THE EFFECT OF WELL TRAJECTORY ON PRODUCTION PERFORMANCE OF TIGHT GAS WELLS

A Thesis

by

MOHAMMAD F KH O KH ALDOUSARI

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

December 2011

Major Subject: Petroleum Engineering

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Approved by:

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ABSTRACT

The Effect of Well Trajectory on Production Performance of Tight Gas Wells.

(December 2011)

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Chair of Advisory Committee: Dr. Ding Zhu

Horizontal wells are a very important element in the oil and gas industries due to their distinguished advantages. Horizontal wells are not technically horizontal because of the structural nature of reservoir formations and drilling procedures. In response to the reservoir rock's strength, the horizontal well deviates upward and downward while being drilled forming an undulating path instead of a horizontal. In this study, horizontal wells with an undulating trajectory within a gas reservoir were studied. The aim of this research is to investigate the effect of the trajectory angle on pressure drop in horizontal wells. In addition, the contribution of water flow to pressure drop is a part of this research. Generally, water comes from different sources like an aquifer or a water flood job. In low permeability horizontal wells, hydraulic fracturing introduces water to gas wells. Water distribution is an important issue in gas wells production. In order to achieve the goal of this study, a model has been developed to simulate different situations for a horizontal well with an undulating trajectory in gas reservoirs. This study results that a symmetric trajectory has a minimum effect on pressure drop distribution. In addition, a small increment in water flow rate could lead to killing the well.

DEDICATION

This research is dedicated to my inspiration, Dr. Eissa M. Al-Safran, and all the faculty members in petroleum engineering department at Kuwait University. Without you all, none of this could happen. Thank you.

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Praise and gratitude to Allah, the Almighty, for the abundant mercies and blessings, and to his Prophet Mohammed, peace be upon him.

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CHAPTER I

INTRODUCTION

1.1 Background

In oil and gas production, inflow and outflow are an essential aspect of the process. In order to develop outflow and inflow analysis, pressure drop calculation in a well system is essential. In the oil and gas industry, water is considered enemy number one due to several implications caused by water production. In this study, water production and its effect in a horizontal well in a gas reservoir has been analyzed. The effect of water flow on pressure drop calculation has been considered. Water is a serious issue that can easily lead to reducing gas production rate or even killing the well if not studied carefully and handled properly.

Water has many sources in oil and gas reservoirs. The most common source is a reservoir aquifer. Aquifers support reservoir pressure in case of depletion by sweeping the hydrocarbon from reservoir rock pores. Since water is the heaviest fluid in reservoir fluids, it increases fluid mixture density. Density is the main function of gravitational pressure drop leading to a massive pressure drop.

Another source of water is water flooding operations. The amount of water being injected eventually will be produced leading to all previously mentioned problems. Lastly, fracturing a tight reservoir might facilitate water path to production.

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

In this study, the light is shed on horizontal well trajectory. Because of the nature of reservoir formation and the different kind of stresses inside the reservoir, horizontal wells cannot be drilled with zero angle. In other words, it has a zigzag shape which results in an undulating trajectory. The effect of undulating is also a part of the research.

1.2 Literature Review

There are two main components in this study: reservoir performance and wellbore pressure drop. Many models have been published to evaluate the well performance in horizontal wells. These models are classified based on the flow condition as either steady-state or pseudo-steady-state. Joshi (1988) presented a model for steadystate flow condition assuming an elliptical drainage area. He handled the three-dimensional flow problem by separating the horizontal flow into x-y plane and y-z plane and treating them separately. Butler (1994) and Furui (2003) presented steady-state models for box-shaped reservoirs. Their models yield very similar results, although they are derived by different approaches. Butler's model was based on the image well superposition technique, whereas Furui's model was based on the finite element simulation results. On the other hand, Babu and Odeh (1989) presented a pseudo-steady-state model that is widely used for horizontal well productivity. The model assumes a box-shaped reservoir and a well parallel to the x-direction. All the above models are for incompressible or slightly compressible single-phase liquid; however, they can be extended to other fluid types.

Beggs-Brill correlation is one of the most commonly used models to calculate pressure drop in horizontal pipe. It was developed from experimental data obtained in a small scale test facility (1in diameter pipe with air and water). The correlation was developed from 584 measured tests for all inclination angles. Even though it was originally developed for horizontal well with zero angle, at a later stage a correction parameter was introduced to account for different inclination angles. Fluid flow pattern is determined first, and then based on flow pattern, pressure drop due to friction, gravitation, and acceleration is calculated (Beggs and Brill, 1973).

Xiao model is a comprehensive mechanistic model developed for gas-liquid two phase flow in horizontal and near horizontal pipelines. It has been evaluated against a data bank that includes field data, and laboratory data published in literature (Xiao, Shoham, and Brill 1990).

The ranges of contribution of elevation, friction, and acceleration in the total pressure drop in the well can be from Table 1, where the contributions are listed as percent of total pressure drop in the tubing for both oil and gas wells (Beggs, 2003).

Table 1 Percent of total pressure drop due to elevation, friction, and acceleration

Component	Oil Wells	Gas Wells
Hydrostatic	70-90%	20-50%
Frictional	10-30%	30-70%
Acceleration	0-10%	0-10%

The numbers given in the table are, of course, only approximations, since some oil wells produce at high gas/liquid ratios (GLRs) and some gas wells produce considerable amounts of liquid condensate or water which may lead to change of the percentage. Table 1 gives an idea that in general, for oil wells, hydrostatic pressure drop dominates the flow; but for gas wells, frictional pressure can be more significant than hydrostatic. In any case, the acceleration term is small, and it is usually neglected in pressure drop calculations.

1.3 Objectives

The objective of this study is to investigate the effect of well trajectory and other parameters on well performance of gas wells. To achieve this objective, a model is needed first. This model has been built on the Beggs and Brill correlation (1973) and the Babu and Odeh (1989) inflow equation with other fluid properties correlations, which will be discussed later in methodology.

The inflow model calculates gas and water flow rates in the well and then the pipe flow model calculates the pressure drop along the horizontal well (assuming that toe pressure is known). As a result, the model will produce $P_{wf}(x)$ vs $q(x)$.

Taking advantage of the fast computational power, GWR (Gas Water Ratio) is changed while holding everything else constant to illustrate the effect of the water production on pressure drop calculation. Using deferent values for GWR will give us an idea about when the water is going to be detrimental to production. This can be used as a monitoring tool to insure water flow rates stay below a certain value by reducing the water flowing into the well either by cementing the water zone perforation or other operations to minimize water production. Basically, this will be given as liquid flow rate vs pressure drop.

In addition to the issues mentioned before, the trajectory angle should be controlled in well design. Different trajectory angles have different pressure drops associated with it. Based on the results of this study, recommended well trajectory design can be obtained.

CHAPTER II

METHODOLOGY DEVELOPMENT

2.1 Introduction

In this chapter, the methodology used to create horizontal well pressure distribution is discussed. The methodology consists of two main components; the inflow model and the wellbore model. The flow from reservoir to the horizontal well is calculated by the inflow model. In this part of the model, Babu and Odeh (1989) pseudosteady state inflow equation is used. This equation gives the gas flow rate. A GWR (Gas Water Ratio) is used to calculate water flow rate. Dividing gas flow rate by GWR will give us water flow rate. The second part of the model is the pressure drop calculation inside the wellbore. Beggs and Brill (1973) correlation and other correlations are used for pressure drop based on gas and water properties.

The objective of this study is to investigate the effect of well trajectory and water production on gas well performance. A physical model of undulating wellbore used in this study is shown in Figure 1.

2.2 Reservoir Inflow

The inflow rate of a horizontal well is calculated by an analytical model developed by Babou and Odeh. The inflow model is derived on a system shown in Figure1.

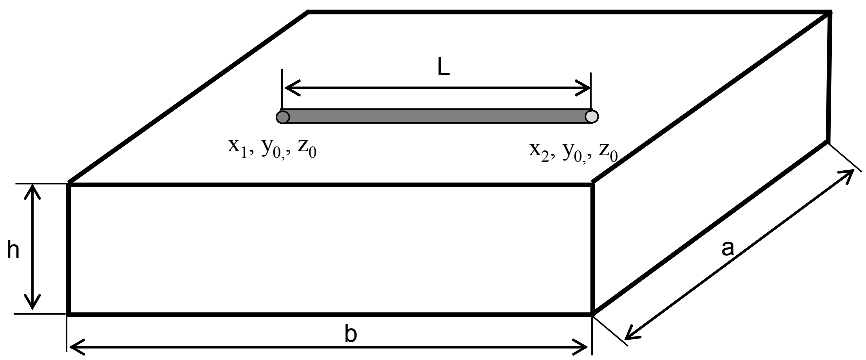

Figure 1 Schematic of Babu and Odeh's model (Hill et al. 2008).

The detailed discussion of this model has been illustrated before (Babou and Odeh, 1989) For a system shown in Figure 2, we need to divide the wellbore into smaller segments in order to consider the effect of wellbore trajectory and the wellbore pressure drop on flow rate. This will be discussed in later chapters. The reservoir inflow equation to a well system is given by (Babou and Odeh, 1989) Equation 2.1.

$$q_{g3} = \frac{L(k_v k_h)^{0.5}(\overline{p}^2 - p_3^{\ 2})}{1424 z\mu_g T[\ln \frac{A^{0.5}}{r_w} + \ln C_H - 0.75 + S]} \tag{2.1}$$

L: Length of segment, ft

k_v: Vertical permeability, md

k_h: Horizontal permeability, md

$\overline{p}$: Average reservoir pressure, Psia

p_A: Pressure at point A, Psia

z: Reservoir gas compressibility factor

μ_g: Reservoir gas viscosity, cp

T: Reservoir temperature, R

A: Reservoir area, A=ah, ft^2

a: Reservoir width, ft

h: Reservoir thickness, ft

rw: Horizontal wellbore, ft

$\ln C_H$: Shape factor

S: Skin factor

q_{gA}: Gas flow rate into the segment of horizontal well, Mscf/d

Conventionally, for a two-phase flow model problem, Vogal's Correlation is used to calculate liquid phase rate, then gas flow rate is estimated by using GOR (gas oil ratio). For the problem studied, since gas flow is the dominated fluid, we use Babu and Odeh equation to calculate gas flow rate. Babu and Odeh derived simplified equation to calculate the shape factor, lnC_H,:

$$\ln C_H = 6.28\frac{a}{h}\sqrt{\frac{k_z}{k_y}}\left[\frac{1}{3} - \frac{y_0}{a} + \left(\frac{y_0}{a}\right)^2\right] - \ln\left(\sin\frac{\pi z_0}{h}\right) - 0.5\ln\left[\left(\frac{a}{h}\right)\sqrt{\frac{k_z}{k_y}}\right] - 1.088 \tag{2.2}$$

Equation (2.1) gives how much gas flows into the segment of a horizontal well. In this study everything in equation (2.1) is constant except p_A because the study is to compare the flow rate for the same reservoir under pseudosteady state conditions, reservoir average pressure is hold constant in a defined period, and only declines at constant rate. p_A is an input to carry on the calculation. The Equation2.3 is used to calculate water flow rate. Oil or gas condensate is treated as a part of the liquid phase with water.

$$q_{w3} = \frac{q_{g3}}{GWR} \tag{2.3}$$

q_w: Water flow rate, STB/d

GWR: Gas water ratio, Mscf/ STB

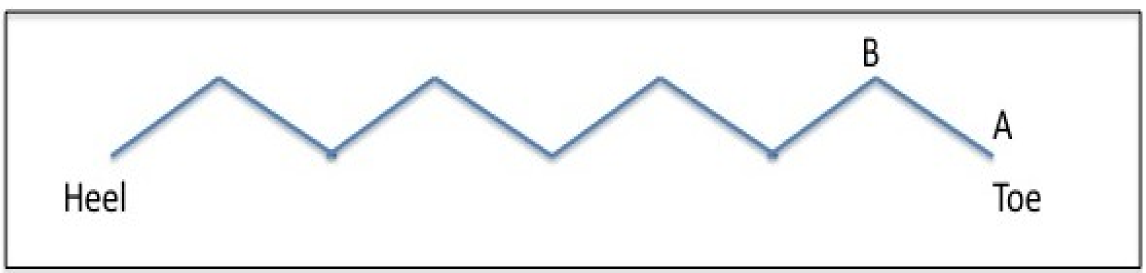

Figure 2 Horizontal well trajectory

2.3 Wellbore Model

When fluid (water + gas) flows into a segment of a horizontal well, it travels inside the well from the heel to the toe. Due to this flow from the toe to the heel, pressure drop occurs because of the friction between the pipe and the fluid, and because of potential pressure drop. If the well is horizontal, then the potential pressure drop is zero (Figure 1). But for undulating wells (Figure 2), the flow rate is the sum of downstream flow and local inflow, and the rate increases along the well from the toe to the heel (Figure 1). The potential pressure loss is due to elevation difference between point A and point B. Calculating pressure drop requires the flow rate of gas (q_g) and flow rate of water (q_w).

2.4 Fluid Properties

Fluid properties should be calculated before applying Beggs and Brill (1973) correlation. These properties need to be calculated for each segment. This is because of the continuous change of pressure value along the horizontal well. Gas is a compressible fluid which makes it sensitive to any pressure change.

2.4.1 Gas/Water Interfacial Tension

The surface tension (interfacial tension) between the gas and liquid phases has very little effect on two-phase pressure drop calculations. However, a value is required in calculating certain dimensionless numbers. Empirical relationship for estimating the gas/water interfacial tension was presented by Baker and Swerdloff (1955)

The gas/water interfacial tension at temperatures of 74 ^{o}F and 280 ^{o}F is given by:

$$\sigma_{w(74)} = 75 - 1.108 p^{0.349} \tag{2.4}$$

$$\sigma_{w(280)} = 53 - 0.1048 p^{0.637} \tag{2.5}$$

$\sigma_{w(74)}$: Interfacial tension at 74 ^{o}F (dynes/cm)

$\sigma_{w(280)}$: Interfacial tension at 280 ^{o}F (dynes/cm)

If the temperature is greater than 280 °F, the value at 280 °F is used. If the temperature is less than 74 °F, the value at 74 °F is used. For intermediate temperatures, linear interpolation is used which is presented in the following equation:

$$\sigma_{w(T)} = (75 - 1.108P^{0.349}) + \frac{(T-74)(53-0.1048P^{0.637}) - (T-74)(75-1.108P^{0.349})}{206} \quad (2.6)$$

where:

p: pressure, Psia

T: Temperature, °F

2.4.2 Water Viscosity

Beggs and Brill (1973) presented the following equation:

$$\mu_w = \exp(1.003 - 1.479E10^{-2}T + 1.982E10^{-5}T^2) \quad (2.7)$$

where:

T: Temperature, °F

μ_w: Water viscosity, cp

2.4.3 Water Formation Factor

Water formation Factor is a function of water Pressure and Temperature.

$$B_w = A_1 + A_2 p + A_3 p^2 \quad (2.8)$$

B_w: Water formation volume factor, STB/d

p: Pressure, psia

Where coefficients A_1, A_2, and A_3 are given by the following expression:

$A_i = a_1 + a_2 T + a_3 T^2$ where temperature in °R. (2.9)

The coefficients for equation 2.9 are in Table 2 and Table 3.

Table 2 Water formation factor coefficients for gas-free water

A_I	a_1	a_2	a_3
A_1	0.9947	5.8E10^{-6}	1.02E10^{-6}
A_2	-4.228E10^{-6}	1.8376E10^{-8}	-6.77E10^{-11}
A_3	1.3E^{-10}	-1.3855E10^{-12}	4.285E10^{-15}

Table 3 Water formation factor coefficients for gas-saturated water

A_I	a_1	a_2	a_3
A_1	0.9911	6.35E10^{-5}	8.5E10^{-7}
A_2	-1.093E^{-6}	-3.497E10^{-9}	4.57E10^{-12}
A_3	-5.0E^{-11}	6.429E10^{-13}	-1.43E10^{-15}

Hewlett-Packard H.P. 41C Petroleum Fluids PAC manual, 1982.

2.4.4 Gas Compressibility Factor

The standard correlation that is being used in the industry to calculate gas compressibility factor is Standing and Katz (1942) correlation.

$$T_{pc} = 170.5 + 307.3\gamma_g \tag{2.10}$$

$$p_{pc} = 709.6 + 58.7\gamma_g \tag{2.11}$$

where T_{pc} is pseudocritical temperature in ^oR and p_{pc} is pseudocritical pressure in psia.

Then reduced pressure and temperature are calculated.

$$T_{pr} = \frac{T}{T_{pc}} \tag{2.12}$$

$$p_{pr} = \frac{p}{p_{pc}} \tag{2.13}$$

$$Z = A + (1 - A)EXP(-B) + Cp_{pr}^{D}$$

where

$$A = 1.39(T_{pr} - 0.92)^{0.5} - 0.36T_{pr} - 0.101 \tag{2.14}$$

$$B = P_{pr}(0.62 - 0.23T_{pr}) + P_{pr}^{2}\left[\frac{0.066}{T_{pr} - 0.86} - 0.037\right] + \frac{0.32P_{pr}^{6}}{EXP\left[20.723(T_{pr} - 1)\right]} \tag{2.15}$$

$$C = 0.132 - 0.32\log T_{pr} \tag{2.16}$$

$$D = EXP(0.715 - 1.128T_{pr} + 0.42T_{pr}^{2}) \tag{2.17}$$

2.4.5 Gas Density

Gas density is calculated based on the gas molecular weight, which is related to the gas specific gravity by

$$MW = 29SG \tag{2.18}$$

where

SG: Gas gravity

MW: Molecular Weight

$$\rho_g = \frac{P(MW)}{10.732TZ} \tag{2.19}$$

where ρ_g is gas density, lbm/ft^3

2.4.6 Gas Viscosity

To calculate gas viscosity Lee, Gonzalez, and Eakin (1966*)* correlation is used.

$$\mu_g = 10^{-4} K \exp(X \rho_g{}^{Y}) \tag{2.20}$$

where

$$K = \frac{(9.379 + 0.01607MW)T^{1.5}}{209.2 + 19.26MW + T} \tag{2.21}$$

$$X = 3.448 + \left[\frac{986.4}{T}\right] + 0.01009MW \tag{2.22}$$

$$Y = 2.447 - 0.2224X \tag{2.23}$$

2.4.7 No Slip Liquid Hold Up

The calculation of pressure drop needs the value of water and gas superficial velocity at insitu conditions. The current values of gas and water flow rates are at the standard conditions. Using the water volume formation factor and the conversion factors to convert barrel to ft^3 and day to seconds, the water superficial velocity is calculated. This velocity is not the actual physical velocity of the water inside the well. It is the velocity of water if water is the only phase flowing inside the well. It is very convenient parameter.

$$v_{sw} = \frac{5.615}{86400} \frac{q_w}{A} B_w \tag{2.24}$$

v_{sw}: Water superficial velocity, ft/s

A: Cross sectional area of the horizontal well, ft^2

q_w: Water flow rate, STB/d

While gas velocity is calculated using gas volume formation factor.

$$v_{sg} = \frac{q_g E10^3}{A} \frac{ZT}{T_{sc}} \frac{p_{sc}}{p} \frac{1}{86400} \tag{2.25}$$

v_{sg} : Gas velocity, ft/s

q_g: Gas flow rate, Mscf/d

A: Horizontal well cross sectional area, ft^2

Z: Gas compressibility factor

T_{sc}: Temperature at standard conditions, 460 ^oR

p_{sc}: Pressure at standard conditions, 14.7 psia

The mixture velocity of the flow is simply the summation of both velocity the gas and the water.

$$v_m = v_{sl} + v_{sg} \tag{2.26}$$

v_m : Mixture velocity, ft/s

Liquid hold up is describing the relationship between the two phases flowing inside the well. For example, if the flow inside the pipe is 50% liquid and 50% of the flow is gas. This does not mean the liquid is occupying 50% of the pipe volume and this is due to the differences in densities. Liquid hold up is used in Beggs and Brill correlation and many other correlations. Another parameter used in pressure drop calculation is input fraction of the liquid phase which simply means the percentage of the liquid in the flow. The input fraction of the liquid phase is called no slip liquid hold up.

$$\lambda_l = \frac{v_{sl}}{v_m} \tag{2.27}$$

λ_l : Input fraction of the liquid phase (No slip liquid holdup)

2.5 Determining Flow Patterns

The following parameters need to be calculated to determine the flow pattern.

$$L_1 = 316\lambda_l^{0.302} \quad (2.28)$$

$$L_2 = 0.0009252\lambda_l^{-2.4684} \quad (2.29)$$

$$L_3 = 0.1\lambda_l^{-1.4516} \quad (2.30)$$

$$L_4 = 0.5\lambda_l^{-6.738} \quad (2.31)$$

$$N_{FR} = \frac{v_m^2}{gd} \quad (2.32)$$

Where d is inside horizontal well diameter in ft, N_{FR} is Froude mixture number, and G is acceleration of gravity which is 32.2 ft/s^2.

v_m: Mixture velocity, ft/s

Segregated flow exists when the following conditions are satisfied:

If $\lambda_l < 0.01$ and $N_{FR} < L_1$

Or $\lambda_l \geq 0.01$ and $N_{FR} < L_2$

Intermittent flow occurs when

If $0.01 \leq \lambda_l < 0.4$ and $L_3 < N_{FR} \leq L_1$

Or $\lambda_l \geq 0.4$ and $L_3 < N_{FR} \leq L_4$

The conditions for distributed flow are

If $\lambda_l < 0.4$ and $N_{Fr} \geq L_1$

Or $\lambda_l \geq 0.4$ and $N_{FR} > L_4$

And finally transition flow occurs when $\lambda_l \geq 0.01$ and $L_2 < N_{FR} \leq L_3$

2.6 Calculating Liquid Hold Up

Beggs and Brill correlation has been developed originally for horizontal wells (inclination angle is zero). Later on, the correlation has been modified to accommodate different inclination angles. Even though the liquid holdup has been modified for the different inclination angles, the flow pattern is the same. In other words, the flow pattern from Beggs and Brill correlation is always based on horizontal well with angle equal to zero. The flow pattern has not been modified to accommodate the different inclination angle. For perfectly horizontal pipes, the holdup at zero-degree deviation for different flow patterns is summarized as following.

Segregated Flow

$$H_{L(0)} = \frac{0.98\lambda_l^{0.4846}}{N_{FR}^{0.0868}} \tag{2.33}$$

Intermittent

$$H_{L(0)} = \frac{0.845\lambda_l^{0.5351}}{N_{FR}^{0.0173}} \tag{2.34}$$

Distributed

$$H_{L(0)} = \frac{1.065\lambda_l^{0.5824}}{N_{FR}^{0.0609}} \tag{2.35}$$

Transition

$$H_{L(0)Transition} = AH_{L(0)segregated} + BH_{L(0)\mathrm{int}ermittent} \tag{2.36}$$

$$A = \frac{L_3 - N_{FR}}{L_3 - L_2} \tag{2.37}$$

$$B = 1 - A \tag{2.38}$$

Once the liquid holdup is calculated for zero-degree horizontal, the actual liquid holdup for inclined well can be obtained by multiplying the $H_{L(0)}$ with modification factor called inclination factor B(θ).

$$H_{L(\theta)} = B(\theta) H_{L(0)} \tag{2.39}$$

$$B(\theta) = 1 + \beta \left[\sin(1.8\theta) - \frac{1}{3} \sin^3(1.8\theta) \right] \tag{2.40}$$

If β is < 0 then set β to zero value

Where B(θ) is inclination factor, dimensionless; $H_{L(0)}$ is horizontal liquid holdup, dimensionless; $H_{L(\theta)}$ is modified liquid holdup for different inclination angles β is Beggs and Brill coefficient, dimensionless; and θ is angle of inclination from the horizontal in degrees

β is a function of flow pattern, the direction of inclination of the pipe (uphill flow or downhill flow), the liquid velocity number (N_{vl}), and the Froude Mixture Number (N_{FR}) . N_{vl} is defined as:

$$N_{vl} = 1.938 v_{sl} \left[\frac{\rho_l}{\sigma} \right]^{0.25} \tag{2.41}$$

where

v_{sl}: Superficial liquid velocity, ft/s

N_{vl}: Liquid velocity number, dimensionless

ρ_l : Liquid density, lb/ft^3

σ: Gas/liquid surface tension, dynes/cm

For uphill flow, Beggs and Brill coefficient can be calculated for different flow patterns as following.

Segregated

$$\beta = (1-\lambda_l)\ln\left[\frac{0.011 N_{vl}^{3.539}}{\lambda_l^{3.768} N_{FR}^{1.614}}\right] \tag{2.42}$$

Intermittent

$$\beta = (1-\lambda_l)\ln\left[\frac{2.96 \lambda_l^{0.305} N_{FR}^{0.0978}}{N_{vl}^{0.4473}}\right] \tag{2.43}$$

Distributed flow has a zero value for β.

For downhill flow, β can be calculated for all flow patterns as following.

$$\beta = (1-\lambda_l)\ln\left[\frac{4.7 N_{vl}^{0.1244}}{\lambda_l^{0.3692} N_{FR}^{0.5056}}\right] \tag{2.44}$$

If β has a negative value, assume β = 0.

2.7 Gravitation Pressure Drop

Using liquid holdup, in-situ average density is calculated in order to calculate gravity pressure drop between 2 points. For example point A(toe) and point B for the first segment.

$$\overline{\rho} = H_{L(\theta)}\rho_l + (1-H_{L(\theta)})\rho_g \tag{2.45}$$

$$\frac{\Delta P_{PE}}{L} = \frac{\overline{\rho}}{144}\sin\theta \tag{2.46}$$

$\overline{\rho}$ is insitu average density in lbm/ft^3, $\frac{\Delta P_{PE}}{L}$ is potential energy pressure gradient in psi/ft, and θ is angle of inclination from the horizontal in degrees.

2.8 Frictional Pressure Drop

To calculate frictional pressure drop, input fraction weighted density and viscosity are determined first.

$$\rho_m = \lambda_l \rho_l + (1-\lambda_l)\lambda_g \tag{2.47}$$

$$\mu_m = \lambda_l \mu_l + (1-\lambda_l)\mu_g \tag{2.48}$$

Reynolds number should be calculated to determine the friction factor.

$$N_{\mathrm{Re}m} = 1488\frac{\rho_m v_m d}{\mu_m} \tag{2.49}$$

The density used to calculate Reynolds number is mixture density which can be called noslip density. For noslip friction, explicit Chen equation (Chen, 1979) is used.

$$\frac{1}{\sqrt{f_f}} = -4\log\left\{\frac{\varepsilon}{3.7065} - \frac{5.0452}{N_{\mathrm{Re}}}\log\left[\frac{\varepsilon^{1.1098}}{2.8257} + \left(\frac{7.149}{N_{\mathrm{Re}}}\right)^{0.8981}\right]\right\} \tag{2.50}$$

The two phase friction factor can be calculated by:

$$f_{tp} = f_n e^s \tag{2.51}$$

x is noslip liquid holdup to liquid holdup ratio.

$$x = \frac{\lambda_l}{H_L^2} \tag{2.52}$$

If 1< x < 1.2

$$s = \ln(2.2x - 1.2)$$

Otherwise

$$s = \frac{x}{-0.0523 + 3.182x - 0.8725x^2 + 0.01853x^4} \tag{2.54}$$

Pressure drop due to friction per length unit is calculated by:

$$\frac{dp_f}{L} = \frac{2 f_{tp} \rho_m {v_m}^2}{144 g d} \tag{2.55}$$

$$Total.\Pr essure.Drp = \frac{\left(\frac{\Delta P_{PE}}{L} + \frac{dp_f}{L} \right)}{1 - E_k} L \tag{2.56}$$

$(1 - E_k)$ term accounts for acceleration contribution to pressure drop.

$$E_k = \frac{v_m v_{sg} \rho_m}{g_c p} \tag{2.57}$$

2.8 Integrated Model for Horizontal Well Performance

In the previous sections of this chapter, a reservoir inflow model and a wellbore pressure drop model are presented. Understanding that the two models provide the main equations to relate reservoir inflow rate and the wellbore flowing pressure, an integrated procedure is presented to generate the flow profiles for a system described in Figure 2.

To start the calculation procedure, we first separate the well in Figure 1 into several sections by the change of the angle (ups or downs). For example, the well in Figure 1 wills be8 sections. Next, from the toe to the heel, we further divide the sections into several segments. On each segment the wellbore flowing pressure, is calculated from flow in wellbore by Beggs and Brill's model based on a given upstream pressure (for example, pressure at point A).

The Babu and Odeh's model is used to calculate flow rate from the reservoir based on p_{wf}. Once the local flow rate is estimated, the rate is added to upstream rate to calculate the pressure drop.

For each segment, these steps describe the process:

1- Calculate gas and water flow rates at point A using equations (2.1) and (2.3).

2- Calculate pressure drop due to friction and potential using the equations in this section.

3- $P_B = P_A$ – Pressure drop for the first segment

4- Calculate the new gas and water flow rates at point B using equations (2.1) and (2.3) with P_B.

5- Now, add $q_{gA} + q_{gB}$ and $q_{WA} + q_{wB}$.

6- Using the accumulated flow rates, pressure drop is calculated using the equations in this section.

7- And so on. For every pressure drop calculation, the accumulated flow rates are used.

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CHAPTER III

RESULTS AND DISCUSSION

In this chapter, the effect of wellbore trajectory and water flow rate on gas well production is examined by using the model and methodology presented in previous chapters. We will study three parameters, the inclination angle of horizontal wells from perfectly horizontal, the length of each undulation section, and the water flow rate. The water flow rate is calculated from GWR, thus, GWR is used as a parameter.

3.1 Reservoir and Well Overview

There will be four cases in this chapter. All these cases use the same reservoir descriptions. Table 4 shows gas reservoir parameters. Using these properties, gas flow rate can be calculated. Table 5 contains well characteristics that are common for the three cases.

Table 4 Gas reservoir properties

Reservoir pressure, psia	6,000
k_v, md	0.01
k_h, md	0.10
Reservoir width, a, ft	500
Reservoir height, h, ft	100
Drainage area, A, ft^2	50,000
Skin factor, s	0
Compressibility, z	0.9
Gas viscosity, μ_g, cp	0.017
Reservoir temperature, ^oF	210
Gas specific gravity	0.6
Water density, lbm/ft^3	62.4
Reservoir depth, ft	10,000

Table 5 Well characteristics

Toe pressure, psia	5,000
Well inside diameter, in	2.259
r_w, ft	0.25
Roughness	0.0006
Well length, ft	5,000

3.2 Case One

The horizontal well is 5000 ft long (from heel to toe). Starting from the heel, the well is deviated upward for 500 ft with positive angel then downward for 500 ft with a negative angel. This will result a horizontal well consists of 10 segments each one of them is 500 ft and the total length is 5000 ft. The overall shape is displayed in Figure 1. As for water flow rate, GWR of 18 Mscf/STB is used to calculate water flow rate. Summary of case one is illustrated in Table 6.

Table 6 Summary of case one

Horizontal well trajectory	500 ft goes up (+degree) then 500 ft goes down (- degree)
Number of sections	10
Total well length	5000 ft
Flow rate	Equation (2.1) and (2.3) are used to calculate gas and water flow rates where L in (2.1) is 1 ft
Pressure drop	Beggs and Brill's correlation

The sections of 500ft are further divided into smaller segments. We first use 1ft segment. In Table 5, every 500 ft segments are cut into 1 ft because of two reasons. In pressure drop calculation, fluid properties are very important. Fluid properties change with pressure so instead of using an average pressure for a long segment which may lead to inaccurate pressure drop calculation, a small segment is tested. In 1ft long segment, fluid properties are not going to change significantly.

3.2.1 Flow Rate Results

To examine the inclination angle effect, we used three different angles in this case, 1 degree, 2 degree, and 0 degree (perfectly horizontal). After all the required calculations, the results are displayed in Table 7 and graphically in Figure 3. From Table 6 we can see that there are no significant differences between the three trajectories. This is due to the small segment used in the calculation combined with the well trajectory and flow rate. When the segment is small, in pressure drop calculation, the pressure drop may be too small (proportional to the length) truncated. Since the calculation is in a discontinued manner, one segment does not add the physical effect of the previous segments like water buildup. This will be investigated more in case two in which the 500ft segments will be cut into 100ft instead of 1ft.

Table 7 Results summary for case one

Trajectory angle, degree	2	1	0
Total pressure drop, psia	452	450	448
Total gas flow rate, Mscf/d	19,234	19,214	19,197
Total water flow rate, STB/d	1,069	1,067	1,066

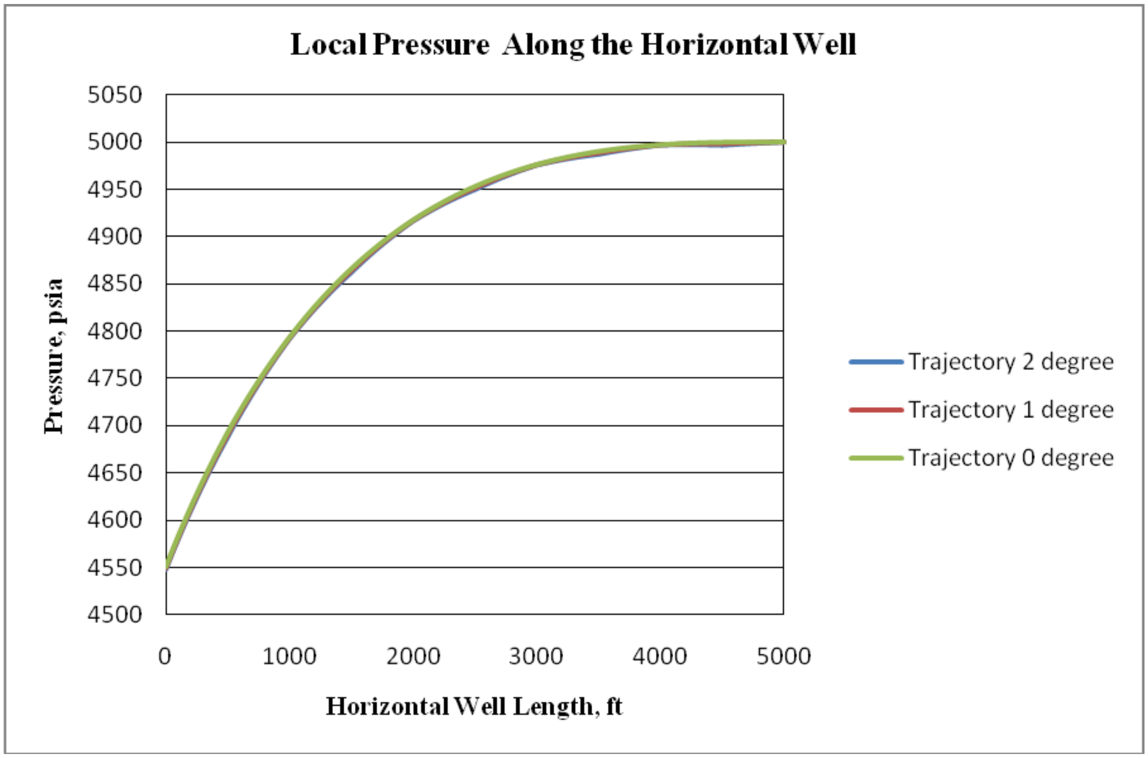

Figure 3 Pressure drop along the horizontal well

We also observed that as inclination angle increase, the total pressure in each section increased slightly. This is because even potential energy does not change if the elevation is the same, the energy does not fully recover when the flow goes up and down. Frictional pressure drop consume more energy when the section goes up than when it goes down in two phase flow. This could lead to a significant pressure drop along the wellbore if the well length is long, flow rate is high, or/and the well diameter is small.

3.2.1 Pressure Drop Components

Calculating pressure drop involves the calculation of pressure drop due to friction, gravitation, and acceleration. Adding all three components results the total pressure drop shown in Figure 4.

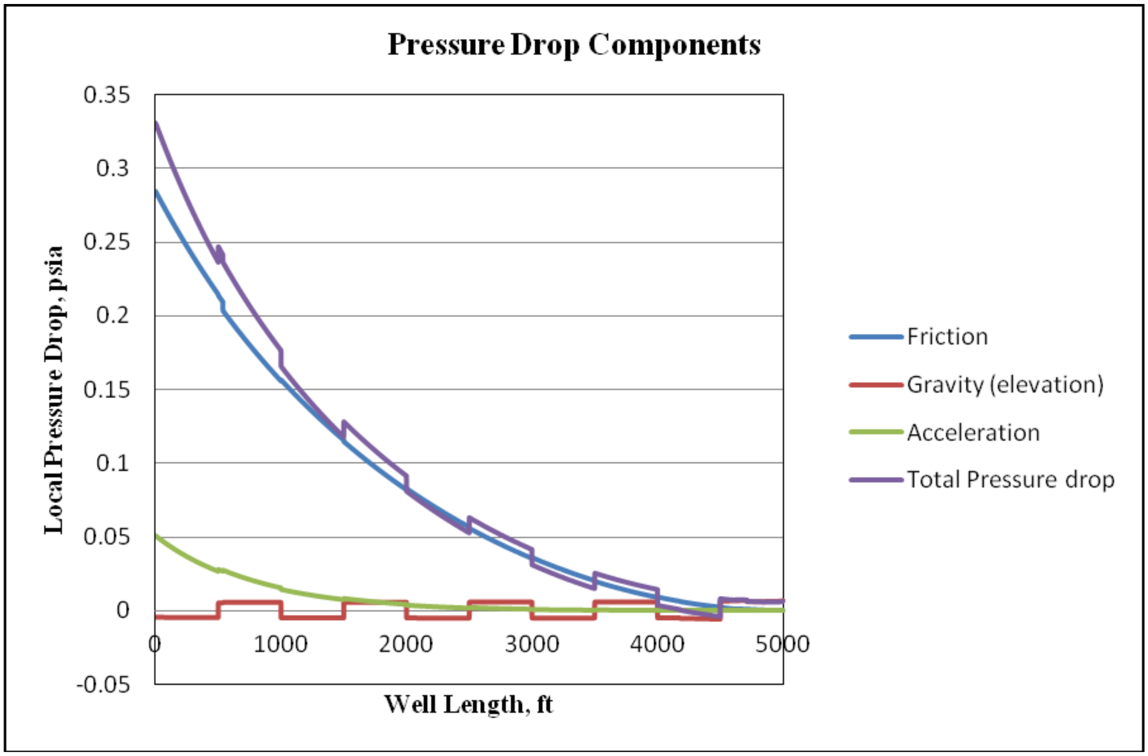

Figure 4 Pressure drop components contribution in the total pressure drop

It can be seen from Figure 3 that pressure drop components contribute defrerently in the total pressure drop. Firction is the main contributer which was expected since the main fluid flowing in the horizontal well is gas. Gas has high velocity which results in higher pressure drop due to friction. When the well is deviated up or down, pressure drop due to friction is not reduced. We observed that as flow rate increases along the well, frictional pressure drop increases with a positive slop. Since gas is a light fluid, gravity does not play any role in pressure drop, and when the elevation ends the same, gravitation change because of going up or down is almost cancled. As for acceleration component, it has a little effect in all pressure drop caculation unless the fluid travels at a high velocity. Acceleration component starts to effect at later stage when gas and water flow rates increase and start to travel at high velocity.

3.4 Case Two

In this case, the 5000 ft horizontal well consists of 20 segments each one of them is 250 ft. The trajectory angel will be 1, 2, and 3 degree. The rasults are illustrated in Table 8.

Table 8 Case two summary

Degree	1	2	3
Total pressure drop, psia	450	451	453
Total gas flow rate, Mscf	19,207	19,218	19,232
Total water flow rate, STB/d	1,067	1,068	1,068

In this case, the horizontal well has more deviations than the first case. In real life this could have more effect than case one because of elbows number. In any fllowing pipe the elbow is a crtitical point for the fluid since it lose more pressure due to friction and the sudden change in fluid dirction. In addition, those areas are places for water accumulation.

3.5 Case Three

In this case, water flow rate effect on pressure drop is investigated. We will study the sensitivity of this matter. In other words, could a small increase in water production kill the well? Using 5000 ft horizontal well consists of 250ft segment cut into 1ft with 3 degree trajectory, Figure 5 is generated.

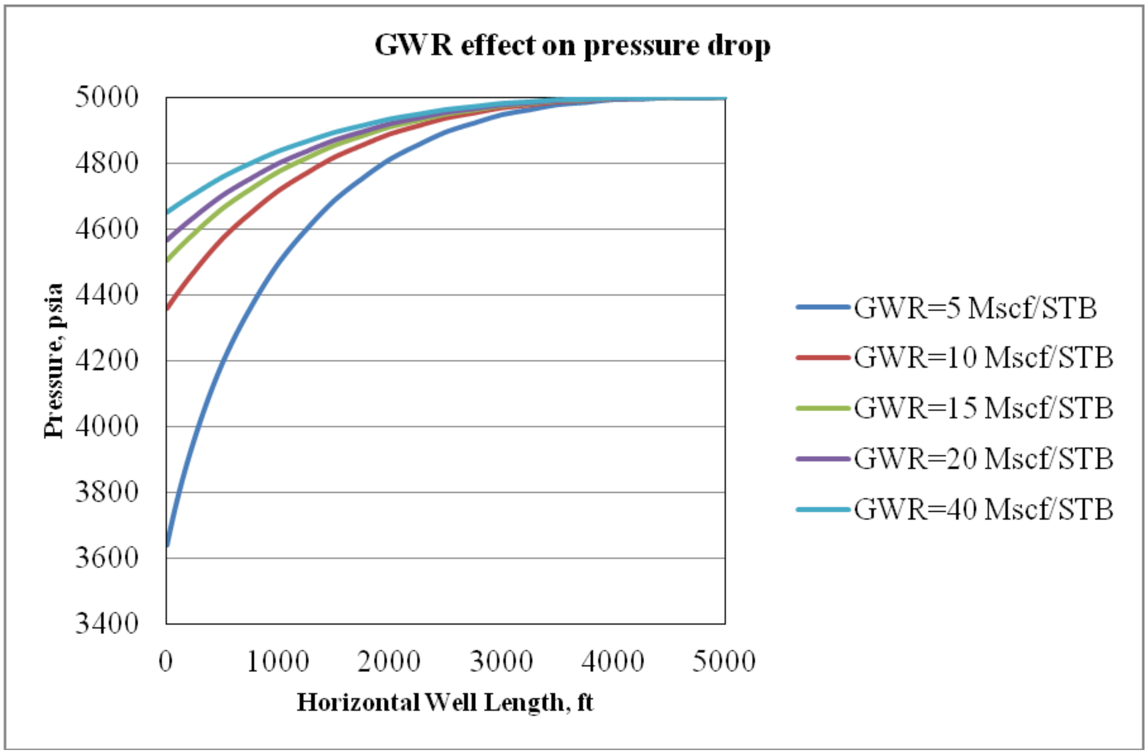

Figure 5 Gas water ratio effect on pressure drop

From Figure 5, at a position of 2,000 ft a way from the heel, water imblication starts to reflect strongley on pressure drop. The effect of water is exponential. For the studied GWR, when GWR is higher than 10 Mscf/STB, the results are in an acceptable pressure drop range. However, when GWR is equal to or less than 5 Mscf/STB water production will kill the well.

CHAPTER IV

CONCLUSION

In this research, we tried to understand the horizontal well trajectory and the effect of water on this system but few has been illustrated in chapter 3. Based on the assumptions, equations, and correlations which have been used in this research, the followings are concluded.

1- It is true that horizontal well trajectory cannot be controlled 100% but as long as the horizontal well has symmetric shape, trajectory has a minimum effect of pressure drop. In other words, if a horizontal well deviated up for some distance, it should be deviated down with the same distance and angel to minimize pressure drop.

2- Trajectory angels have no effect on horizontal wells. If fluid travels up, lose more pressure than going down but flowing downwards let fluid gains some pressure due to gravity effect. This should not be understood as both scenarios cancel each other. The effect of friction is still there and playing a very important role.

3- Pressure drop is due to friction, gravity, and acceleration. Those three elements have unique effect on pressure drop. Decreasing the effect of one of them could increase the other ones. Flow starts to build up gradually starting with a small gas and water flow rates at the toe and end up with huge flow rate at the heel. At first gravity effect is dominating due to low gas flow rate.

As soon as the gas flow rate increase, friction effect becomes dominating. Near the heel point, acceleration starts to have a noticeable effect on total pressure drop.

4- Water flow rate should be monitored closely. A small increase in water flow rate could lead to killing the well. Even with the huge amount of gas which can decrees the density of the overall fluid mixture, still water has a powerful effect on pressure drop. Water is the heaviest fluid in reservoir as soon as it starts to move pressure drop due to gravity starts to build up. Not to mention, water can easily be left by gas at the elbows of the horizontal well chocking the path in front of the gas.

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