, no pseudo-radial flow is observed during the production period. Linear flow is the dominant flow regime throughout the well's production life. This model will be the main model which this study will use to analyze the reservoir behavior.

## 2.3 Literature Review on Linear Flow Analysis

Long term transient linear flow is a typical behavior of low permeability reservoirs such as: tight gas, shale oil and gas. This section will review the previous

work done on linear flow behavior, and on some calculation which will give the reservoir parameters such as: fracture half length, *OOIP*, *OGIP*, drainage.

El-Banbi (El-Banbi 1998) presented the first transient dual porosity solution for linear flow reservoir with constant pressure case. The new solutions and Type curves development are for both infinite-acting and stabilized flow with either constant p<sub>wf</sub> or constant rate, and with or without skin. His conclusion was that for these linear reservoirs of oil and gas wells, no pseudo-radial flow is observed during the production period. Linear flow is the dominant flow regime throughout the well's production life. This model will be the main model which this study will use to analyze the reservoir behavior.

Table 2.1 Interpretation Formulas for Linear Flow Regime, Constant pwf Production (El-Banbi 1998).

Constant p <sub>wf</sub> (Oil Production)	$\sqrt{k}A_c = \frac{125.1B\mu}{\left(p_i - p_{\text{wf}}\right)\sqrt{\phi\muc_tm_{CPL}}}$
	$V_p = 19.91 \frac{B}{(p_i - p_{wf})c_t} \frac{\sqrt{t_{ahs}}}{m_{CPL}}$
Constant p <sub>wf</sub> (Gas Production)	$\sqrt{k}A_c = \frac{1262T}{\left[m(p_i) - m(p_{wf})\right]\sqrt{(\phi \mu c_i)_i}m_{CPL}}$
	$V_{p} = 200.8 \frac{T}{[m(p_{i}) - m(p_{wf})](\mu c_{i})_{i}} \frac{\sqrt{t_{ehs}}}{m_{CPL}}$

Table 2.2 Interpretation Formulas for Linear Flow Regime, Constant Rate Production (El-Banbi 1998).

Constant Rate (Oil Production)	$\sqrt{k}A_c = \frac{79.65  qB\mu}{\sqrt{\phi  \mu  c_i m_{CRL}}}$
	$V_p = 8.962 \frac{qB}{c_t} \frac{\sqrt{t_{ehs}}}{m_{CRL}}$
Constant Rate (Gas Production)	$\sqrt{k}A_c = \frac{803.2  q_g T}{\sqrt{(\phi  \mu  c_t)_i} m_{CRL}}$
	$V_p = 90.36 \frac{q_g T}{(\mu c_t)_i} \frac{\sqrt{t_{ehr}}}{m_{CRL}}$

Table 2.1 and Table 2.2 above show the formula from his dissertation which can be used for calculation reservoir parameters for oil and gas of constant pressure and constant rate respectively.

Arevalo and Wattenbarger (Arevalo et al. 2001) investigated the long term linear flow caused by the parallel natural fractures and vertical flow in a high permeability streak. They presented an analytical model for parallel matrix-fracture of single phase. The conclusion were that long-term linear flow in tight gas wells may be controlled and developed by the anisotropy of natural fracture in the formation, and the drop of pressure in a higher permeability layer in a tight formation. By the end of their study, a complete

procedure of calculation for permeability, drainage area, reservoir pore-volume, and *OGIP* was presented.

Ibrahim et al (Ibrahim et al. 2006) used the similar analytical model as Arevalo and Wattenbarger (Arevalo et al. 2001) to study the rate sensitive of transient linear flow. In their studying, the transient linear flow for constant pressure solution depends on the level of drawdown. This result is very important for linear flow and different from radial flow solution. They also suggested that a correction factor need to use in the calculation process, which allows more accuracy in the determination of sqrt ( $kA_c$ ), and OGIP. Without the correction factor, errors can be up to 22%.

Helmy and Wattenbarger (Helmy et al. 1999) presented a technique to reduce the noise of production data due to multiple well shut-in periods of gas wells, which are producing linear flow at constant  $p_{wf}$ . The solution of this study is the application of the superposition principle in order to "filter-out" the scatter in the average production rate data, and construct a production trend without the effects of the shut-in periods.

Other papers including Agarwal (Agarwal 1979), Miller (Miller 1962), Nabor and Braham (Nabor et al. 1964) discussed and investigated long term linear flow.

### 2.4 Hydraulic Fracturing and Horizontal Wells Analysis

Low permeability reservoirs cannot produce without massive stimulation treatment such as hydraulic fracture. In additional, horizontal wells have helped the productivity of this low permeability reservoir increased significantly. These two component elements may develop several linear flow periods in dual porosity reservoirs. Understanding these two important elements is the key of success for operation

companies. Many authors had been studying and developing models for hydraulic fracturing and horizontal wells. This section will review some of previous work done on these two hydraulic fracturing and horizontal wells.

Valko and Economides (Valko et al 1996) studied the different between fractured horizontal wells and fractured vertical wells. Their solutions showed that the productivity could increase 5 times, when longitudinally fractured well is used, instead of fractured vertical wells. Their solutions used for both constant pressure and constant rate cases.

Raghavan et al. (Raghavan et al. 1994) presented new correlation procedures including a semi-analytical solution to determine long time performance for horizontal wells intercepted by transverse fractures. They also demonstrated that it is a good potential for improving well productivity by selectively perforating intervals between fractures.

Wattenbarger and Ramey (Wattenbarger et al. 1969) developed simulation model for fractured gas wells. They suggested that real gas pseudo pressure should be used in the analyzing fractured gas wells. This conclusion had been successfully used until now in the industry.

Agarwal et al. (Agarwal et al 1979) presented a numerical simulation solution for finite conductivity fractures. They used a 2D simulation model to modify the fracture tip and parallel fractures. The results can apply to infinite acting gas reservoir in either drawdown or buildup as long as the producing time is greater than the shut in time.

Bello and Wattenbarger (Bello et al. 2008) develop the transient model for multistage hydraulically fractured wells in shale gas formation. Five flow regimes were identified referred to as regimes 1, 2, 3, 4, and 5. They gave the real time solution for each of five flow regimes. Flow regime 1 is the result of early linear low from the fracture network to the well. Flow regime 2 is the result of transient linear flow through fracture and matrix systems. Flow regime 3 is the late linear flow of infinite acting reservoir, also described as matrix linear transient flow in large reservoir. Flow regime 4 is late linear flow of closed boundary reservoir, also described as transient linear flow from the matrix system. Flow regime 5 is the boundary dominated flow.

## 2.5 Production Data Analysis for Oil and Gas Reservoirs

Production data analysis has long been well documented in the literature. This section will review the previous work done for production data analysis including conventional and unconventional reservoirs.

#### 2.5.1 Conventional Reservoirs

Arp (Arp 1945) was one of the pioneer present the concept of decline curve analysis for conventional reservoirs. Arp said that between 0 and 1 the value of b parameter should fall into result in exponential and hyperbolic decline respectively. One limited for Arp decline curve analysis was the lack of discussion the possibility of b parameter greater than 1.

Fetkovich et al. (Fetkovich et al.1987) discussed the relationship of b parameter with the reservoir heterogeneities, but they did not include in their work the discussion the b parameter greater than 1.

Palacio and Blasingame (Palacio et al. 1993) presented the material balance time function in order to analysis gas well production data. This material time function allows for the analysis production data either constant rate or constant pressure condition. They also developed Type curves to evaluate gas in place from variable rate or variable pressure production data.

Doublet et al. (Doublet et al. 1994) applied the material balance time in the analyzing oil well production for both synthetic and field data. They concluded that this material balance time function give an excellence results for both variable rate and variable bottomhole pressure production data but they did not verified if this material balance time function also work well in linear flow.

Agarwal et al. (Agarwal et al.1999) presented new production decline Type curve for analyzing oil and gas well production data. This new production decline Type curve was combined from decline curve and Type curve analysis concept. They concluded that this new production decline Type curve presented a new tool for analyzing production data and provided an accuracy distinction between transient and boundary dominated flow period. They also said this method is only work well in analyzing production data from radial and vertically fractured oil and gas wells.

#### 2.5.2 Unconventional Reservoirs

Wattenbarger et al. (Wattenbarger et al. 1998) presented a new decline curve analysis for tight gas reservoirs. They said that in tight gas reservoir linear flow is dominated and in many wells the linear flow may last 10-20 years before the boundary effect. In these tight gas reservoirs, boundary effect may be seen but no pseudo-radial

flow. They also gave some calculations including OGIP, drainage area and the value of  $\sqrt{k} x_f$  if the boundary effect has been observed. These calculation equations were made differently between constant rate and constant pressure condition.

Helmy and Wattenbarger (Helmy et al. 1999) presented a new technique to analyze the monthly production data with multiple shut-in period and limited down-hole pressure data. They said that this new technique using superposition concept to identify an analytical model which will give the pressure response corresponded to the field. They also concluded conventional analyzing methods may not give an accuracy analyzing for wells with multiple shut-in period while this technique are a new way to do analyzing.

Mattar and Anderson (Mattar et al. 2003) provided a comprehensive comparison for all the methods available for analyzing the production data. Each method was reviewed and highlighted the strengths and limitations. They also presented a new method called Flowing Material Balance to analyze and calculate the fluid in place without requiring the shut-in pressure. They concluded that there is no single production data analysis method is capable of handling all data Types and reservoir Types.

Anderson et al. (Anderson et al. 2006) provided a guideline for analysis of production data. They also showed some challenges and common pitfalls throughout different techniques in production analysis. They concluded that the production analysis is tied to the quantity and quality of available data.

Mattar and Anderson (Mattar et al. 2005) presented a technique called Dynamic Material Balance which actually an extension of Flowing Material Balance in order to

analyze the production data. The Dynamic Material Balance can be applied to oil and gas wells to obtain the average reservoir pressure from flowing pressure without shut-in the well.

# **CHAPTER III**

# **BAKKEN SHALE HISTORY**

#### 3.1 Introduction

According to the USGS, the Bakken Shale is the largest continuous oil accumulation ever accessed in the U.S. The Bakken Shale is located in the Williston Basin. It was first discovered in 1953 (Breit et al. 1992) when the Antelope Field was discovered. The Bakken Shale play is a shale oil play and has an area of 225,000 squares miles (Price 1986). It is shared by Canada and the United States and is located in North Dakota, South Dakota, Montana, and Saskatchewan. Figure 3.1 below shows the map location of the Bakken formation.



Figure 3.1 Satellite Image Showing the Bakken Formation Location.

Most of the Bakken formation is overpressure. Bakken Shale play is said to have 300 billion barrels of oil in place (Flannery et al. 2006) as shown in Table 3.1, but there is still controversy surrounding this estimation. According to USGS, cumulative oil production from Bakken play is 190 million barrels as of August 2009. Exploration and production companies in the Bakken formation are increasing in the area because of the large oil potential within the formation. Among the top companies, based on acres leased, are Burlington Res. Oil & Gas Co. Lp, EOG Resources, Inc., and Continental Resources, Inc. (Teegue 2009). Since the formation permeability in the Bakken is very low, and oil production is mostly controlled by natural fracture, understanding the geologic characteristics of the Bakken is key for successful operating in the area.

**Table 3.1 Showing Estimated Oil in Place from Different Sources.** 

	Estimated Oil in Place				
SOURCES	(BBO)				
Dow, Williams (1974)	10				
Webster (1984)	92				
Price (1999, unpublished)	413				
Meissner & Banks(2000)	32				
Saskatchewan Industry & Resources (2005)	100				
Flannery & Kraus (2006)	300				

#### 3.2 Regional Tectonic Settings and Petroleum System

The Bakken Shale was deposited up to around 360 million years ago during the Devonian-Mississippian period. The Bakken formation consists of three parts, the upper, middle, and lower members. Both the upper and lower members were deposited in a deep anoxic marine environment while the middle member was deposited in a marine environment that was slightly disaerobic. Both the upper and lower members are rich in the total organic carbon, TOC, and can reach up to 36% while the middle member has a lower TOC, around 1%. The shale formation is believed to have a Kerogen Type 2, which is oil prone (Price 1986).

An important feature in the Bakken Shale is the Nesson Anticline, which is located in North Dakota and in which there has been little faulting and tectonic deformation. The formation has a thickness ranging from 0 to 140 feet, and it is getting thicker toward the center of the formation. The depth ranges from 9,000 to 11,500 feet (Price 1986), (Flannery et al. 2006), (Kuhlman et al. 1992). The upper and lower members act as source rock and have permeability ranging from 0.01 to 0.03 md (Price 2000) with a composition of black, pyritic, carbonaceous and fissile shale (Mageau et al.2001). They have generated oil because of their rich shale contents and high TOC, which is around 36% (Price 1986) in additional to their depth, which is around 9,000 feet and temperature, which ranges from 70 to 140°C, all of which are in oil window.

The middle member acts as the reservoir rock and contains most of the generated oil. Its thickness ranges from 10 to 92 feet and consists of complex lithology, such as sandstone, limestone and siltstones (Besler et al. 2007), with fine to very fine grain sizes

ranging in the permeability, from 0.0003 to 3.36 md. The overlaying lodgepole and the underlying "three forks" both act as a seal and result in preventing the generated oil from leaving the Bakken Shale (LeFever 2007).

The trapment of the oil was caused by the anticline and the pinch-out. There are two porosities in the middle member, primary and secondary, with an average porosity around 4% (Cox et al. 2008), and it could reach as high as 16% (Pitman et al. 2001). The secondary porosity in the middle member is generated from fractures and dolomitization. The main cementing materials are nonferroan dolospar, anhedral nonferroan, planar dolospar and calcite (Pitman et al. 2001). Dolomitization increases pore space due to replacement of calcite with dolomite, which has a smaller volume, as a main cementing material. Hydrocarbon generated in the formation resulted in over pressuring the formation, which then led to creating natural fractures (Helms et al. 2005). The interconnected fracture improved the productivity and, based on core samples, the fractures resulted in higher effective permeability (Freisatz 1990).

The middle Bakken member's mineralogy varies between clastic (30 to 60%) and carbonate (30 to 80%), with two sealing shale formations in the upper and lower zones (LeFever 2007). The carbonate rock appears to fracture more easily (Price 2000). Hydrocarbon generation also controls fracture occurrences (Helms et al. 2005). The oil presence in the Bakken Shale is related to the fractures and maturation. The shallow zone indicates immaturity and has fewer fractures. Therefore, high oil saturation and fractured formations are a result of hydrocarbon generation in the rich organic zones

(Price 2000). The natural fracture direction is north-east based on core samples (Kuhlman et al. 1992).

Despite the very low porosity and permeability value, the reservoir fluid is categorized as light oil (42 degree API) and sweet oil due to the absence of H2S (Philips et al. 2007). The viscosity value is about 0.36 cp. The initial water saturation varies between 30 and 60% (Cox et al. 2008).

#### 3.3 Field Development History

The Bakken Shale formation was discovered in 1953 in the Antelope Field. According to the HDPI public database, in 2010 the formation had a total of 2,439 active wells in the field including 16 directional, 721 undefined, 165 vertical, and 1,537 horizontal wells. These statistics may vary from source to source, but they should be close. The first horizontal well in the field was MOI #33-11, which was drilled in September 1987 by Meridian Oil Inc in Billings County, North Dakota. The well was completed with 2,603 feet horizontal displacement for 258 BOPD and 299 MCF of gas. It is now producing in the upper Bakken Shale which is 8 feet thick (LeFever 2004).

The following section will provide the brief information on the field development history of the Bakken formation, followed by a discussion of the drilling, completion, and hydraulic fracturing technologies. This information will help explain some of the production trends behavior in the area. Figures 3.2 and 3.3 below are showing the location of horizontal and vertical wells in the Bakken formation respectively:

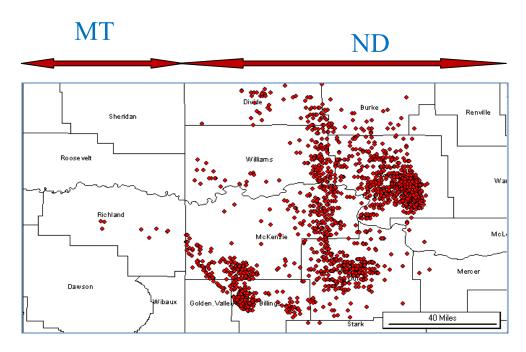


Figure 3.2 Shows the Location of 1,537 Horizontal Wells in the Area (HDPI Database).

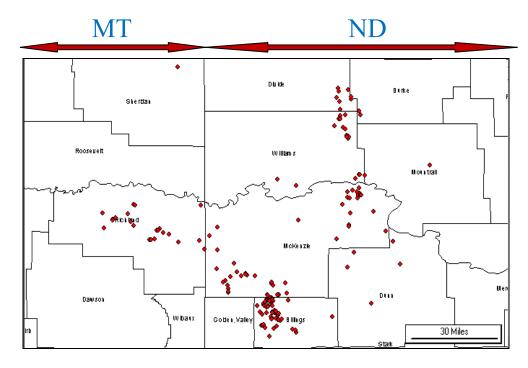


Figure 3.3 Shows 165 Vertical Well Locations in the Area (HDPI Database).

# **3.3.1 Production History**

From 1953 to 1987, oil production in the Bakken formation came from 165 vertical wells. These early vertical wells produced 11.5 million STB of oil and, 12.5 Bcf of gas accordingly to the HDPI database.

Productions from horizontal wells from 1987 until May 2010 have resulted in 131.3 million STB of oil and, 131.017 Bcf of gas, according to the HDPI database.

In the early production days, productions came from different counties, but mainly from Billings and McKenzie counties, the two oldest production counties in the area. Richland County began producing in 2005, and Mountrail County began in late 2007; they are the two new areas where the operation companies have recently tried to gain leases. Table 3.2 below shows the cumulative oil and gas production from all wells in the Bakken formation up to May 2010.

Table 3.2 Production History of the Bakken up to May 2010 (HDPI Data Base).

Well Type	Number of	Cum Oil,	Cum Gas,	
wen rype	Wells	MMSTB	Bcf	
Directional	16	0.673	0.83	
Undefined	721	97.7	74.2	
Horizontal	1,537	131.3	131.1	
Vertical	165	11.5	12.5	
Total	2,439	241.2	218.5	

Fig 3.4 shows the oil production history for Bakken Shale-North Dakota from 1951 up until June 2010.

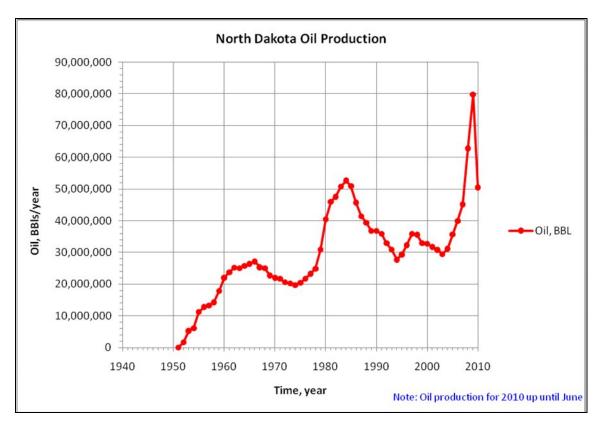


Figure 3.4 Oil Production History-North Dakota (Helms, L.D. et al. 2008).

# 3.3.2 Drilling and Completion Technologies

Though oil was discovered in the Bakken Shale formation in 1953, production activities have only been aggressively active since early 1990, when the horizontal well technology began to be applied in the industry. The horizontal well technology was divided into two periods: early and late. Early horizontal well productions took place from 1987 to the early 2,000s. This early horizontal well technology had the ability to

drill a well approximately 1,000 feet long (Flores 2008). Late horizontal well productions began in the mid 2000s and continue today. They are a big improvement in the industry's technology for unconventional reservoirs, which have helped to produce a higher production rate. The second period of the horizontal well technology has helped the operation companies by creating the ability to drill longer horizontal lateral ranges from 3,000 to 4,000 feet (Cox et al. 2008), and multilateral wells. Figure 3.5 shows the number of horizontal wells in the area.

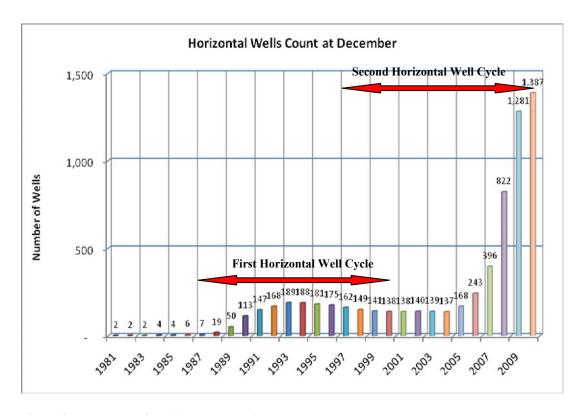


Figure 3.5 Numbers of Horizontal Wells in The Bakken (HDPI Database).

In additional, completion technologies helped with increasing the production rate during the second cycle of horizontal wells. Early completion technology was applied by using cementing wellbore completion. This technology was designed to allow more control of fracture initiation location along the wellbore. There were some issues with this technique, including excessive pressure losses and, formation damage due to perforating through casing and cementing. These issues created a higher cost because of the requirement to acidize in order to clean up the wellbore damages (Beau et al. 2008).

Today completion technology uses a technique called open-hole completion, which utilizes an open-hole packer for mechanical diversion (Kuuskraa 2009). This technology was first applied to the Barnett Shale formation, and it proved to be a successful improvement in hydraulic fracturing performance. Therefore, operation companies applied this technology to the Bakken Shale formation.

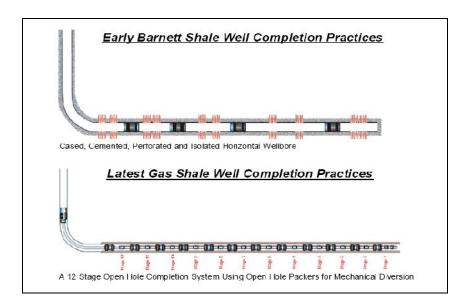


Figure 3.6 Completion Technologies Which Applied to Bakken Shale Formation (Kuuskraa 2009).

Stage diversion was another issue that made it difficult for the horizontal wells to be fractured to the entire wellbore. The longer the horizontal wells lateral, the greater the heel-to-toe pressure drop due to friction. The first technology used degradable ball sealers to plug the perforation of the previously fractured zone. The problem associated with this technology was the fracture fluid tended to go to the zone that had already been fractured. To solve this problem, the service companies needed to pump an extra amount of fracture fluid, which cost more than the actual requirement. The newer technology was introduced by using swelled packers and ball actuated sliding sleeves as shown in Figures 3.7 and 3.8.

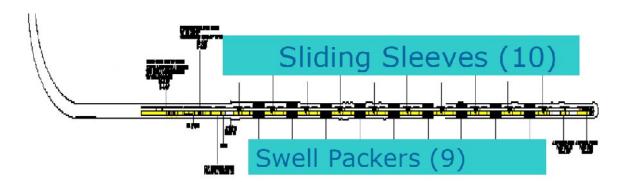


Figure 3.7 Ball Actuated- Sliding Sleeves Completion Technology (Peneitz et al. 2008).

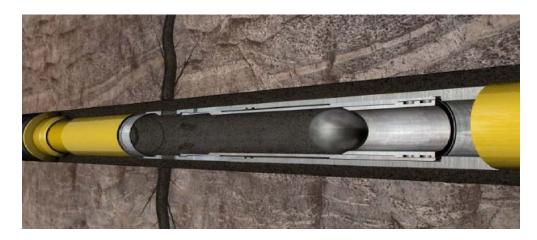


Figure 3.8 Ball Actuated (Peneitz et al. 2008).

The ball actuated sliding sleeves technique was designed to isolate the fracture zones completely. This technique prevents the fracture fluid from going into the already fractured zone and helps to fracture the current zone effectively. The disadvantage of this technique is that it limits the number of fractures to 10, as can be seen in Figure. 3.7, but it is still widely used in the field today.

Swell packers help to isolate the annulus zone so that the fracture fluid does not go into the already fractured zone inside the annulus. Fracture fluid goes straight to the current fracture zone and helps to break the formation effectively.

The benefit of these two technologies is that they create a positive fracture stage diversion. They simplify the multistage fracture jobs and ensure the entire horizontal well lateral be stimulated (Peneitz et al. 2008).

# 3.3.3 Hydraulic Fracture Technologies

Hydraulic technologies have also helped improved the production rate in the Bakken Shale. There are many factors that can cause the success of the hydraulic fracturing performance. The main factor is the fracturing fluid.

Initially fracturing used gel as the fluid to carry a proppant down to break the formation. The initial amount of fluid and proppant was estimated at approximately 300,000 gals of fluid and 300,000 lbs of proppant (Ayers 2008). By the early 90's the amount of fluid and proppant had increased slightly to 1,000,000 gals of fluid and 1,000,000 lbs of proppant to help create a longer and larger fracture system. More effective hydraulic fracturing started in early 97's. This technology known as "slick water" fracturing was first used in Cotton Valley and Barnett Shale (Ayers 2008). Slick water fracturing involves adding some chemicals to reduce the viscosity of water in order to penetrate deeper to create a longer fracture and carry the proppant down farther to the fracture. This new technology reduces the cost by 30-70% (Ayers 2008), which in turn makes the shale formation wells economical to the operation companies.

Table 3.3 and Table 3.4 below show some examples of wells from the old technology compare to advanced modern wells. Wells in the group of the advanced modern wells show a significant improvement in the cumulative oil production compared to those of the old technology groups.

Table 3.3 Group of the Old Technology Cycle.

Wells Name	Start	Initial Oil Rate, STB/Month	Report Date	Cum_Oil Until Report Date, STB
ANNA 1-3H	10/1/2005	2643	7/1/2009	133190
BROWN 1-6H	6/1/2004	5125	7/1/2009	133108
BROWN 1A-6H	6/1/2004	4772	7/1/2009	77817
BURLINGTON 1-25H	9/1/2004	6939	7/1/2009	219841
CAROLINE 1-32H	12/1/2004	1732	7/1/2009	58325

**Table 3.4 Group of Advanced Modern Cycle.** 

Wells Name	Start	Initial Oil Rate, STB/Month	Report Date	Cum_Oil Until Report Date,STB
AUSTIN 2-03H	11/1/2007	39114	8/1/2009	358835
AUSTIN 4-09H	12/1/2007	23726	8/1/2009	367258
BARTELSON 1-3H	11/1/2006	14202	8/1/2009	308733
C & B 1-31H	5/1/2007	18414	8/1/2009	247470
CHRISTIE 1-22H	3/1/2008	24177	8/1/2009	231507

After 5 years of production, the first groups of old technology wells had a cumulative oil production less than the second groups' production after only 2 years as shown in Table 3.3 and Table 3.4.

# 3.3.4 Crude Oil Transportation

Crude oil transportation is one of the factors that can affect and hinder the production rate in the Bakken formation. Due to the fast development and production rate in the Bakken area, in 2006 the pipeline could not handle the increasing amount of crude oil production. The pipeline capacity was 15,000 bbls per day in 2006. This is less than the crude oil transportation demand of 21,000 bbls per day (Grape 2006).

In the first quarter of 2009, EOG Resources had to ship some of its oil production by truck. The cost of the transportation is \$22 per barrel, so the company decided to restrict production from its wells because of the cost of crude oil transportation (Eric 2009).

Some solutions presented to solve the transportation issue in the Bakken area included a new pipeline projects called the Enbridge pipeline expansion to increase capacity and a railroad train project, which from EOG, to help reduce the cost of crude oil transportation.

One of the Enbridge pipeline expansion projects is called the Cochin Bakken Project and was proposed by Kinder Morgan Cochin LLC in North Dakota in April 2009. This project proposed modifying the existing pipeline in North Dakota to transport crude oil to the distant markets and was available by June 2009. The project pipelines covers approximately 1,900 miles and originate in Fort Saskatchewan. Its capacity of

crude oil transportation is approximately 30,000 bbls per day (Dan 2009). Figure 3.9 below shows the project map proposed by Kinder Morgan Cochin LLC.

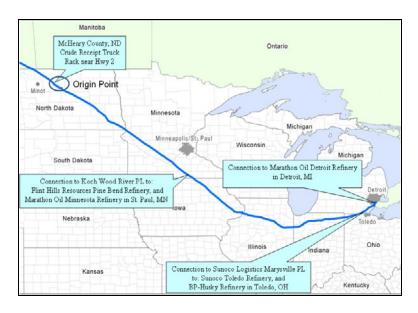


Figure 3.9 Shows the Project Map of Pipeline from ND to MT  $^{(Dan\ 2009)}$ .

Transportation crude oil by train was another solution for the pipeline limited capacity problem. EOG Resources one of the pioneers in the area built their own railroad and trains for crude oil transportation. On December 31, 2009, EOG's first train departed from Stanley, North Dakota headed for Stroud Oklahoma. The capacity for transportation crude oil per train is approximately 60,000 bbls (VanBecelaere 2010). With its own transportation system EOG has maximized its production rate in the Bakken Shale formation and become one of the largest producers in the area. Figure 3.10 below is showing EOG Tank Cars being unloaded at Stroud.



Figure 3.10 EOG Tank Cars being Unloaded at Stroud (VanBecelaere 2010).

# 3.4 Chapter Summary

In summary, the oil production in the Bakken formation is affected by several factors including drilling technologies, completion technologies, and hydraulic fracture technologies, as well as pipeline capacity and crude oil transportation issues in the area. Each factor is important in the future contributions of the Bakken oil-bearing shale.

# **CHAPTER IV**

#### WELL PRODUCTION TRENDS

#### 4.1 Introduction

The initial production data are available for 146 wells in 8 counties, mostly from Billings County and McKenzie County, of different companies. Most of these production data come from HDPI database, in the format of monthly production rate for oil, water and gas. The criterion for choosing production data from HDPI data base is that the wells have to have at least 10 years of production history in order to perform the analysis.

Unfortunately, these production data do not have the information for the completion, PVT or pressure data. An additional 95 well data including daily production rate, completion, PVT, pressure data are given from companies who sponsor for this research study.

This chapter will analyze production data well by well. and classify them into categories, which are referred to production Type I, Type II and Type III. Each of production Types will give some field examples, and the reservoir mechanism of each Type will be explained. A simple reservoir simulation will be set up to confirm the observation and explanation.

**Table 4.1 Production Trend Types Summary.** 

Table of summary								
County	Wells							
	Type I	Type II	Type III					
Billings	36	11	14					
Burke		1	1					
Divide	1	1	1					
Dunn	1	3	4					
Golden Valley	1	4	1					
McKenzie	35	19	6					
Richland		1						
Williams	1	2	2					
Total	75	42	29					
%	51%	29%	20%					

Table 4.1 above shows the number of wells in each of the production Type from different counties. The other 95 wells from private companies have production rate in the format of daily production rate. It is hard to classify them into production trend Types because they have only 3 years of production period. In additional, the company has tried to install pumping unit on all of them in order to keep the production rate high. This may affect the studying analysis for the well and reservoir behavior.

#### 4.2 Data Management

In order to save time in handling and analyzing of 251 wells (146 wells from HDPI data base, 95 wells from private companies), a VBA excel program had developed to manage the data.

# 4.2.1 Data Types

Two Types of data were providing for the analysis. Following are the Types of data provided for 146 wells from HDPI data base:

- 1. Oil production rates (STB/ month).
- 2. Water production rates (STB/ month).
- 3. Gas production rates (Mscf/month).

Other Types of data were provided for 95 wells from the private companies:

- 1. Oil production rates (STB/ day).
- 2. Water production rates (STB/day).
- 3. Gas production rates (Mscf/day).
- 4. PVT data including: Rs, Bo, Bg, Co, Cg, etc.
- 5. Pressure data including flowing tubing pressure, and flowing casing pressure.
- 6. Reservoir properties including: Pi, GOR, Temperature, Gas gravity, API, etc.
- 7. Completion data including: Well bore schematics, perforation reports, fracture reports, pump installation reports, etc.

# 4.2.2 Excel VBA Program

The VBA excel program has the ability of plotting diagnostic plots and handling some calculations.

Following are Types of calculation which VBA program can perform:

- 1. Flowing bottom hole pressure,  $p_{\rm wf}$ , This is calculated from flowing tubing pressure .Begg and Brill method was using to make the  $p_{\rm wf}$  calculation.
- 2. Material Balance Time which defined as  $Q_o/q_o$ .
- 3. Superposition Times with respect to t,  $\sqrt{t}$ , log (t).
- 4.  $(pi p_{wf})/q_o, q_o/(pi-p_{wf}).$
- 5. Cumulative Oil, Cumulative Gas, GOR, Cumulative GOR.

Figure 4.1 below shows the VBA calculation generated window.

Date		Car sime desire	OI DD	Con Mark	Mara Di	CTD	OD and	Comp. Cit.		COD Man	Con ES Em March	5 4 4-1 -0-W	Contract	O COT	
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	4/11/2007	0	0	0		0									
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	4/13/2007	0	0			0									
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	4/18/2007	0	0			0		0							
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Figure 4.1 VBA Program Calculation Generated Window.

Following are Types of diagnostic plot which the VBA program can plot:

- 1. Decline curve semi-log of log (qo) vs. time.
- 2. Log-log plot of rate vs. time.

- 3. Plot of qo vs. Cumulative Oil plot.
- 4. Plot of  $q_0/(pi-p_{wf})$  vs. Cumulative Oil plot.
- 5. Specialized plot of (pi-pwf)/qo vs.  $\sqrt{t}$ .
- 6. Specialized plot of (pi-pwf)/qo vs. Superposition time with respect to  $\sqrt{t}$ .
- 7. Plot of tubing pressure,  $p_{wf}$ , and Cumulative GOR vs. Cumulative Oil.

Figure 4.2 below is showing the VBA plot generated window.

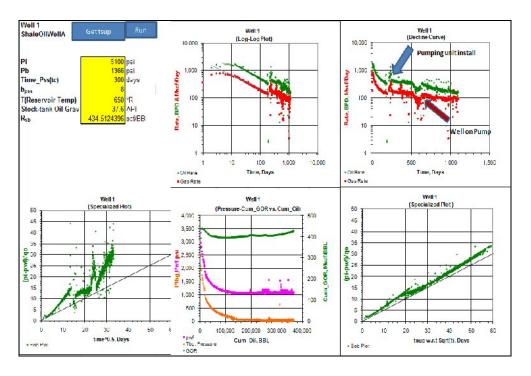


Figure 4.2 VBA Program Plot Generated Window.

#### 4.2.3 Steps in Using Excel VBA

1. Copy and Paste the original data in to the worksheet "Data".

- 2. Put the first day of oil production into "FirstDay" box in the worksheet "Analysis".
- 3. Input reservoir data such as Pi, T, P<sub>b</sub>, etc, into yellow box in the worksheet "Analysis".
- 4. Press button called "Run" to generate the calculations and plots. This step may take few minutes if the data more than 1000 data.
- 5. When all the diagnostic plots have been generated, press button called "Gettsup" to calculate the Superposition times with respect to t,  $\sqrt{t}$ , and  $\log$  (t). Plots of these superposition times will automatically generate.

By the end of this section all the necessarily calculations and diagnostic plots will be available for the study analysis in the next section. Also by using these diagnostic plots, Types of production trend are classified and put in each category.

#### **4.3 Production Trend Types**

This section analyzes the production data base on production trend Types I, II, III, which have been classified from previous section .Explanations for the reservoir mechanism of these production trends will be provided. Simple reservoir simulation model to confirm the explanation will also be provided.

# **4.3.1 Type I Production Trends**

During the observation of the production data for 146 wells, on the semi-log plot of rate vs. time plot, Type I production decline can be defined as having the gas releases after a period of production time. There are also three categories in the Type I production trend:

• Category A shows rapid decline initially then changes to a steady and slow decline as shown in Figure 4.3

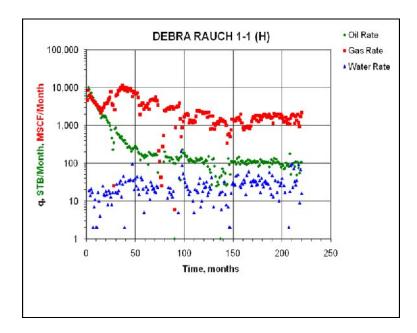


Figure 4.3 Type I Production Trend Category A.

• Category B shows a short rapid decline initially then changes to a steady and slow declines as shown in Figure 4.4

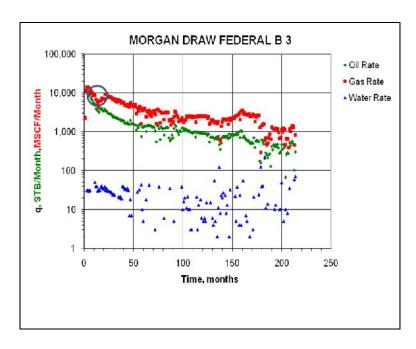


Figure 4.4 Type I Production Trend Category B.

• Category C shows a long rapid decline but does not change the slope of the curve later as shown in Figure 4.5

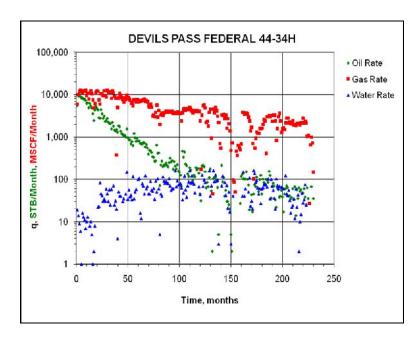


Figure 4.5 Type I Production Trend Category C.

Category A and B has two semi log straight lines. The first semi log straight line is when the well produces from the fracture network, while the second semi log straight line is from the matrix supporting. Category A has more fracture flow than matrix flow, while Category B has more matrix flow than fracture flow. Category C does not have the second semi log straight line. This is because it is only producing from the fracture network only, and there is no matrix supporting in the end.

In the total of 146 wells data, there are 51 % of wells in Type I production trend. This high percentage of Type I production trend is showing the true characteristic of the Bakken Shale reservoir, which has complex natural fracture network in the formation.

# 4.3.1.1 Reservoir Mechanism of Type I Trends

This section will describe the reservoir mechanism for each category of the Type I production trend,

• Category A of Type I production Trend (More fracture flow than matrix flow): In order to describe the reservoir mechanism, two plots including semi log plot of rate vs. time and log-log plot of rate vs. time are given as Figure 4.6 and Figure 4.7 respectively below.

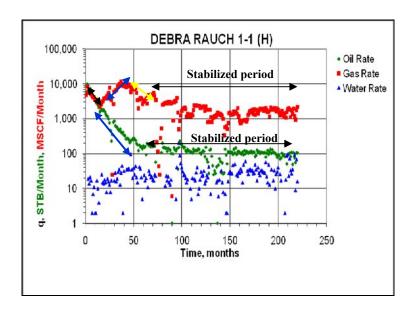


Figure 4.6. Semi log Plot of Category A.

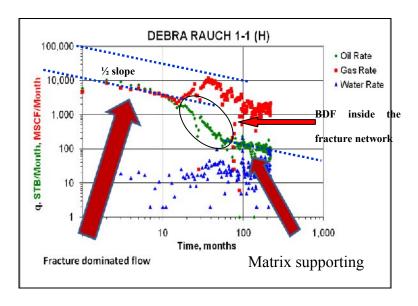


Figure 4.7 Log-Log Plot of Rate vs. Time, Category A.

The reservoir mechanism for category A of production trend Type I can be described as:

- 1. Initially single phase oil flows linearly from the fracture network into the well. Reservoir pressure at this point is still above the bubble point pressure. These behaviors can be seen on the semi log straight line as the black line and on the log-log as the first ½ slope straight line. Notice that the time for this period on the two plots, is corresponding. It is about 15 months.
- 2. Oil will continue to flow inside the fracture network until the pressure drop reaches the end of fracture network, BDF, inside the fracture network. At this time the reservoir pressure is dropping below the bubble point pressure and gas starts releasing out of solution. Oil still flows from fracture network into the well but it is not linear flow. This can be seen on the log-log plot when the blue line is

deviated from ½ slope curve, indicating pressure drop reaches the end of fracture network. Gas releases out of solution, and it can be seen as blue line on the semi log plot of gas decline curve. Oil production rate continue to drop fast as seen by the blue line on the semi log plot of oil rate decline curve.

- 3. The matrix starts to drain to the fracture network. resulting in the decreasing of gas production. This behavior can be seen from the yellow line on the semi log plot of gas production rate decline curve. The first time when the matrix drains into the fracture network, it does not provide enough pressure supporting, resulted in the oil production rate still drop fast.
- 4. When the supporting from the matrix is strong enough, both the oil and gas production rate will be stabilized. This behavior can be seen as the two black lines on the semi log plot. Also second ½ slope line appears again on the log-log plot. This stabilized period also can be seen on the GOR as shown in Figure 4.8 below.

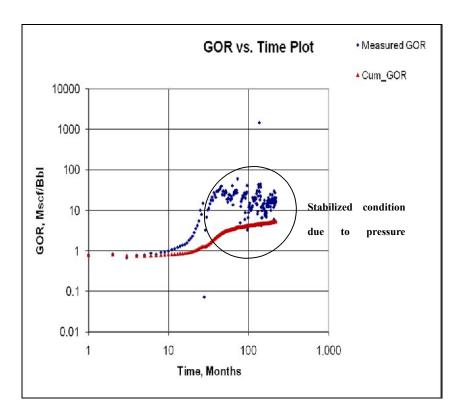


Figure 4.8 GOR Decreasing When Stabilized Condition Starts.

More field case examples for the reservoir mechanism of category A production

Type I trend are given in the Research Group Report.

Category B of Type I production trend (Fracture flow with strong matrix supporting): Semi log plot of rate vs. time, and log-log plot of rate vs. time for the category B of Type I production trend are given as Figure. 4.9 and Figure.
 4.10 respectively below:

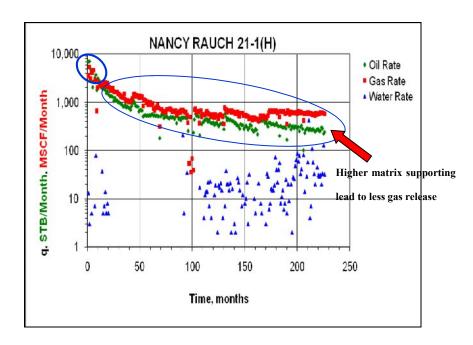


Figure 4.9 Semi Log Plot of Category B Production.

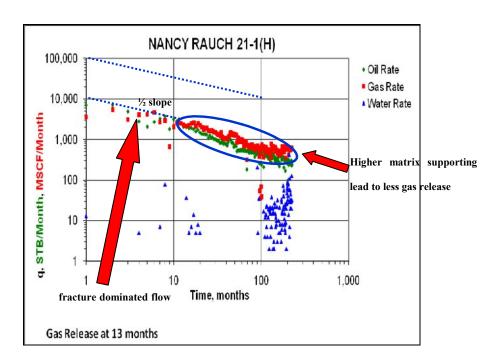


Figure 4.10 Log-Log Plot of Category B Production.

The reservoir mechanism for category B of production trend Type I can be described as:

- 1. Initially the well producing oil linearly from the fracture to the well. Reservoir pressure at this point is still above the bubble point pressure. This can be seen as first blue eclipse shape on the semi log plot and first ½ slope on the log-log plot.
- 2. When the pressure drop inside the fracture network reaches the end, the matrix starts draining into the fracture network, resulting from decreasing in gas production rate. This period of high matrix supporting stays longer in the reservoir, resulting from the gas producing together with its associated oil. This can be seen as second blue eclipse shape on the semi log plot and on the log-log plot. This strong matrix supporting can also be seen on the GOR plot as shown in Figure 4.11 below.

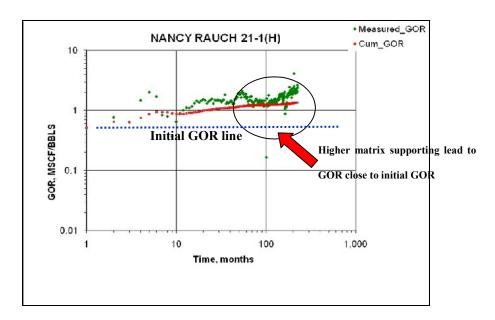


Figure 4.11 GOR is Close to the Initial GOR for Category B.

More field case examples for the reservoir mechanism of category B production

Type I trend are given in the Research Group Report.

• Category C of Type I production trend (Fracture flow only): Semi log plot of rate vs. time and log-log plot of rate vs. time for the category C of Type I production trend are given as Figure 4.12 and Figure 4.13 respectively below:

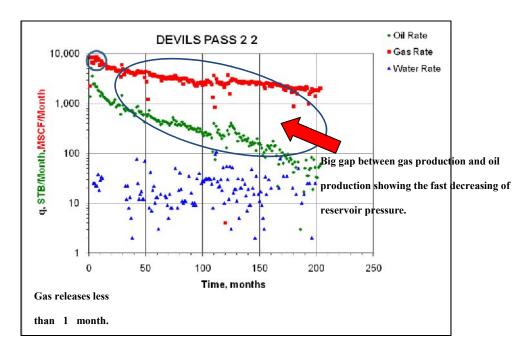


Figure 4.12 Semi Log Plot of Category C Production.

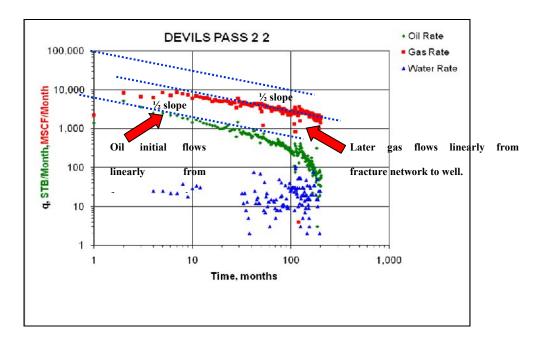


Figure 4.13 Log-Log Plot of Category C Production.

The reservoir mechanism for category C of production trend Type I can be described as:

- Oil linearly flows from fracture network to the well. Gas releases quickly less
  than one month because of fast production from dense fracture network. Gas
  does not flow yet at this time since it does not reach the critical saturation to
  flow.
- 2. Oil continues to flow inside the fracture network to the well until the pressure drop reaches the end of fracture inside the fracture network. This can be seen on the log-log plot when the oil rate deviated from ½ slope around 5 months.
- 3. Reservoir pressure continues to drop faster after reaching the end of fracture network. There is no matrix supporting at this time so oil rate continues to drop faster. This can be seen on the semi log plot with the stiff slope of oil rate. It does

not change the slope later as category A, and B because there is no supporting in the matrix. GOR will not show the stabilized condition in this category C production as shown in Figure 4.14.

4. Gas reaches critical saturation and flows linearly from the fracture network into the well. This happen slower than oil flows because gas is compressible. This can be seen on the ½ slope of the log- log plot of gas production curve.

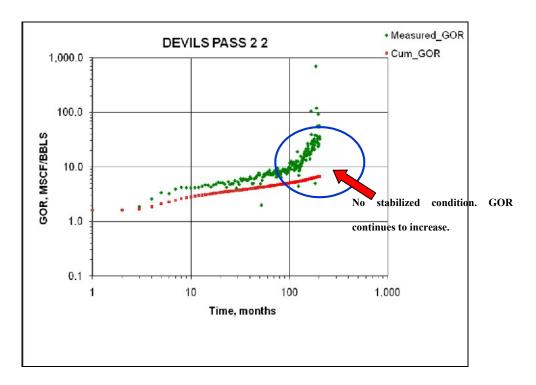


Figure 4.14 No Stabilized Condition for GOR.

More field case examples for the reservoir mechanism of production Type I trend category C are given in the Research Group Report.

## 4.3.1.2 Simulation Models of Type I Trend

This section will present a simple CMG simulation model to represent the production behavior for the Type I category A. The category B, C production Type simulation models will make as recommendation for future works.

The reservoir illustration for Category A production is given as Figure 4.15 below:

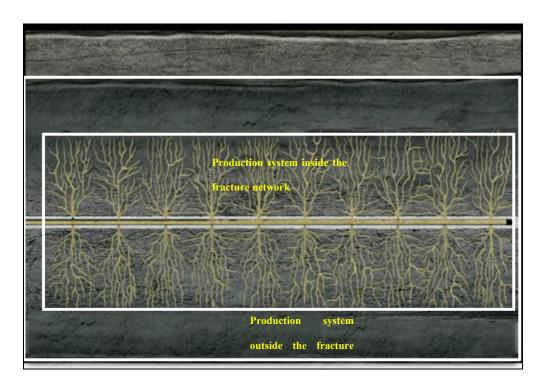


Figure 4.15 Reservoir Illustration for Category A Production.

Two production systems are seen in the Figure 4.15 above:

- 1. Production system inside the fracture network.
- 2. Production outside the fracture network-The matrix.

This reservoir illustration can be described together with the production Type I category A. Initially the well will produce oil from the fracture network because of high permeability. Later the production inside this fracture network is reaching the end of fracture with the reservoir pressure drop continuously. Reservoir pressure will drop below the bubble point pressure. At this point gas releases result in gas production rate increasing, oil production continues to drop fast. At some point the matrix starts draining into the fracture network giving the pressure supporting. This will result in gas production decreasing, and gas production rate will be stabilized later. Oil production rate also will be stabilized at the same time.

After describe the reservoir behavior of reservoir illustration above, simulation model will be constructed to matching the production Type of category A. Figure 4.16 below shows the reservoir model for category A production.

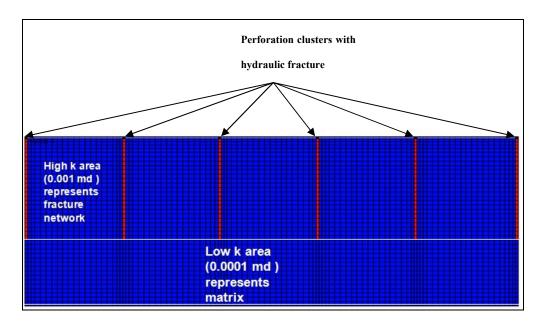


Figure 4.16 Simulation Model for Category A Production.

The simulation will be run for two different times: 20 years and 50 years to see the different behavior for two periods. Following are the simulation results for category A production Type:

• Results for 20 year of simulation production:

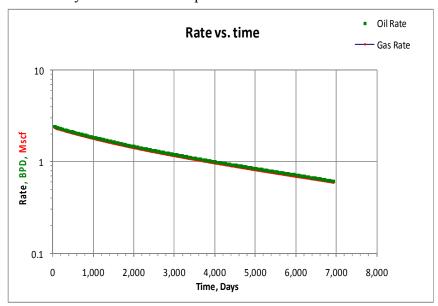


Figure 4.17 Semi Log Plot Rate vs. Time Simulation Results for Category A Production.

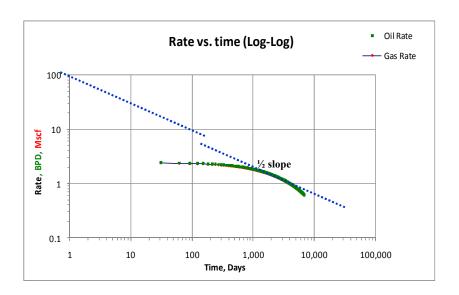


Figure 4.18 Log-Log Plot Rates vs. Time Simulation Results for Category A Production.

By the end of 20 year simulation run, oil and gas still flow together from fracture network to the well and the pressure drop is about to reach the end of fracture network. This can be seen on the semi log plot with oil and gas rate overlap each other, and on the log-log plot the oil and gas rate have ½ slope. GOR is almost constant as shown in Figure 4.19 below.

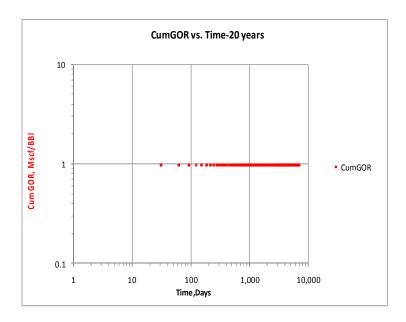


Figure 4.19 GOR Simulation Results for Category A Production.

• Results for 50 years of simulation production:

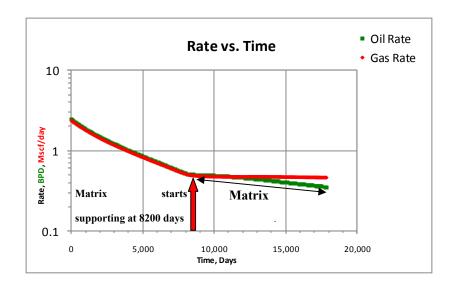


Figure 4.20 Semi Log Plot Rate vs. Time Simulation Results for Category A Production.

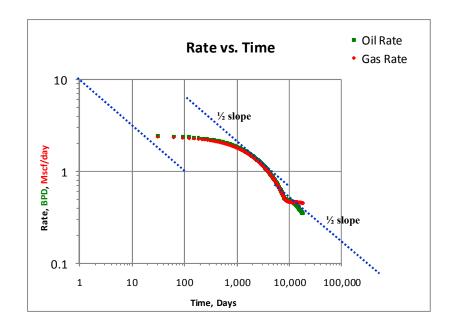


Figure 4.21 Log-Log Plot rates vs. time Simulation Results for Category A Production.

The simulation continued to run until 50 years of production. This time the matrix starts to drain into the fracture network system providing pressure supporting. As seen on the Figure 4.20, the oil rate changes the slope of the curve indicating the matrix supporting at 8200 days. Also on the log-log plot Figure 4.21, second ½ slope appears indicating the matrix starts draining into the fracture system before it reaches the BDF in the matrix.

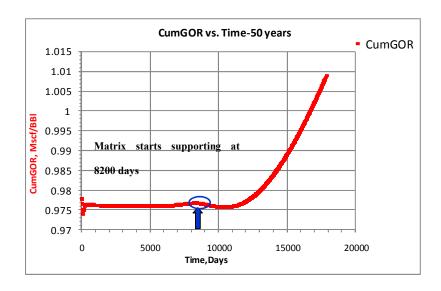


Figure 4.22 GOR Simulation Results for Category A Production.

Stabilized condition can be seen also on Figure 4.22 when the GOR starts decreasing at the same time 8200 days. Later GOR will increase indicate the matrix reaches BDF.

### **4.3.2** Type II Production Trend

On the semi-log plot of rate vs. time plot, Type II production decline can be define as not having the gas release after a period of production. Figure 4.23 below shows the semi log plot production curve of Type II production decline.

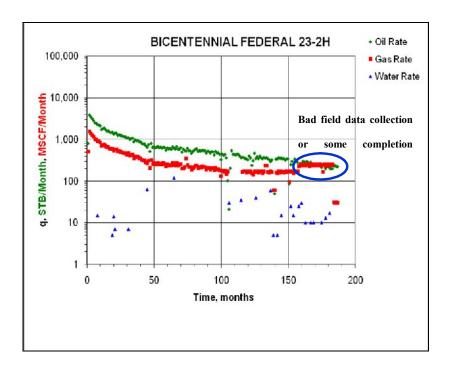


Figure 4.23 Semi Log Plot of Type II Production.

# 4.3.2.1 Reservoir Mechanism of Type II Trend (Matrix only)

Type II production shows a single exponential decline on semi log plot. Gas does not release, and there is short period of increasing gas at the end but this is scattering field data collection or some workovers which the company try to increase production. Oil and gas are produced together for the entire of production life. The drive mechanism for the Type II is oil expansion drive and producing from matrix only. This can be seen clearly on the log-log plot Figure 4.24 below.

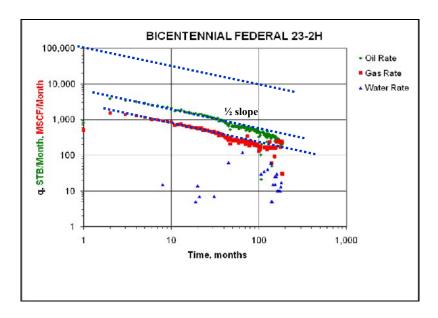


Figure 4.24 Log-Log Plot of Type II Production.

Figure 4.24 shows oil and gas linearly flow from the matrix into hydraulic fracture or well. After 40 months, the flow reaches BDF. The reservoir under Type II production is not economic for producing since there is no energy supporting when the flow reach BDF. GOR of this well shows constant for the entire of production life except the last few months of some scattering field data collections or some workovers which the companies try to increase production which is shown in the Figure 4.25 below. Most of the Type II production exhibits the same gas increasing behavior at the end of data and it is shown in Research Group Report.

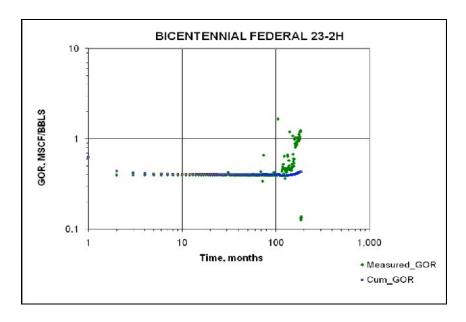


Figure 4.25 GOR of Type II Production.

# 4.3.2.2 Simulation Models of Type II Trend

The reservoir illustration for simulation Type II case is shown in Figure 4.26 below:

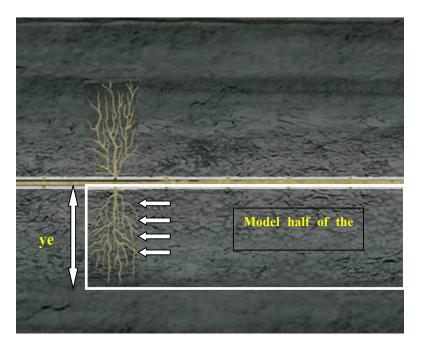


Figure 4.26 Reservoir Illustration for Type II Production.

Instead of having multiple fracture networks with closed spacing like category A production, Type II production has fracture network spacing far way each other leaving large matrix area between them as shown in Figure 4.26. This reservoir illustration will make sure the production mainly from the matrix. Simulation model for this illustration is given as Figure 4.27 below.

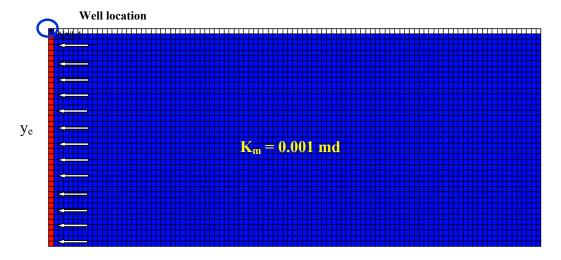


Figure 4.27 Simulation Model for Type II Production.

The simulation will be run for two different times: 20 years and 50 years to see the different behavior for two periods. Following are the simulation results for Type II production Type:

• Results for 20 years of simulation production:

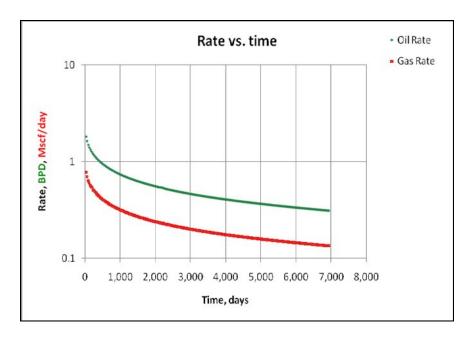


Figure 4.28 Semi Log Plot Simulation Result 20 Years for Type II.

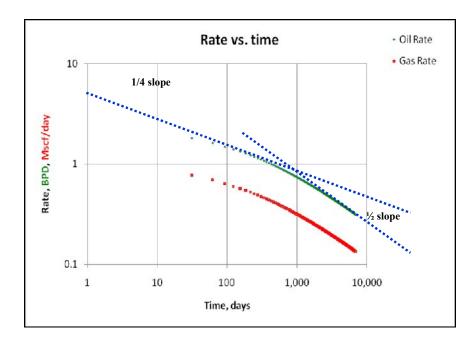


Figure 4.29 Log-Log Plot Simulation Result 20 Years for Type II.

As shown in Figure 4.28, oil is produced as single phase for 20 years without gas releasing. On the log-log plot of rate vs. time, Figure. 4.29 shows oil linearly flows from the matrix to fracture at later time. ¼ slope appears in early time because of the fracture half length is extended long enough to create bilinear flow. Field data did not show the ¼ slope indicated the fracture does not extend long enough to create the bilinear flow. This simulation results confirm the matrix is the dominated flow in the Type II production. GOR plot in Figure 4.30 is constant for the entire 20 year simulation run.

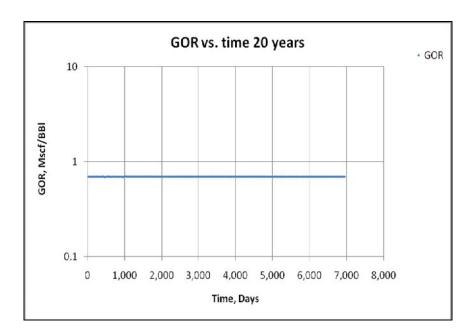


Figure 4.30 GOR Simulation Result 20 Years for Type II.

• Results for 50 years of simulation production:

The simulation continued to run until 50 years of production. This time the matrix is still the dominated flow with oil linearly flows into the fracture. As seen on the Figure 4.31, the gas rate is low than oil rate indicated that this is the solution gas production not

the free gas release out of solution. Also on the log-log plot Figure 4.31, ½ slope appears later indicating oil flow linearly from the matrix into the fracture before it reaches the BDF at the end. Also early ¼ slope on the Figure 4.32 is indicating bilinear flow at beginning.

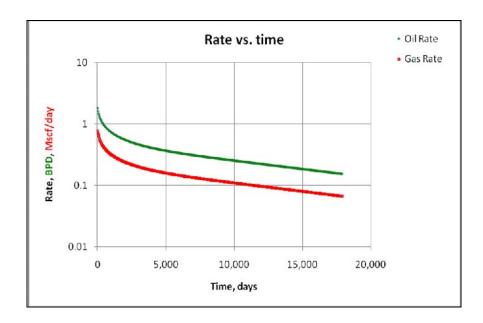


Figure 4.31 Semi Log Plot Simulation Result 50 Years for Type II.

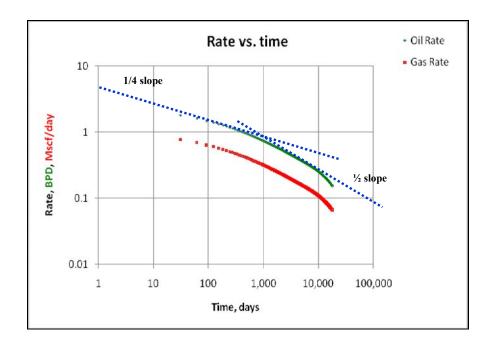


Figure 4.32 Log-Log Plot Simulation Result 50 Years for Type II.

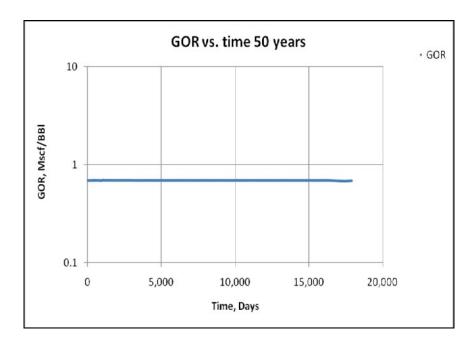


Figure 4.33 GOR Plot Simulation Result 50 Years for Type II.

GOR is almost constant for 50 years of simulation run time.

## 4.3.3 Type III Production Trend

Type III production trend typically has scattering production data from wells with a different Types of trend. It is difficult to study this Type of behavior because of scattering data and it will lead to bad interpretation for the analysis. The semi log plot of Type III production is shown below in Figure 4.34.

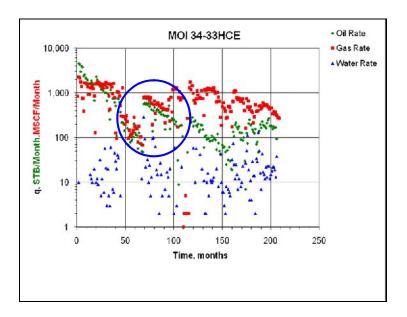


Figure 4.34 Semi Log Plot of Type III Production.

As shown in Figure 4.34 the well production rate exhibit rapid decline at beginning. This behavior is similar to Type I category A production when the production occurs within the fracture network system. Later it is looked like the company try to install lift system or shut in the well to increasing the production rate, but it is not

effective. The rate continues to drop fast. Several shut in periods performed later making the curve difficult to analyze. Figure 4.35 below shows the log –log plot.

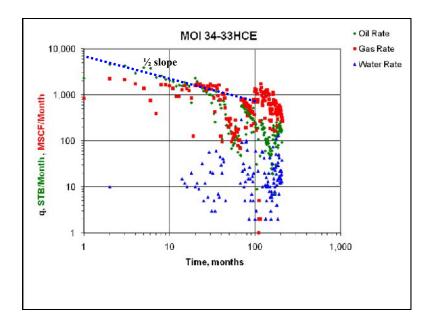


Figure 4.35 Log-Log Plot Type III Production.

Another example of Type III is given as Figure 4.36 and Figure 4.37. This well behavior is similar to the previous one with rapid decline at beginning. Later some water injection was performed to increase the production but it is not effective. All Types III production has the same production behavior as shown in these figures with some interference from the operation company.

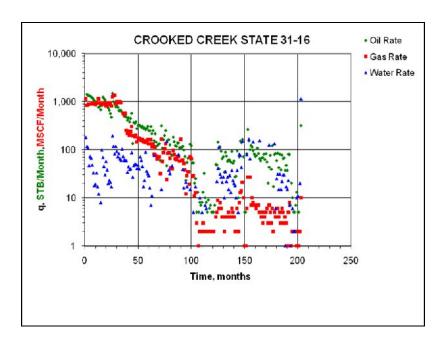


Figure 4.36 Semi Log Plot of Type III Production.

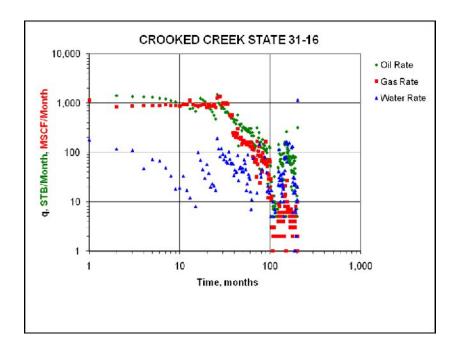


Figure 4.37 Log-Log Plot of Type III Production.

## 4.4 Chapter Summary

In summary there are two Types of well production trend in the Bakken Shale. Type I is production trend associated with the reservoir pressure drops below bubble point pressure and releases gas. There are three category production Types of Type I namely A, B, C exhibit these gas releasing behavior:

- Type I category A: the flow in this category has fracture dominated flow with a weak to mediated matrix supporting.
- Type I category B: the flow in this category has strong matrix supporting resulting in gas is producing with it associated oil.
- Type I category C: This is the fracture dominated flow only without matrix supporting.

It is better to have extensive fractures systems and supporting by matrix porosity, the well production is more economically attractive.

Type II production does not have fracture dominated flow only matrix flow resulting in lower oil recovery than Type I production.

## **CHAPTER V**

### **FLOW REGIMES ANALYSIS**

#### 5.1 Introduction

This chapter analyzes the production data to identify the flow regimes. The work focuses on analyze flow regimes to identify when the boundary dominate flow is begin. After the boundary dominated flow is identified, several decline curve analysis will apply to calculate the OOIP.

## **5.2 Flow Regimes Analysis Using Diagnostic Plots**

Analyzing flow regimes is a very important step for reservoir engineers because each flow regimes carry different information about the reservoir behavior. For example, ½ slope indicates the fluid linearly flow from one location to another: fracture to well, natural fracture to hydraulic fracture, etc. Many diagnostic plots are used to identify the flow regimes. Log-log plot of rate vs. producing time is one of the basic plots used to identify the flow regimes. Figure 5.1 is an example of log-log plot, which shows ½ slope indicating linear flow.

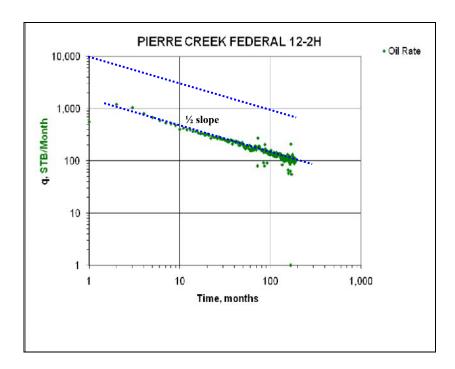


Figure 5.1 Log-Log Plot Shows Half Slope Indicating Linear Flow.

It is better to use other diagnostic plots together with log-log plot to identify the flow regime more accuracy. Specialized plot of (pi-pwf)/q vs.  $\sqrt{t}$  or (pi-pwf) vs.  $\sqrt[4]{t}$  are use together along with log-log plot to identify linear flow and bilinear flow respectively. Figure 5.2 below is an example of specialized plot of (pi-pwf)/q vs.  $\sqrt{t}$ . It shows the reservoir is in linear flow at the early time then reaches the boundary dominated flow, BDF, at  $11^{th}$  month.

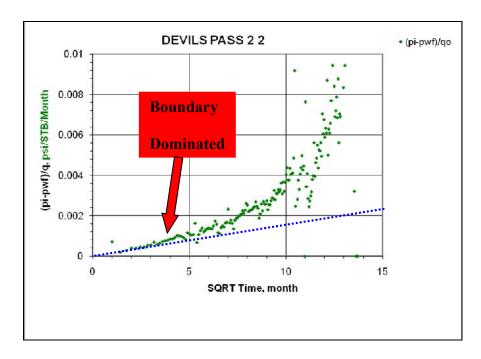


Figure 5.2 Specialized Plot Shows Reservoir is Linear Flow then Reaches BDF.

### 5.2.1 Review Data Availability for Analyzing Flow Regimes

The initial production data are available for 146 wells in 8 counties, mostly from Billings County and McKenzie County, of different companies. Most of these production data come from HDPI database, in the format of monthly production rate for oil, water and gas. The criterion for choosing production data from HDPI data base is that the wells have to have at least 10 years of production history in order to perform the analysis.

Out of the 146 wells provided, there were 117 wells having good data for analyzing flow regimes, and these are in Type I, Type II production group. Figure 5.3 is one of example for good data well.

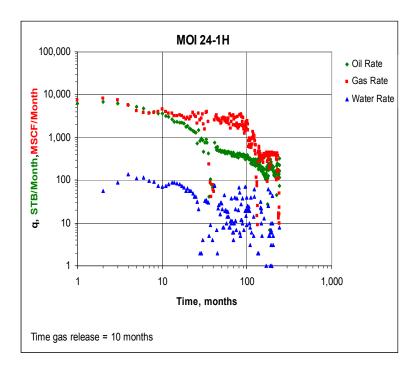


Figure 5.3 Shows Example of Good Data for Analyzing.

The well example above has 205 months of production data available. It is almost 20 years of production data. This well shows low rates of scattering or fluctuating production data, because of multiple shut-in intervals or being affected by pumping unit. It is easier to analyze the well data like this because the reservoir information can be recognized or identified.

An additional 95 well data including daily production rate, completion, PVT, pressure data are given from companies who sponsor for this research study. It is hard to perform the flow regime analyzing for these 95 well production data. The company has tried to install pumping unit on most of them in order to keep the production rate high. This may affect the studying analysis for the well and reservoir behavior. Figure 5.4 is one of the examples for this group.

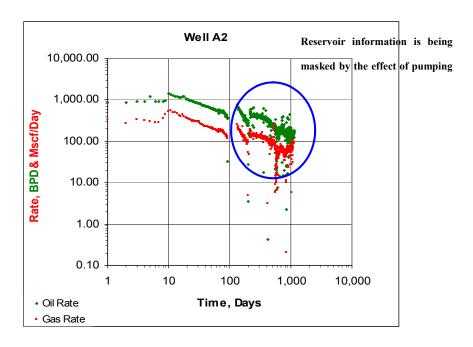


Figure 5.4 Example of Scattering Data Well Due to Field Operation.

The well example above is having 1000 days of production data available. It is almost 3 years production data. This well shows high rates of scattering or fluctuating production data at the end because of pumping unit. It is hard to analyze the well like this because the reservoir information cannot be recognized or identified.

### **5.2.2** Analysis with Superposition Time Functions

Field data are not always as perfect as synthetic data, and sometimes they are difficult to identify flow regimes in the log-log plot. Superposition time has been proposed to deal with high rates of scattering or fluctuating production data. The original generalization for superposition time was from Coat (Coats et al 1964). In his paper influence function F(t) for constant production rate was given as Eq.1 below

$$\Delta p(t) = q F(t) \qquad (1)$$

For production rate changing with time F(t) was given as Eq. 2 below

$$\Delta p_n = \sum_{i=1}^n (q_i - q_{i-1}) F(t_n - t_{i-1})$$
 (2)

The function of F(t) can be given in different formats depend on the Type of reservoir:

- For PSS F(t) function is : a + b\*t
- For infinite acting radial F(t) function is : a + b\*log(t)
- For linear flow reservoir F(t) function is:  $a + b*\sqrt{t}$
- For bilinear flow reservoir F(t) function is:  $a + b* \sqrt[4]{t}$

Superposition time equations are also depending on the Type of the interesting in reservoir Type or F(t):

• PSS the superposition time is given as

$$t_{-}\sup = \sum_{i=1}^{n} \frac{(q_{i} - q_{i-1})(t_{n} - t_{i-1})}{q_{n}}.$$
(3)

• Infinite acting radial case the superposition time is given as

$$t_{-}\sup = a + b\sum_{i=1}^{n} \frac{(q_{i} - q_{i-1})\log(t_{n} - t_{i-1})}{q_{n}}.$$
 (4)

• Linear flow reservoir the superposition time is given as

$$t_{-}\sup = a + b\sum_{i=1}^{n} \frac{(q_{i} - q_{i-1})\sqrt{(t_{n} - t_{i-1})}}{q_{n}}$$
 (5)

When the production rate is affected by field operation such as multiple shut in or pumping unit time periods, superposition time should be used to improve the analyzing. Figure 5.5 below is an example of a well with multiple rates changing periods because of pumping unit. Figure 5.6 is the log-log plot of rate vs. normal producing time. Figure 5.7 is the specialized plot of (pi-pwf)/q vs.  $\sqrt{t}$  notice that this is the square root of normal production time.

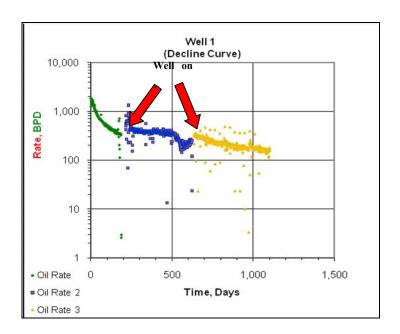


Figure 5.5 Semi Log Plot of Rate vs. Normal Time.

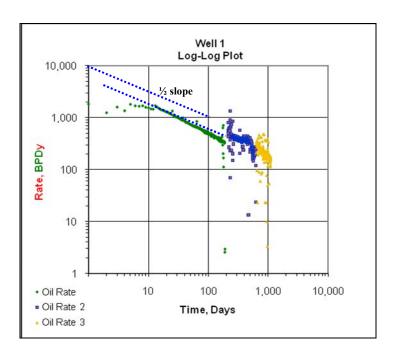


Figure 5.6 Log-Log Plot of Rate vs. Normal Time.

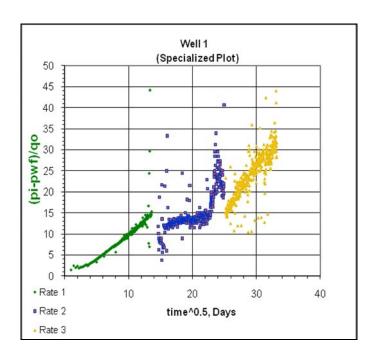


Figure 5.7 Specialized Plot of (pi-pwf)/qo vs. sqrt (t).

It is hard to identify the linear flow regime for this well on the log-log plot and specialized plot because of multiple rate changing periods. Figure 5.8 below shows the specialized plot of  $(pi-p_{wf})/qo$  vs. the superposition time with respect to square root of t is used. The reservoir is still in the transient linear flow and has not reached the boundary dominate flow yet, as shown in Figure 5.8. This section will not try to analyze the flow regime for this particular well but just give a general idea of using superposition time. The specific flow regime analyzing on this well will be given again on the field case examples section.

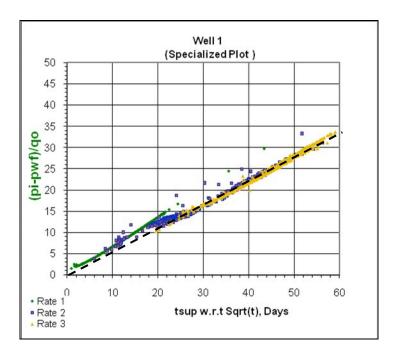


Figure 5.8 Specialized Plot of tsup with Respect to sqrt (t).

# **5.2.3** Analysis with Derivative Functions

Similar to well test analysis, derivative functions can help to identify the flow regime of the reservoir. Table 5.1 below is the summary of derivative functions and their application.

**Table 5.1 Summary of Derivative Functions.** 

Flow Regimes	Derivative Functions	Slope Observed	Observation on Log-Log Plot	
Bilinear	$\frac{d(p_i - p_{wf})/q}{d\sqrt[4]{t}} \text{ vs. } \sqrt[4]{t}$	0 slope	½ slope	
Linear	$\frac{d(p_i - p_{wf})/q}{d\sqrt{t}} \text{ vs. } \sqrt{t}$	0 slope	½ slope	
BDF	$\frac{d(p_i - p_{wf})/q}{dt} \text{ vs. t}$	0 slope	Exponential Decline	

It is better to combine the use of superposition time with the derivative function to make the interpretation more effectively. Instead of taking derivative with respect to  $\sqrt[4]{t}$ ,  $\sqrt{t}$  or t, the superposition time with respect to  $\sqrt[4]{t}$ ,  $\sqrt{t}$  or t should be used to make the derivative functions. Table 5.2 is the summary of derivative functions taking with superposition time functions.

Table 5.2 Summary of Derivative Functions Using with Superposition Time.

Flow Regimes	Superposition t w.r.t F(t)	Derivative Functions	Slope Observed	Observation on  Log-Log Plot
Bilinear	$\sqrt[4]{t}$	$\frac{d(p_i - p_{wf})/q}{d_t \sup}$ vs. Time	0 slope	1/4 slope
Linear	$\sqrt{t}$	$\frac{d(p_i - p_{wf})/q}{d\_t \sup} \text{ vs. Time}$	0 slope	½ slope
BDF	t	$\frac{d(p_i - p_{wf})/q}{d_t \sup} \text{ vs. Time}$	0 slope	Exponential Decline

# 5.2.4 Appling Smoothing Method to Identify Flow Regimes

The disadvantage of derivative functions is that they are leaving a lot of noised data on the plot. Figure 5.9 below is an example to show how noisy the derivative is.

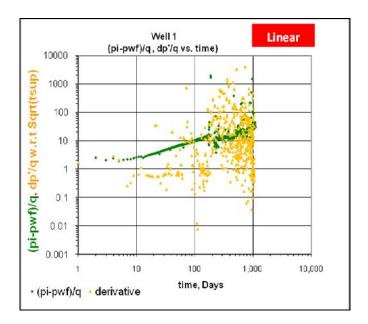


Figure 5.9 Derivative Plot Shows Noised Data on the Plot.

Figure 5.9 is the log-log plot of (pi-pwf)/qo and its derivative with respect to superposition time of square root. It is supposed to see a zero slope from the early time until 15 days because a linear flow period is identified on the log-log plot as shown in Figure 5.6. Since the derivative shows very noisy, so it is hard to recognize the flow regimes from the derivative plot without applying some smoothing technique.

Bourdet (Bourdet et al 1984) applied the smoothing technique in their well test analysis. They gave the formula for the smoothing technique which is shown as Eq. 5 below:

$$(dp/dX)_{i} = \frac{[(\Delta p_{1}/\Delta X_{1})\Delta X_{2} + (\Delta p_{2}/\Delta X_{2})\Delta X_{1}]}{(\Delta X_{1} + \Delta X_{2})}.$$
(5)

They also introduced the smoothing factor L such as the minimum distant between the abscissa of the points and the point of interested point i. Noised data can be

efficiently removed when L is choosing carefully. It is difficult to choose the right value for L because if L is too distant away from i the shape of the original curve will be distorted. Figure 5.10 below is an example of the derivative function plot, which is applied Bourdet smoothing. It shows the zero slope at the early time until 15 days indicating linear flow period as shown in the small circle in Figure 5.10 below

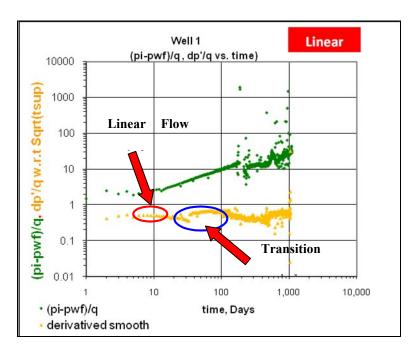


Figure 5.10 Derivative with Bourdet Smoothing.

The smoothing factor applied for the Figure. 5.10 is L = 6.5. It is the minimum distant between abscissa of the points and the point of interested for superposition time. Figure 5.11 below is using L = 9.5 and it also shows zero slope at early time, but the transition period, between the linear flow to the another period, is distorted. Figure 5.12 shows the original curve is distorted because of using over smooth value of L = 12.

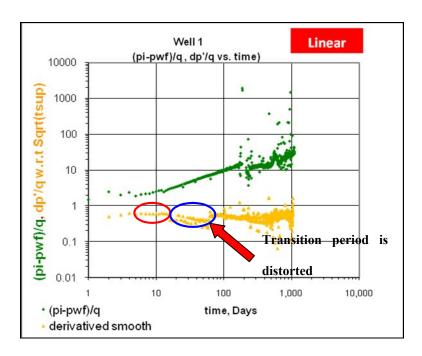


Figure 5.11 Smoothed Derivative with L = 9.5.

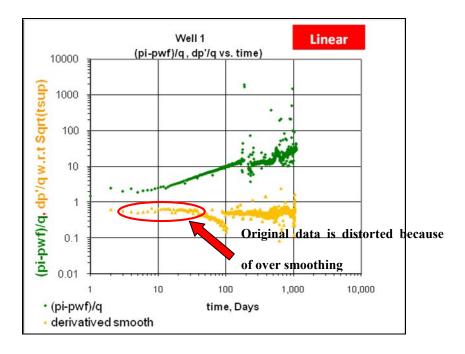


Figure 5.12 Over Smoothed Derivative L= 12.

Below are the summary of the procedures for analyzing field data with combining superposition time and derivative functions including derivative smoothing method:

- Stepwise Analysis Procedure for Using Superposition Time Combine with Derivative Functions:
  - 1. Calculate superposition time with respect to t,  $\sqrt{t}$ ,  $\sqrt[4]{t}$ , etc depend on the interested flow regimes.
  - Sort the superposition time. It is better to sort it before using it to make derivative to reduce the noises.
  - Take derivative with respect to superposition time of the interested flow regime.
  - 4. Apply smoothing method to smooth the derivative.
  - 5. Plot the derivative functions with the normal time.

### **5.3 More Field Case Examples**

Previous sections are showing the procedures in analysis field production data.

This section is showing more field data example including all the steps which described in previous sections.

## 5.3.1 Well DEBRA RAUCH 1-1 H

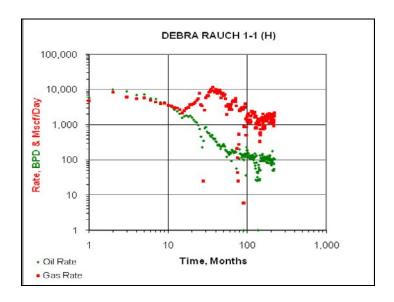


Figure 5.13 Example Field Case DEBRA RAUCH 1-1 H.

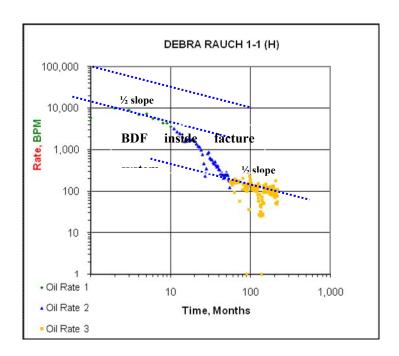


Figure 5.14 Log-Log Plot of Oil Rate vs. Producing Time.

As Figure 5.14 shows two different linear flow periods on the plot. There is one period of pressure drop reaches the end of fracture network in between the two linear curves. It is considered as the BDF of fracture system. To make sure there are linear flows in this well, a specialized plot of (pi-pwf)/qo is plotted with square root of producing time. Figure 5.15 below shows the specialized plot of this well.

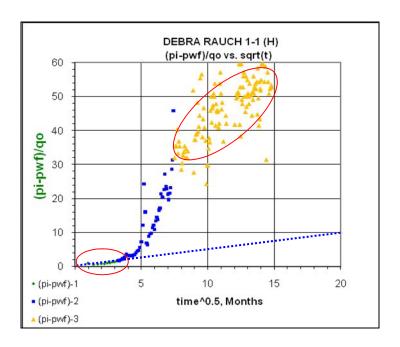


Figure 5.15 Specialized Plot of (pi-pwf) vs. Normal Time.

As shown in Figure 5.15 it is hard to identify the second linear flow period on the specialized plot of (pi-pwf) vs. normal producing time because of the high rate of scattering of the data during this period. The first linear period is obviously seen on the plot as the straight line indicating linear flow.

The specialized plot of (pi-pwf) vs. superposition time of the square root of t is another way to analyze the flow regime. Figure 5.16 below shows the specialized plot of (pi-pwf) vs. superposition time of the square root of t.

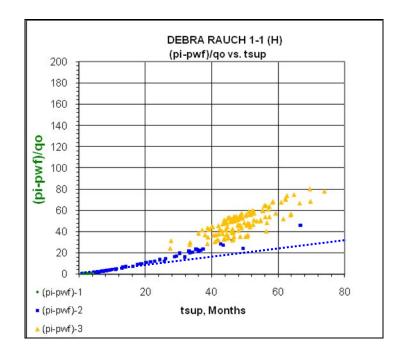


Figure 5.16 Specialized Plot of (pi-pwf) vs. tsup.

As shown in Figure 5.16, even though using the superposition time the second linear flow still cannot be identify. To better analyze the second flow regime now, derivative function and smoothing method need to be used. Figure 5.17 is the plot of derivative with smoothing method L=12.

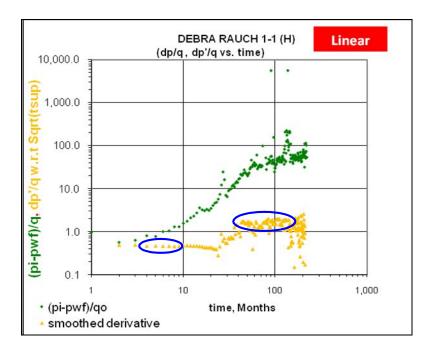


Figure 5.17 Derivative with Smoothing Method for Linear Flow with L = 12.

As shown in Figure 5.17, first linear flow period is clearly identified followed by transition period. The second linear flow period is reasonable identified. Figure 5.18 shows the derivative smoothing with L=18, and it is easy to see that a over smoothed value because the curve after the early period is distorted.

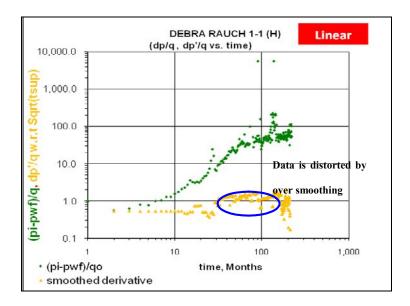


Figure 5.18 L= 18 is over Smoothed Value.

To identify the BDF, the derivative function taking superposition with respect to t is used and plotting with (pi-pwf)/qo as shown in Figure 5.19 below.

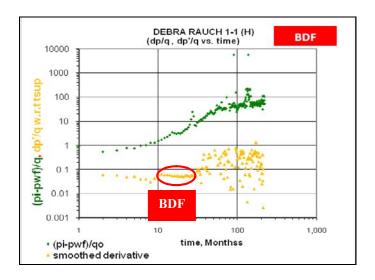


Figure 5.19 Plot with Derivative Smoothing to Identify BDF L =12.5.

# 5.3.2 Well BUCKHORN FEDERAL A 2

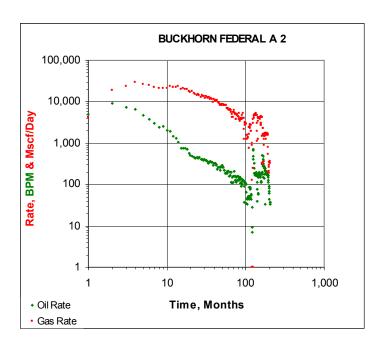


Figure 5.20 Example Field Case Well BUCKHORN FEDERAL A 2.

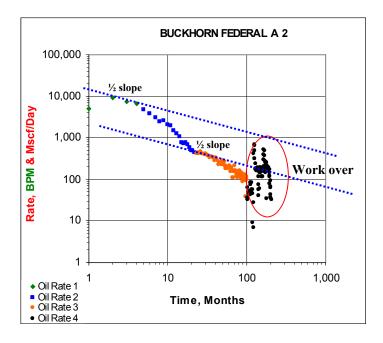


Figure 5.21 Log-Log Plot of Rate vs. Normal Producing Time.

Figure 5.21 shows two different linear flow periods on the plot. There is one period of BDF, when the pressure drop reaches the end of fracture inside the fracture network, in between the two linear curves. It is considered as the BDF of fracture system. To make sure there are linear flows in this well, a specialized plot of (pi-pwf)/qo is plotted with square root of producing time. Notice that the second linear flow period is happened quickly less than a month. This make the second linear flow period may be harder to identify on the smoothed derivative.

Figure 5.22 below shows the specialized plot of this well using normal producing time. When the straight line is identified on the specialized plot, it is indicating linear flow. Notice on the log-log plot of Figure 5.21 above, it shows two ½ slope lines indicating two linear flow periods. The first linear flow is the flow from fracture network

to well, and it is last for 3 months. The second linear flow is the flow from matrix to fracture network, and it is last for less than 1 month. We will expect two straight lines on the specialized plot.

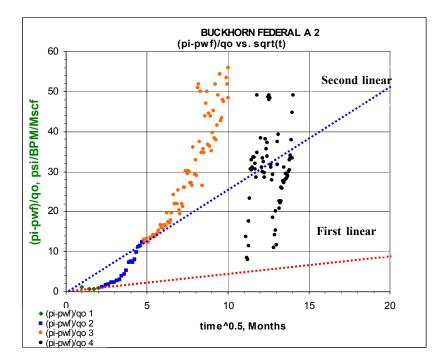


Figure 5.22 Specialized Plot of (pi-pwf) vs. Normal Time.

This well is obviously seen two periods of linear flow. One from fracture to the well and the second linear flow is from matrix to the fracture network.

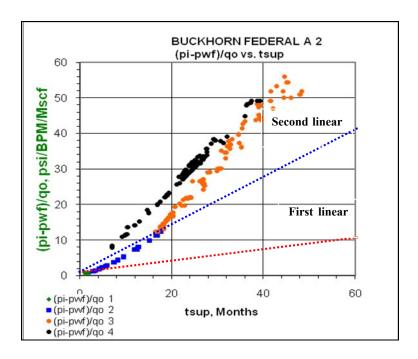


Figure 5.23 Specialized Plot of (pi-pwf) vs. Superposition Time of sqrt (t).

Two straight lines are indicating two linear flow periods as seen on Figure 5.22 and Figure 5.23.

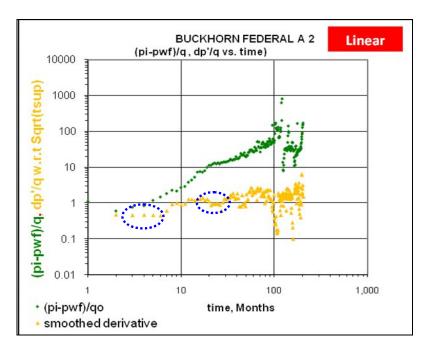


Figure 5.24 Derivative with Smoothing Method for Linear Flow with L = 3.2.

As seen on Figure 5.24 the first and second period linear flow can be identified on the smoothed derivative plot, but second period of linear flow duration is really short. Figure 5.25 shows how the data curve is distorted when using over smooth L=5 value

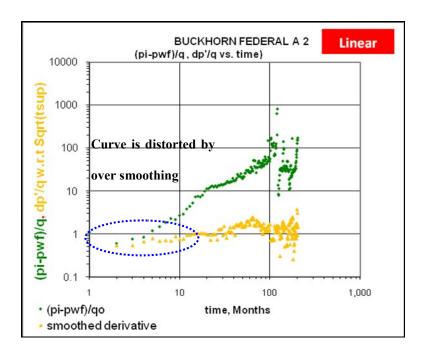


Figure 5.25 Over Smoothing with L = 5.

The BDF are also identified on the log-log plot of Figure 5.21 with early BDF periods.

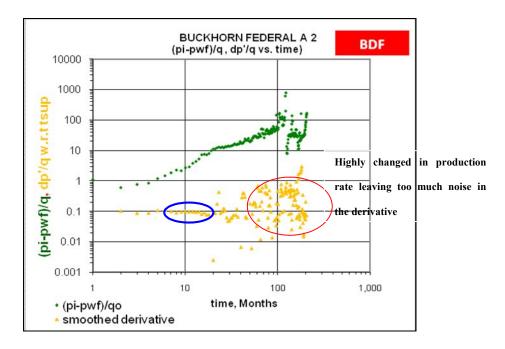


Figure 5.26 Derivative with Smoothing Method for BDF with L = 5.

As seen on the Figure 5.26, the first BDF, inside the fracture system, is identified but the second BDF period, inside the matrix, is not able to identify. This is because the second BDF period has high rate of scattering or significant fluctuating in flow rate and it make superposition time hard to be used in the interpretation. These issues of superposition time are giving in the tables below. When the rate is constant, the superposition time is the same as the normal producing time Table 5.3. When the rate is slightly change or low rate of fluctuating, superposition time is fine to use and it will do a good job in interpretation as show in Table 5.4. It is also shown in Table 5.5 the issues of superposition time. When the rate is highly changed, superposition time is also changed significantly and this may bring more noise to the derivative functions.

Applying smoothing method to this highly noised data will give some misleading in interpretation.

Table 5.3 Superposition Time is Same as Normal Time for Constant rate.

n	time	rate	Tsup
1	0	500	0
2	5	500	5
3	10	500	10
4	15	500	15
5	20	500	20
6	25	500	25
7	30	500	30
8	35	500	35
9	40	500	40
10	45	500	45

Table 5.4 Superposition Time is Work Fine for Low Change of Production Rate.

n	time	rate	Tsup
1	0	500	0
2	5	502	5
3	10	510	9.921569
4	15	511	14.90215
5	20	512	19.87305
6	25	459	27.16776
7	30	508	29.54724
8	35	519	33.921
9	40	530	38.21698
10	45	545	42.16514

Table 5.5 Superposition Time is Significantly Changed when the Rate has been Highly Changed.

n	time	rate	Tsup
1	0	410	0
2	5	663	5
3	10	1500	7.21
4	15	492	26.98171
5	20	2000	11.6375
6	25	241	101.5768
7	30	5	4901
8	35	10	2455.5
9	40	68	366.1029
10	45	62	406.5323
11	50	44	577.8409
12	55	1	25430

## **5.4 Chapter Summary**

• It is better to use multiple diagnostic plots to perform the flow regime analysis.

One diagnostic plot may not contain all the reservoir information which engineers are looking for. For example, linear flow may not be seen clearly on specialized plot but it may show clearly with the smoothing derivative plot.

- Superposition time is worked fine for the production rate, which does not have significantly change in the production rate, in another work it is required a good production data before applying the superposition time.
- Smoothing factor L must be chosen carefully in order to avoid over smoothing.

## **CHAPTER VI**

## **OIL IN PLACE ESTIMATION**

#### **6.1 Introduction**

This chapter will perform the oil in place estimation base on transient dual porosity model. Two wells will be chosen to perform the calculations. Candidate wells are from the 95 wells provided by the sponsor companies which have complete PVT, pressure data. The reason why 146 wells which have 20 years of production data are not chosen is because they do not have PVT or pressure data in order to perform the calculation.

# **6.2 Transient Dual Porosity Slab Model for Linear Reservoir-** (Bello et al, 2008).

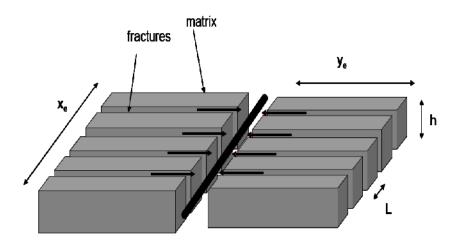


Figure 6.1 Slab Matrix Model for Hydraulic Fracture Well (Bello et al, 2008).

They used this model for hydraulic fracture gas well. This section will use this model for hydraulic oil well, and applying oil equation which presented on El-Banbi dissertation. (El-Banbi 1998)

The equation for estimation OOIP was given as below:

$$OOIP = \frac{19.91\sqrt{t_{ehs}}(1 - S_{w})}{c_{m_{A}}}.$$
(6.1)

For calculation  $A_{cm}$  which describe as total fracture/matrix surface are which drain into the fracture system the equation is given as below:

$$\sqrt{k_m} A_{cm} = \frac{125.1B\mu}{\sqrt{(\phi\mu c_t)}} \frac{1}{m_4}$$
 (6.2)

## **6.3 Field Case Application**

#### 6.3.1 WELL-5

 Identify flow regimes: Before applying calculation flow regimes analysis need to be performed. Figure. 6.2 below is the log-log plot of rate vs. normal producing time.

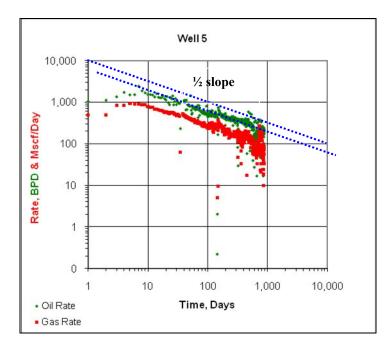


Figure 6.2 Log-Log Plot of Rate vs. Producing Time.

As seen on Figure 6.2 above, the well produced for almost 3 years. Linear flow is the dominated flow for the entire period of production. To make sure the linear flow is the dominated flow, specialized plot of (pi-pwf) vs. Sqrt (t) is plotted as Figure 6.3 below, note that t is the normal producing time.

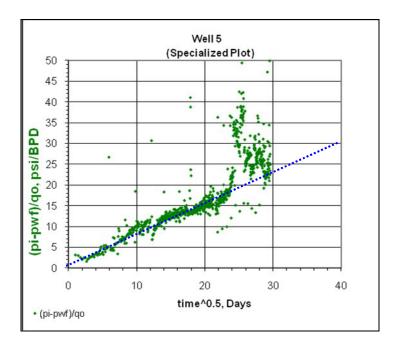


Figure 6.3 Specialized Plot of (pi-pwf) vs. sqrt (t).

It is hard to identify the straight line for linear flow in this Figure 6.3 because the production rate is scattering and fluctuating. To make sure the flow regime is linear flow, the specialized plot of (pi-pwf)/qo vs. superposition time of Sqrt (t) is plotted as Figure. 6.4 below.

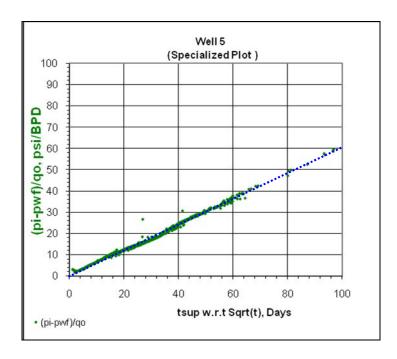


Figure 6.4 Specialized Plot of (pi-pwf)/qo vs. Superposition Time of sqrt (t).

It is obviously seen that the well is still in transient flow period with linear flow is dominated. The m<sub>4</sub> slope of Figure 6.3 is used to calculate the OOIP using Eq. 6.1.

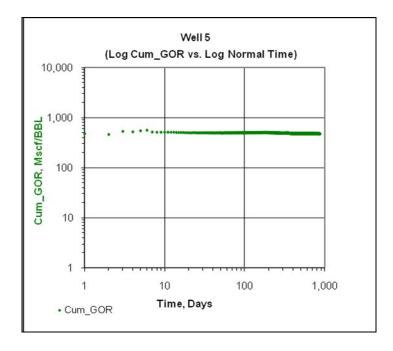


Figure 6.5 Shows Cum GOR is Constant.

#### • *OOIP* calculation:

As shown in Figure 6.5 Cum\_GOR is constant so it is confirmed that gas did not release out of solution. Oil compressibility is calculated as Eq.6.3 below:

$$C_o = -\frac{1}{B_o} \frac{\Delta B_o}{\Delta p} \tag{6.3}$$

Calculated  $C_o$  using Eq 6.3 above is 10.7E-6 and assuming water compressibility is 3E-6.

$$C_t = C_o S_o + C_w S_w + C f = 10.7 \text{E} - 6*0.77 + 3* \text{E} - 6*0.23 + 3 \text{E} - 6 = 11.875 \text{E} - 6$$

The total compressibility is equal to 11.875E-6 with 77% oil saturation. The slope of  $m_4$  is 0.75 and  $\sqrt{t_{esh}}$  is 24 with that the *OOIP* is calculated as

$$OOIP = \frac{19.91\sqrt{t_{ehs}}(1 - S_w)}{c_t m_4} = \frac{19.91*24*0.77}{16.7*10^{-6}*0.75} = 41.311.MMBBL$$

## 6.3.2 WELL-6

Identify flow regimes: Figure. 6.6 below is the log-log plot of rate vs.
normal producing time. The well produces 1000 days and reaches the
BDF. Figure 6.7 is the specialized plot of (pi-pwf)/qo vs. square root
of normal producing time.

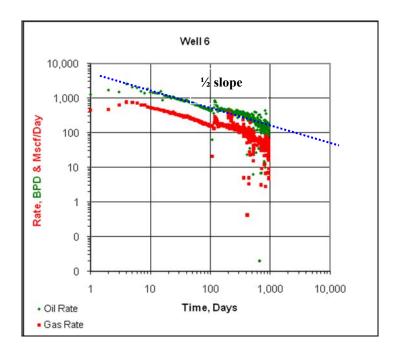


Figure 6.6 Log-Log Plot of Rate vs. Normal Time.

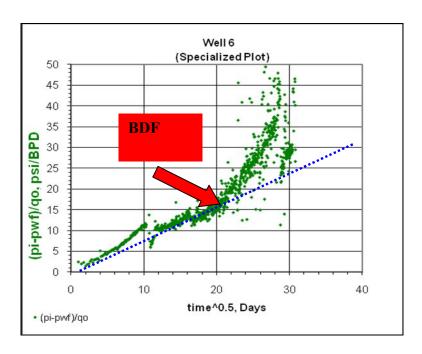


Figure 6.7 Specialized Plot of (pi-pwf)/qo vs. sqrt (t).

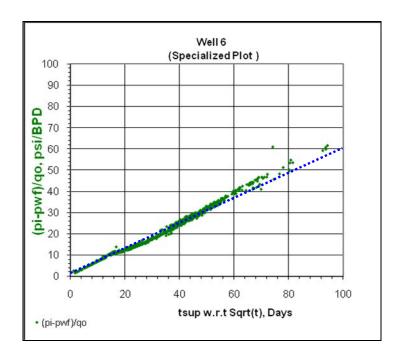


Figure 6.8 Specialized Plot of (pi-pwf)/qo vs. Superposition Time w.r.t sqrt (t).

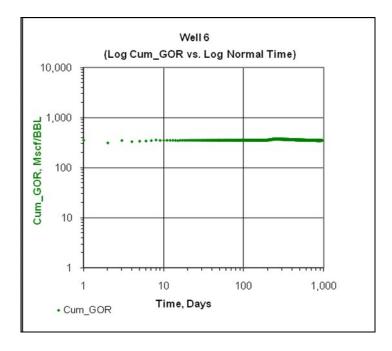


Figure 6.9 Shows the GOR is Constant.

#### • *OOIP* calculation:

As shown in Figure 6.7 Cum\_GOR is constant so it is confirmed that gas did not release out of solution. Calculated  $C_o$  using Eq 6.3 above is 10.63E-6 and assuming water compressibility is 3E-6

$$C_t = C_o S_o + C_w S_w + C_f = 10.63 \text{E} - 6*0.77 + 3* \text{E} - 6*0.23 + 3 \text{E} - 6 = 11.875 \text{E} - 6$$

The total compressibility is equal to 11.875E-6 with 77% oil saturation. The slope of  $m_4$  is 0.775 and  $\sqrt{t_{esh}}$  is 22 with that the *OOIP* is calculated as

$$OOIP = \frac{19.91\sqrt{t_{ehs}}(1 - S_w)}{c_t m_4} = \frac{19.91 * 22 * 0.77}{11.875 * 10^{-6} * 0.775} = 33.008.MMBBL$$

## **CHAPTER VII**

#### CONCLUSIONS AND RECOMMENDATIONS

#### 7.1 Conclusions

The major conclusions of this work can be summarized as follows:

- The oil production in the Bakken formation is affected by several factors including drilling technologies, completion technologies, and hydraulic fracture technologies, as well as pipeline capacity and crude oil transportation issues in the area.
- In the Bakken Shale, Type I is production trend associated with the reservoir pressure drops below bubble.
- In the Bakken Shale, Type II production does not have fracture dominated flow only matrix flow resulting in lower oil recovery than Type I production.
- Type I category A: the flow in this category has fracture dominated flow with a weak to mediated matrix supporting.
- Type I category B: the flow in this category has strong matrix supporting resulting in gas is producing with it associated oil.
- Type I category C: This is the fracture dominated flow only without matrix supporting.
- Production in the Bakken Shale is better where the location have extensive natural fractures systems and supporting by matrix porosity, the well production is more economically attractive.

- It is better to use multiple diagnostic plots to perform the flow regime analysis.
- Superposition time is worked fine for the production rate, which does
  not have significantly change in the production rate, in another work
  it is required a good production data before applying the superposition
  time.
- Smoothing factor L must be chosen carefully in order to avoid over smoothing.

#### 7.2 Recommendations for Future Works

The following recommendations are listed:

- Apply the triple porosity concept to explain for the reservoir mechanism under Type I and Type II production trends.
- Run more simulation models to match the behavior of Type I category B, and C.

## **NOMENCLATURE**

 $A_{cm}$  = total matrix surface area draining into fracture system, ft<sup>2</sup>

B = liquid formation volume factor, rB/STB

 $c_t$  = liquid total compressibility, psi<sup>-1</sup>

 $k_m$  = matrix permeability, md

 $p_i$  = initial reservoir pressure, psi

 $p_{wf}$  = wellbore flowing pressure, psi

t = time, days

# **Greek symbols**

 $\mu$  = viscosity, cp

 $\phi$  = porosity

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#### **APPENDIX A**

#### DERIVATION SUPERPOSITION TIME FUNCTION WITH DIFFERENT F(t)

From Coats (Coats et al 1964) for constant q the pressure change at inner boundary at time t is:

$$\Delta p(t) = q F(t)$$
 (A-1)

Suppose the rate is not constant and changes with time for  $t_1$ ,  $t_2$ ,  $t_3$ :

$$\Delta p(t) = q_1 F(t_3) + (q_2 - q_1) F(t_3 - t_1) + (q_3 - q_2) F(t_3 - t_2) - \dots$$
 (A-2)

So,

$$\Delta p_3 = \sum_{i=1}^3 (q_i - q_{i-1}) F(t_3 - t_{i-1}). \tag{A-3}$$

In general with rate changing n time:

$$\Delta p_n = \sum_{i=1}^n (q_i - q_{i-1}) F(t_n - t_{i-1}) \qquad (A-4)$$

Let F(t):  $a + b\sqrt{t}$  so A-4 is equal to:

$$\Delta p_n = \sum_{i=1}^n (q_i - q_{i-1})(a + b\sqrt{(t_n - t_{i-1})}....(A-5)$$

A-5 will become as below:

$$\Delta p_n = \sum_{i=1}^n (q_i - q_{i-1})a + \sum_{i=1}^n (q_i - q_{i-1})b\sqrt{(t_n - t_{i-1})}$$
 (A-6)

After summation of all the rate change result in  $q_n$ , then A-6 is equal to:

$$\Delta p_n = q_n a + b \sum_{i=1}^{n} (q_i - q_{i-1}) \sqrt{(t_n - t_{i-1})}$$

Divided both side for qn, then A-6 is equal to:

$$\frac{\Delta p_n}{q_n} = a + b \sum_{i=1}^n \frac{(q_i - q_{i-1})\sqrt{(t_n - t_{i-1})}}{q_n} \dots (A-7)$$

Superposition Time with respect to Sqrt (t) is:

$$t \sup er = \sum_{i=1}^{n} \frac{(q_i - q_{i-1})\sqrt{t_n - t_{i-1}}}{q_n}$$
 (A-8)

The derivation of superposition time w.r.t log (t) and t is similar as above.

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