2014

Impact of gas desorption on production behavior of shale gas

Fatemeh Belyadi

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IMPACT OF GAS DESORPTION ON PRODUCTION BEHAVIOR OF SHALE GAS

Fatemeh Belyadi

**Dissertation submitted to the
College of Engineering and Mineral Resources
at West Virginia University**

in partial fulfillment of the requirements for the degree of

**Doctor of Philosophy in
Petroleum and Natural Gas Engineering**

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Petroleum and Natural Gas Engineering

Morgantown, West Virginia

2014

**Keywords: Adsorption, Hydraulic fracture, Natural fracture, Shale gas
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ABSTRACT

Impact of Gas Desorption on Production Behavior of Shale Gas

Fatemeh Belyadi

Ultimate recovery in an unconventional gas reservoirs is typically less than conventional gas reservoirs because the adsorbed gas is not consistently taken into consideration. As a result, it is important to study the effect of desorption on production behavior of the shale gas reservoirs in order to improve the recovery of hydraulically fractured horizontal wells.

This dissertation summarizes the results of a modeling study to evaluate the impact of gas desorption on production behavior of multi-fracture horizontal well completed in a shale formation. A numerical reservoir simulator was utilized to generate the production profiles for a multiple fractured horizontal well in shale formation counting both fissures and adsorbed gas. The simulation results were then used to investigate impact of the formation properties, hydraulic fracture characteristics, and desorption characteristics on adsorbed gas recovery. The formation properties that were studied included matrix and fissure porosity and permeability as well as Langmuir concentration and diffusivity coefficient. In addition, the impact of gas desorption on flow regimes and production decline behavior of the hydraulically fractured horizontal wells were studied.

It was concluded that desorption can contribute an additional 18 percent to total gas recovery. However, the recovery factor for the adsorbed gas is much lower than the recovery factor for the free gas. Among all the parameters that were studied, the number of the hydraulic fracture and the fissure permeability were found to have significant impacts on both the recovery of free gas and the recovery of the adsorbed gas in the shale gas reservoirs. Gas desorption was found to have minor impacts on the flow regimes and decline behavior of the hydraulically fractured horizontal shale wells.

ACKNOWLEDGEMENTS

To begin, I would like to sincerely thank all those individuals who provided me the countless opportunities to thoroughly complete this dissertation. My deepest gratitude goes to all my family and friends for their love and support over the course of my studies spanning several years. My mother and father have been the pivotal foundation of inspiration for me. I dedicate this work to my loving parents. With heartfelt appreciation I would like to thank them both for being constantly supportive, patient, and my best friends. I also dedicate all my work and efforts to my older brother who sadly passed away 16 years ago. Above all, I greatly appreciate God for giving me this tremendous opportunity to successfully complete this segment of my academic endeavors

Dr. Aminian, my research advisor, is someone I would like to greatly thank and acknowledge for introducing me to this topic and for his unwavering guidance and mentoring. I have gained so much knowledge and insight from his earnest approach of conducting research. It goes without saying that I am thankful to Professor Sam Ameri, Chairman of the Petroleum & Natural Gas Engineering Department, who has been a crucial role model for me during my entire studies at West Virginia University. I will always be indebted to Dr. Ameri for his vital support and tremendous advising throughout the various academic challenges along the way.

The essential guidance I received from all the various members of this defense panel was vital for the success of my entire research. My gratitude extends to each and every one of them for all the efforts they made on my behalf. Special thanks go to Dr. Ilkin Bilgesu, for all of his countless hours of help and support during my educational stay at WVU. I am also thankful to Dr. Bilgesu for his outstanding participation in the examining committee. I also want to sincerely thank Dr. Pramod Thakur for his participation in the examining committee and his faithful support during my graduate study at WVU. I want to thank Dr. Alan Brannon for his participation in the examining committee and his constant support and guidance throughout my undergraduate study at WVU.

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NOMENCLATURE

V = matrix cell bulk volume.

PV = pore volume

S_o, S_w, S_g = oil, water, and gas saturations

B = formation volume factor, RB/STB

V = ratio of total volume of one porous system to bulk volume

C = wellbore storage coefficient

L_m = fracture spacing

h = thickness, ft.

ϕ = porosity, fraction of bulk volume

L_m = viscosity, cp

k = permeability, md

r_w = wellbore radius, ft.

r_e = external boundary radius, ft

w_f = fracture width, in

x_f = fracture half length, ft

b = hyperbolic exponent

p_i = initial pressure, ft.

p_{wf} = buttonhole flowing pressure, psia (kpa)

G_i = initial gas in place, surface measure

G_p = cumulative gas production, standard cubic feet

q = flow rate, MSCF/D

q_{Dd} = dimensionless flow rate

q_i = initial flow rate, MSCF/D

t = time, years

t_D = dimensionless time

c_t = total compressibility, psi^{-1} (pa^{-1})

D = nominal exponent decline rate, 1/time
 D_i = initial nominal decline rate ($t=0$), 1/time
 e = base of natural logarithms, (2.718...)

Q_D = dimensionless cumulative production

γ_g = gas specific gravity, dimensionless

k_v = vertical permeability (md)

k_h = horizontal permeability (md)

p_p = pseudo-pressure (psia²/cp)

r_{wD} = dimensionless wellbore radius

T = temperature (°R)

d_i = initial decline rate L³/t, RB/D

q_t = production rate at time t L³/t, RB/D

R^2 = Regression coefficient

SSE = Sum of squares of errors in measured data

SST = Total sum of squares of measured data

x = independent variable

y = dependent variable

G_{st} = total gas storage capacity

G_f = free gas storage capacity, scf/ton

G_{so} = solution gas in oil storage capacity, scf/ton

G_{sw} = solution gas in water storage capacity, scf/ton

G_{sl} = Langmuir storage capacity, scf/ton

Q = heat of sorption (j/kmol)

R = universal gas constant (8314 j/Kmol -°K)

V = Gas content (SCF/Ton)

V_m = Maximum sorption capacity (SCF/ton)

b = Langmuir constant (KPa-1) or (Psia-1)

p = pressure (kpa) or (psia)

SUBSCRIPTS

a =adsorbed gas

f = fracture

m = matrix

$f+m$ = total system

1. Introduction

One important feature that makes unconventional shale gas reservoir unique compared to conventional resources is the way gas is stored in shale formation. In conventional gas reservoirs, only free gas is present. In contrast, gas is stored in the shale both as free gas within pores and natural fracture as well as adsorbed gas attached to the organic and mineral surface (Agbaji et al., 2009).

To release the adsorbed gas, it is often necessary to significantly lower the reservoir pressure. However, most shale formations are characterized by ultra-low matrix permeability. Therefore, it is not practical to lower the reservoir pressure by conventional completion and production techniques. The application of multi-stage hydraulic fracturing treatments in horizontal wells has unlocked considerable reserves of hydrocarbons contained in the heterogeneous, ultra-low permeability unconventional reservoirs such as Middle Devonian Marcellus Shale of the northern Appalachian Basin.

In the shale gas reservoirs, the gas in fractures is produced first. Once the gas within the fractures have been produced, gas production rates decline rapidly, and the rate of decline depends on reservoir properties. Upon gas desorption, the decline rate tends to slow down. However, the effect of gas desorption on the production decline behavior has not been studied. Belyadi (2011) investigated the impact of different reservoir characteristic on production behavior of the hydraulically fractured horizontal wells in shale gas reservoirs. They concluded that during the early stages of production, gas desorption had a negligible impact. Their study however did not consider the long-term impact of gas desorption on production behavior. Nelson, et al. (2014) investigated the long term production performance of Marcellus shale using decline curve methods without extensively studying and comparing a model that considers adsorbed gas versus another model that eliminates the presence of adsorbed gas.

Ultimate recoveries in unconventional gas reservoirs are often underestimated as compared to conventional reservoirs because the additional recovery from the gas desorption is not consistently considered. In order to improve the evaluation of the gas recovery from hydraulically fractured horizontal wells in shale gas reservoirs, it is important to investigate the impact of the gas desorption on production behavior. Therefore, the goal of this study is to determine how the gas desorption impacts the production decline behavior and gas recovery from the shale reservoirs. Furthermore, to determine the impact of reservoir and the hydraulic fracture characteristic on the gas desorption.

2. Literature Review

Unconventional shale gas reservoirs have become extremely important with the development of multi-stage hydraulic fracturing which utilizes water, proppant, and other chemicals to fracture the rock at high rate. The development of multi-stage hydraulic fracturing in recent years has made unconventional shale reservoirs to be economically feasible to produce. The EIA (2011) estimates that the shale gas in place is about 750 Tcf. Shale gas can be found in three regions; Northeast, Gulf coast and Southwest region which accounts for 63%, 13% and 10% of total recoverable gas resources respectively (See Figure 2.1). The biggest gas plays are Marcellus (410.3 Tcf), Haynesville (74.4 Tcf), and Barnett (43.4 Tcf). (EIA, 2011)

Figure 2.1: Shale Gas distribution in lower 48 states (EIA, 2011)

Marcellus shale found in the Appalachian basin is located in Northeastern part of the country, represents the largest unconventional gas resource in the United States. The states that Marcellus shale are distributed are listed in table 2.1 (USGS, 2002).

Table 2.1: Distribution of Marcellus shale in various States (USGS, 2002).

State	Areal percentage of Marcellus
Maryland	1.09
New York	20.06
Ohio	18.19
Pennsylvania	35.35
Virginia	3.85
West Virginia	21.33

Marcellus shale is organic rich sedimentary rock which formed during the Devonian period. The organic content was preserved when the Shale gas was deposited in an anoxic deep water environment. Organic content of shale is essentially transformed into natural gas. Natural gas in shale gas is stored in organic matter, natural fracture, and pore spaces, and it occupies larger geographical area as opposed to conventional reservoir that is gas stored in trap. Figure 2.2 shows the distribution of Marcellus shale with surrounding formations (Lee D.S. et al., 2011).

Marcellus shale has the area of 140,000 square kilometers in the Appalachian basin. The depth of the shale usually ranges from 4,000 to 8,500 feet, and its thickness ranges from 50 to 200 feet. The thickness of Marcellus shale is increasing toward the east as illustrated in Figure 2.2 (Lee D.S. et al., 2011).

Figure 2.2: Marcellus shale formation isopach (thickness) map (Lee D.S. et al., 2011)

As opposed to conventional reservoirs in which hydrocarbon is migrated from the source rock until trapped, unconventional shale reservoirs such as Marcellus Shale is considered to be the source rock. Shale porosity ranges from 0.1% to 9.28% and its permeability ranges from 2×10^{-7} to 2×10^{-2} md (Refer to Appendix B, for Devonian shale core analysis results (Soeder, D.J., 1988)). The permeability of shale reservoirs is extremely low because of the small pore sizes of the rock. This attribute of shale makes them relatively impermeable to gas flow unless natural fractures exist. Furthermore, horizontal drilling and multi-stage hydraulic fracturing is necessary for these reservoirs to be producing at economically feasible rates (Lee D.S. et al., 2011).

2.1. Adsorption

Sorption is a process in which a gas (liquid-like or condensate phase) held in microspores substance. There are two types of sorption processes; physical and chemical. Physical sorption caused by electrostatic and Vander Walls forces. The chemical sorption (high heat of sorption) is the result of a strong chemical bond (Ruthven, 1984).

As free gas pressure increases, the amount of the sorbed gas will increase, which is referred to as the adsorption process. On the other hand, the desorption process is the result of the sorbed gas reduction as pressure decreases (Bell et al., 1986). Moreover, sorption isotherm defines the equilibrium volume of gas that is adsorbed on a solid surface at constant temperature (Yee et al., 2011). Sorption isotherm is usually used to determine the maximum amount of gas that is adsorbed to the coal when it is fully saturated with the gas. The sorption isotherm can be used to estimate the amount of the gas that is released (recovery) as a function of pressure (Yee et al., 2011).

There are three types of isotherm model; Gibbs, potential theory, and Langmuir (Yang et al., 1987). Gibbs model defines the sorption process by the equation of state in terms of two-dimensional films. Several author including; Sunders et al. (1985), Stevenson et al. (1991) have used this model for the gas sorption in the coal. Potential theory model defines the sorbed volume as a thermodynamic sorption potential. Gibbs and potential theory models mostly were implemented for gas sorption on the coal (Yee et al., 2011).

Langmuir model is defined as the equilibrium between condensation and evaporation. Langmuir model consists of three different types of isotherms; the Langmuir, the Freundlich, and the combination of both (Langmuir and Freundlich) isotherms (Yang, 1987).

Irvin Langmuir (1916) developed theory of Langmuir isotherm and it is the most important model that describes sorption relationship. The main assumptions for deriving the Langmuir equation are as below (Denial et al., 1957):

- In each adsorption site, one gas molecule is adsorbed.
- There is no interaction between adsorbed and gas molecules adsorbed at the neighboring site.
- Adsorption site's energy is equal (homogenous adsorbent).

For a given temperature at equilibrium state, the rate of adsorbed gas molecules is equal to rate of the desorbed gas molecules (Halliburton, 2007):

$$r\theta = K(1 - \theta)p \quad (1)$$

Moreover, by rearranging the equation 1, θ is defined as (Halliburton, 2007):

$$\theta = \frac{(k/r)p}{1 + (k/r)p} \quad (2)$$

Where θ is a fraction of monolayer coverage and K/r can be considered as a constant at any temperature and is defined as (Halliburton, 2007):

$$\theta = \frac{V}{V_{\max}}$$

$$B = k/r$$

Based on the Langmuir theory gas content is defined below (Halliburton, 2007):

$$V = V_m \frac{Bp}{1 + Bp} \quad (3)$$

Constant b is defined as Langmuir constant or reciprocal of Langmuir pressure.

At very low pressure since $(1 + Bp) \approx 1$, Langmuir isotherm becomes: $V = V_m B p$

Then Langmuir isotherm can be rewritten via replacing the B value by $1/P_L$ (Halliburton, 2007):

$$V = V_L \frac{P}{p_L + p} \quad (4)$$

Figure 2.3 Langmuir isotherm model (Langmuir, 1916)

Langmuir volume, V_L or V_m , is defined as the maximum amount of gas held in the coal or shale at infinite pressure. As can be seen in the above graph (Figure 2.3), as pressure increases, the gas content approaches the Langmuir volume. Furthermore, Langmuir pressure, p_L , corresponds to the pressure at which one half of the gas volume is adsorbed (Bell et al., 1986).

Freundlich isotherm is given by equation below (Yee et al., 2011):

$$V = KP^n \quad (5)$$

The combined Langmuir/ Freundlich isotherm is (Yee et al., 2011):

$$V = V_m \frac{KP^n}{1 + KP^n} \quad (6)$$

The isotherm constant is determined by curve fitting the sorption isotherm and experimental data. Equation 4 can be rewritten as below (Halliburton, 2007);

$$\frac{P}{V} = \frac{P}{V_m} + \frac{1}{BV_m} \quad (7)$$

Using linear least square fit technique one could determine constant B and V_m (as slope and intercept). The nonlinear least square technique could also be implemented to fit the Langmuir isotherm equation given above (Yee et al., 2011).

2.2. Initial Gas in the shale reservoirs

Initial hydrocarbon is crucial in determining the economic feasibility of shale gas reservoirs and reserve estimation. In ultra-low permeability reservoirs, such as Marcellus Shale, transient flow regime can last for a long period of time. Therefore, to decrease the uncertainty when performing the reserve estimation, it is important to have the best estimate of hydrocarbon in place (Ibrahim and Wattenbarger, 2006, Ambrose et al., 2011). Figure 2.4 shows the petrophysical model defining the volumetric component of a shale matrix.

Shale gas in place volumes can be expressed using the following equation (Hartman et al., 2011):

$$G_{st} = G_f + G_a \quad (8)$$

Free gas volume (G_f), when corrected for adsorbed gas volume can be expressed by the following (Hartman et al., 2011):

$$G_f = 32.0368 \frac{\phi(1 - S_w) - \phi_a}{\rho_b B_g} \quad (9)$$

Assuming the single fluid system ϕ_a could be defined using below equation (Hartman et al., 2011):

Figure 2.4: Volumetric component of shale matrix (Ambrose et al., 2010)

$$\phi_a = 1.318 \times 10^{-6} M \frac{\rho_b}{\rho_s} G_a \quad (10)$$

Then, the equation for gas volume (single component adsorption isotherm) is defined as (Hartman et al., 2011):

$$G_{st} = 32.0368 \frac{\phi(1-S_w) - 1.318 \times 10^{-6} M \frac{\rho_b}{\rho_s} \left(\frac{G_{sL} p}{p + P_L} \right)}{\rho_b B_g} + \frac{G_{sL} P}{P + P_L} \quad (11)$$

2.3. Hydraulic Fracturing of Shale

Hydraulic fracturing (or frac) is a stimulation technique that has been used in the oil and gas industry for more than sixty years. Unconventional reservoirs such as shale require hydraulic fracturing due to their ultra-low permeability. Hydraulic fracturing is used to improve the connection between the wellbore and the low permeable rock. In 1997, slick water frac was used in Barnett shale located in Texas. Subsequently, most of the industries began using the same technique across the U.S. for various shale plays (Gilleland, 2011).

In slick water frac technique which is also widely used method in unconventional shale reservoirs such as Marcellus Shale, water, sand, and chemicals are used to create complex fracture system, maximize surface area and connect more natural fractures.

The main reason water frac is popularly used in naturally fractured reservoirs such as Marcellus Shale is because high viscosity fluid has no chance in success. In high viscosity fluid system, any created fractures will simply be parallel to natural fractures. Marcellus Shale is full of natural fractures which are the main source of transferring fluid into the wellbore. As more natural fractures are contacted by hydraulic fracturing, better production is gained as well. Low viscosity fluid such as water frac tends to follow natural fractures and creating a complex fracture system. This is one of the main reasons behind water frac being successful in naturally fractured formations such as Marcellus Shale, Barnett Shale, and many other shale plays across the U.S.

Micro-seismic fracture mapping (see Figure 2.5) is a diagnostic technique which is used in the oil and gas industry to measure the hydraulic fracture dimension and frac azimuth and to confirm that hydraulic fractures do not extend beyond the target area. Regardless of all technological advances in fracturing operation, there are still some challenges that industry faces such as stage spacing, cluster spacing, amount of water, and sand to maximize the production in horizontal wells (Gilleland, 2011).

There are two different types of fracturing operations that are implemented in the industry for shale formation which are Stack frac and zipper frac. Stack fracturing is referred to fracturing one stage and waiting for wireline to perforate the next stage of the same well before being able to frac again. In this type of frac, one well is completed at a time. This type of frac is common in exploration area where only one well is located on a pad. Therefore, frac crews pump a stage and wait for wireline to set the plug and perforate the next stage. Once wireline is done setting the plug, perforating, and pulling out of the hole, frac crew will proceed pumping the next stage. This continues until all the stages are completed on the same well. The disadvantage of stack fracturing is time. Zipper fracturing is referred to fracturing a stage on one well while wirelining the other well. Zipper fracturing can be performed on multiple wells at a time. One of the main advantages of zipper frac is saving time and a lot of money by continuously fracturing and perforating. Zipper frac is very common in lot of shale plays such as Marcellus or Barnett. Simultaneous frac is not as commonly used as zipper or stack frac.

In this type of frac, two wells are simultaneously fraced at the same time. This requires lots of coordination and equipment to be onsite. In addition, pad has to be large enough to fit all the frac equipment for this enormous job. The most important application of hydraulic fracturing is to increase the flow rate of the formation fluid going into the wellbore. Not only does the flow rate increases in a naturally fractured formations that have low permeability (or damaged), but also hydraulic fracturing will connect the natural fractures and faults (if exist) in the formation.

In sandstone formations with high permeability where hydraulic fracturing is typically not required, flow of hydrocarbon under overburden pressure will naturally enter into the wellbore after perforation. In contrast in low permeability reservoirs, when the formation is hydraulically fractured, the amount of formation in contact with the wellbore will increase and, as a result the flow rate will increase. Frac stage is referred to the spacing between plug to plug in a vertical or horizontal well. In many formations across the U.S., the horizontal lateral length in a well is divided into many stages to optimize production.

This is why hydraulic fracturing is often referred to multi-stage hydraulic fracturing because each well has many stages depending on the horizontal length of the well, design, and economic calculations. Therefore, the next interesting subject in hydraulic fracturing is the numbers of stages necessary to maximize production in horizontal wells. When hydraulic fracturing started, some companies tried to perform a single stage frac job with no success. The result of a single stage frac job was essentially terrible, and this was when the need for multi-stage hydraulic fracturing started in various formations across the U.S.

Figure 2.5: Microseismic fracture mapping (Halliburton, 2010).

2.4. Dual porosity model

Shale formations are believed to contain fissures (naturally occurring fractures) and as results are often classified as dual porosity systems. The dual porosity system is defined by two overlapping continuum (Figure 2.6): matrix-blocks (low permeability) and fissures (high permeability) (Barenblatt et al., 1960) (also Warren and Root, 1963).

The fissures have sufficient permeability to allow gas to flow to the wellbore. On the other hand, the low permeability matrix blocks cannot provide a direct flow path to the wellbore. In a naturally fractured reservoir (Figure 2.7), there is a convoluted interaction between the fissure and the rock matrix.

Figure 2.6: Natural fracture reservoir (Shi Nie et al., 2011)

Figure 2.7: Dual porosity model scheme (Shi Nie, et al., 2011).

Barenblatt et al. (1960) were the first to develop a mathematical model for the dual porosity system. A bulk fracture medium is defined below (Her-Yuan et al., 2000):

$$V_b = V_{p_1} + V_{p_2} + V_s \quad (12)$$

V_{p_1} = pore volume of matrix blocks,

V_{p_2} = pore volume of fractures,

V_s = solid volume.

Equation (12) can be rearranging in terms of porosity as (Her-Yuan et al., 2000):

$$1 = \phi_1 + \phi_2 + (V_s / V_b) \quad (13)$$

Where

$$\phi_1 = V_{p_1} / V_b \text{ and } \phi_2 = V_{p_2} / V_b$$

Different models have been proposed for naturally fractured reservoirs. They are dual porosity-single permeability model (Figure 2.8) and dual porosity-dual permeability model (Figure 2.9). In dual porosity-single permeability model, the matrix system has no transmissibility and the flow takes place from matrix to fracture system and then from the fracture system to the wellbore. The dual porosity-dual permeability model assumes that matrix and fracture systems are both connected to the wellbore (Shie Nie, 2011).

Figure 2.8: Dual porosity and single permeability flow pattern (Shi Nie, et al., 2011).

Figure 2.9: Dual porosity and dual permeability flow pattern (Shi Nie et al., 2011).

2.5. Flow regimes in shale gas reservoir

Marcellus Shale reservoirs are described by the dual porosity behavior that was developed by Warrant and Root (1963). Horizontal well solution was developed by Rosa and Carvalho (1988) for naturally fractured reservoirs. Kuchuk et al. (1988) noted that in comparison to the vertical wells, horizontal wells have longer storage effect which could be due to longer horizontal wellbores which can contain a larger volume.

Lu et al. (2009) noted that a number of flow regimes can be present in naturally fractured reservoir meanwhile one or more flow regimes could be masked due to skin damage. Diagnostic log-log plot of flow rate and flow rate derivative versus time is a common way which is used to identify the flow regimes in shale gas formation. Linear flow regime is identified by $-1/2$ slope line and bilinear flow regime is recognized by $-1/4$ slope line (Joshi, 2013).

2.5.1. Flow Regimes Associated with the Horizontal Wells

Numerous flow regimes have been defined for horizontal wells. The “radial flow” is the first flow regime that is observed in the vertical direction. This flow regime has a short duration mainly in high vertical permeability and thin reservoirs (see Figure 2.10). Then,

the intermediate flow regime which is a “linear flow” is developed once the pressure pulse reaches upper and lower reservoir boundaries (see Figure 2.11). Before the late “pseudo-radial flow” is observed, the linear flow period is followed by a transition period (see Figure 2.12).

Figure 2.10: Radial flow regime in horizontal wellbore

Figure 2.11: Linear flow regime in horizontal wellbore

Figure 2.12: Late pseudo-radial regime in horizontal wellbore

2.5.2. Flow Regimes Associated with the Hydraulically Fracture Horizontal Well

Flow regime orders for multi-stage horizontal wells can be very complex as compared to unstimulated horizontal wells. Ozkan et al. (2009) and Brown et al. (2009) presented the concept of trilinear flow (Figure 2.13) for production behavior of hydraulically fracture horizontal wells in unconventional reservoirs.

They demonstrated that most of the production originates from the inner area which is referred to as stimulated reservoir volume since the matrix permeability is in the range of micro-darcy and below. Trilinear-flow contains three linear flows in three flow regions (Figure 2.13): the created hydraulic fracture, the inner reservoir between the hydraulic fracture, and the area beyond the tip of hydraulic fracture or unstimulated reservoir volume.

Previous studies were done by Belyadi, et al. (2010) and Belyadi, et al (2012) to investigate the flow regimes associated with hydraulically fractured horizontal wells in ultra-low permeability reservoirs. In these studies three sequences of flow regimes were investigated; the initial radial fracture storage flow, the linear flow, and the boundary dominated flow (BDF). Furthermore, they illustrated that the late linear flow or trilinear flow occurs where

the drainage area was extended beyond the tip of the fractures. Moreover, Belyadi et al. (2012) studied production performance of multi-fractured horizontal wells in low permeability reservoirs. Two production periods were identified; the early and late time production period. In their study they concluded that the number and the placement of hydraulic fracture stages are mainly impacting the early time production period. However, the late production period is mainly controlled by the formation characteristics. Joshi and Lee (2013) studied different flow regimes including initial radial-linear flow, formation linear flow, fracture interference flow, trilinear flow and boundary dominated flow. As illustrated in Figure 2.14, interference flow originated at each fracture and moves toward the adjacent fractures.

Figure 2.13 Trilinear flow regime scheme (Ozkan et al., 2009)

Figure 2.14: Fracture interference flow regime

2.5.3. Identification of flow regimes

To better comprehend the production behavior of shale gas reservoirs, diagnostic plots are usually used. In diagnostic plots, the inverse of flow rate and its derivative versus time is utilized to identify the flow regimes. Moreover, derivative values are often calculated using five-point finite difference method (Chaudhry, 2003).

To estimate the derivative values, backward difference (Δt_L), forward difference (Δt_R), m_L , m_R and then the derivative was estimated based on the five-point method as presented by the equation below:

$$\Delta p' = \frac{(m_L \Delta t_R) + (m_R \Delta t_L)}{\Delta t_R + \Delta t_L} \quad (14)$$

$$\text{Where} \quad m_L = \frac{\Delta p_L}{\Delta t_L}, \quad m_R = \frac{\Delta p_R}{\Delta t_R}$$

As it was discussed in section 2.5, several flow regimes can be observed when studying the production behavior in horizontal wells with hydraulic fractures. The first flow regime is early-radial linear (fracture storage flow) takes place in hydraulic fracture plane because of high fracture conductivity. Typically, bilinear flow which is rarely present can be identified using $1/4$ -slope line on log-log plot. Then, the second flow regime is linear flow and can be recognized using $1/2$ -slope line on log-log plot. Sometimes a late linear flow can be observed in unstimulated matrix area beyond tip of the hydraulic fractures which also known as trilinear flow. Finally, boundary effects can be detected using unit slope line.

2.6. Decline Curve Analysis

Decline curve analysis is used to predict the future production of oil and gas fields, and it has been used since 1945. Arnold and Anderson (1908) presented the first mathematical model of decline curve analysis. Cutler (1924) also used the log-log paper to obtain a straight line for hyperbolic decline, so the curve shifted horizontally. Larkey (1925) proposed the least square method to extrapolate the decline curves. Pirson (1935) proposed the loss ratio method and concluded that the production decline curve rate/time has a constant loss ratio. Furthermore, Arps (1945) categorized the decline curve using loss ratio method, and he then defined the rate/time and rate/cumulative production. Moreover, he defined three types of decline curves model: exponential, harmonic and hyperbolic decline curves (Figure 2.15). The hyperbolic decline curve can be considered as a general model, and Exponential and Harmonic decline curves can be derived from it.

The decline curve consists of three parameters [q_i , D_i , and n] that could be found from measured data. Furthermore, the following differential equation was used to define the three decline curve models:

$$d = -\frac{1}{q} \frac{dq}{dt} = Kq^n \quad (15)$$

n = the hyperbolic decline exponent

K = proportionally constant

The three decline equations are defined below;

Figure 2.15: Decline curve production plot scheme (Chaudhry, 2003)

2.6.1. Exponential Decline

The most commonly used method is the exponential method which allows for easier determination of the reserve. Below equations define the rate time and cumulative production rate for exponential decline:

$$q_t = q_i e^{-D_i t} \quad (16)$$

$$Q_p = \frac{q_i - q_t}{D_i} \quad (17)$$

Fetkovich et al. (1980) determined that with hyperbolic decline trend, the future production can be projected with the exponential fit decline model using the last few points. For exponential decline assuming $n = 0$, q_i and D_i can be determined by taking the natural log of both sides of the exponential rate time relationship (equation 16).

$$\ln q_t = \ln q_i - D_i t \quad (18)$$

Next, $\ln q$ vs. t was plotted which gives a straight line with slope of $(-D_i)$ and intercept of $(\ln q_i)$.

2.6.2. Harmonic Decline

A less commonly used decline curve is harmonic decline, where $n=1$. Furthermore, it is used when the plot of $\log t$ vs. Q_p is linear and it is derived from equation 18 which can be modified as:

$$\ln q_t = \ln q_i - \frac{D_i Q_p}{q_i} \quad (19)$$

$\ln q_t$ vs. Q_p can be plotted which gives a straight line of $m=-d_i/q_i$ and $b= \ln q_i$. Furthermore, inverse of rate vs. time could be plotted which gives a straight line of $m=d_i/q_i$ and $b=1/q_i$ using below equation:

$$\frac{1}{q_t} = \frac{1}{q_i} + \left(\frac{D_i}{q_i} \right) t \quad (20)$$

Below equations are rate time and cumulative production rate for harmonic decline curve where $n=1$

$$q_i = \frac{q_i}{(1 + D_i t)} \quad (21)$$

$$Q_p = \frac{q_i}{D_i} \ln \left(\frac{q_i}{q_t} \right) \quad (22)$$

2.6.3. *Hyperbolic Decline*

Exponential and harmonic declines are both specific cases of hyperbolic decline. Additionally, in hyperbolic decline, three parameters (q_i , D_i , and n) should be determined. There are several methods to determine these three parameters: trial and error method, type curve overlays, and mathematical and graphical methods. Slider (1968) and Fetkovich (1980) proposed the type curve overlay methods to determine q_i , D_i , and n . Slider proposed that q_t vs. time could be plotted on semi-log paper (production history). Therefore, by overlapping the group of curves, the values of n and D_i could be estimated. Fetkovich (1980) developed the log-log type curve matching technique for decline curve data. Furthermore, he derived the decline equation which is the combination of rate and material balance equations. He stated that decline curve for a well with constant bottom hole flowing pressure should be applied to finite acting time period or pseudo-steady state.

Long and David (1988) estimated the end part of hyperbolic decline using constant percentage decline. Then, they used an overlay to find the exponent n which was greater than 1. Kelkar and Perez (1988) determined smaller n value ($n < 1$) as opposed to the Long and David method. Fraim and Wattenbarger (1987) expanded Fetkovich's type curve for gas by including the real gas pseudo-pressure and time. They have also concluded that only for early time data, Fetkovich's type curve could be used.

Gentry (1972) plotted two graphs of d_t/t vs. q_i/q_t and Q_p/q_t vs. q_i/q_t for $0 < n < 1$, and then plotted the production decline curve. Furthermore, Gentry and McCray (1978) determined that the heterogeneity of the reservoir affects the " n " value and causes the " n " to be greater than 1. They also proved that relative permeability and fluid characteristics have a significant impact on n , D_i , and q_i values respectively. Statistical approach to decline curve analysis is more precise when compared to a graphical method.

Levine and Prats (1961) proposed non-linear partial-differential equations which are used for solution gas drive reservoirs. McNulty and Knapp (1981) used weighted residuals non-linear regression for decline curve analysis of which is used most often for large data sets.

Towler and Bansal (1993) proposed two methods using linear regression method for decline curve analysis, using the equations 19 and 20. However, their methods did not have repeatable results during the curve fitting. Moreover, the non-linear regression technique could be used to overcome the problem, using the Excel spreadsheet solver module. Furthermore, the below equations were used as developed by Arps:

Note: all n is between 0 and 1

$$q_t = \frac{q_i}{(1 + nD_i t)^{1/n}} \quad (23)$$

$$Q_p = \frac{q_i^n}{(1 - n)D_i} [q_i^{(1-n)} - q_t^{(1-n)}] \quad (24)$$

2.6.4. Power Law Exponential Decline Model (PLE)

Power law exponential (PLE) decline was developed by Ilk et al. (2008) by modifying Arp's exponential decline (Seshadri, 2010). This methodology was developed specifically for tight gas wells to model the decline in a transient period of production data. The Power law exponential decline model is defined below (McNeil, R. et al., 2009):

$$q = \bar{q}_i e^{\left[-D_\infty t - \frac{D_1}{n} t^n\right]} \quad (25)$$

Equation (25) can be reduced to power law loss ratio as defined below:

$$q = \bar{q}_i e^{\left[-D_\infty t - D_1 t^n\right]} \quad (26)$$

PLE method does not consider the b value as a constant value but as a declining function in opposition to Arp's method. Moreover, by using PLE model it is easier to match the

production data in transient and boundary dominated regions without overestimating the reserve (McNeil, R. et al., 2009).

2.6.5. *Stretched Exponential Decline*

Stretched Exponential Decline was suggested by Valko and Lee (2010) and it is equal to the power model by rearranging some variables and eliminating the D_∞ . This model is defined in the equation below:

$$q(t) = q_i \exp \left[- \left(\frac{t}{\tau} \right)^n \right] \quad (27)$$

Where q_i is initial production rate (volume/time) and τ is characteristic time parameter. Cumulative production volume is defined as below Valko and Lee (2010):

$$q = \frac{q_0 \tau}{n} \left\{ \Gamma \left(\frac{1}{n} \right) - \Gamma \left[\frac{1}{n}, \left(\frac{\tau}{n} \right)^n \right] \right\} \quad (28)$$

2.6.6. *Duong Model*

Duong (2011) developed the rate decline analysis for fractured shale reservoirs. In this model the long term linear flow was taken into consideration (Joshi, 2013). This model is defined based on the equation given below:

$$q(t) = q_i t(a, m) + q_\infty \quad (29)$$

Where parameters “a” and “m” are determined by using below equation:

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

q = flow rate, volume/time

a = intercept (log-log plot of $\frac{q}{G_p}$ vs. t)

G_p = Cumulative gas production

Furthermore, a plot of “q” versus “t (a, m)” should provide a straight line with a slope of q_1 and intercept of q_∞ (Duong, 2011):

$$t(a, m) = t^{-m} \exp \left[\frac{a}{1-m} (t^{1-m} - 1) \right] \quad (30)$$

Note: q_∞ can be positive, zero or negative depending on the operating conditions (Kanfar, 2012). A cumulative gas production can be determined used “ q_∞ ” is equal to zero as:

$$G_p = \frac{q_1 t(a, m)}{a t^{-m}} \quad (31)$$

Duong examined different types of wells such as tight, dry and wet gas to prove the accuracy of his model. Also, he found that most shale models have “a” values ranging from 0 to 3 and m values ranging from 0.9 to 1.3. His model gives the reasonable estimation of cumulative production compared to the power law and Arp’s model (Dutta et al, 2014).

2.6.7. Application of the decline curves to horizontal shale wells

Nelson et al (2012) investigated the application of various decline curves to production data from hydraulically fractured horizontal wells completed in a shale formation. They concluded that all the previously mentioned decline curves can be matched to the extended production history (30 years) with the similar accuracies. However, when the available production history is limited, reliable prediction cannot be obtained from any of the decline curve models. The decline curve model parameters need to be adjusted to achieve reliable prediction of the future rates. Considering the simplicity of the Arp’s decline curve model, it is the best method to be used when the decline curves need to be adjusted.

3. Objective and Methodology

3.1. Objectives

The main objective of this study is to evaluate the impact of the adsorbed gas on production behavior of ultra-low permeability formation such as Marcellus shale. More specifically, the objectives of this study are:

1. To evaluate the impact of the formation, desorption, and hydraulic fracture characteristics on gas recovery of horizontal well completed in a shale formation.
2. To investigate the impact of gas desorption on the flow regimes associated with the hydraulically fractured horizontal wells.
3. To determine the impact of gas desorption on production decline behavior.

3.2. Methodology

The following section describes the steps taken to accomplish the objectives stated above.

3.2.1 Objective 1

To evaluate the impact of desorption on gas recovery, a commercial reservoir simulator was used to simulate the production profile for a horizontal well with multiple hydraulic fractures in a multilayer dual porosity system with and without adsorbed gas components. The geometry of the model consisted of 5 layers each with a rectangular drainage area of 4000 feet in length and 2000 feet in width. Moreover, the horizontal lateral is 3000 feet long and is located in the center of the rectangular area in the middle layer (Belyadi, A. et al 2010, Belyadi, H. 2011, and Belyadi, A. et al 2012).

The basic model was defined based on the available field data, along with the production and completion data from Marcellus shale gas wells in Pennsylvania and West Virginia (Belyadi, H, 2011). The missing reservoir parameters were estimated based on the results of the production history matching (See Figure 2-B in the Appendix B) using a commercial reservoir simulators (Larch 2012, Elsgher 2013). Table 3.1 summarizes the key input parameters that were used in the simulator.

Table 3.1: Base model parameters used in the simulation

Reservoir Parameters	
Initial reservoir pressure , psia	3000
Bottom-hole pressure Pwf , psia	500
Depth, ft.	7000
Thickness , ft.	75
Fissure porosity, fraction	0.005
Matrix porosity , fraction	0.05
Fissure permeability, i, j, k, md	0.002,0.002, 0.0002
Matrix Permeability, i, j, k, md	0.0004,0.0004,0.00004
Fracture Spacing, 1/ft ²	0.0073
Water Saturation, fraction	0.15
Hydraulic Fracture Properties	
Half length, ft.	500
Width, in.	0.01
Permeability, md	20000
Porosity, fraction	0.2
Adsorption	
Diffusion Coefficient, ft ² /day	0.34
Sorption Time, day	62
Langmuir Pressure, psia	635
Langmuir Concentration, Mscf/ton	0.089

The base model was used to simulate 30 years gas production profiles while maintaining the constant bottom-hole pressure. To investigate the impact of gas desorption on the gas recovery, the production profiles were generated by including and excluding the adsorbed gas component in the model. The difference in the gas recovery from the two profiles was utilized to determine the contribution of the desorbed gas to production. In addition, the difference in the initial gas in place from two models (with and without adsorbed gas) was used to estimate the initial adsorbed gas in the reservoir. The adsorbed gas recovery factor was determined by dividing gas recovery by the initial adsorbed gas. As result, three separate recovery factors can be defined. The total gas recovery factor, the free gas recovery factor, and the adsorbed gas recovery factor.

A number of formation and hydraulic fracture characteristics including number of the hydraulic fractures, permeability of the hydraulic fracture, matrix porosity, fissure porosity, matrix permeability, fissure permeability, and Langmuir concentration were varied to investigate their impact on the gas production from a horizontal well completed in a shale formation. Table 3.2 summarizes the range of these parameters used in simulation runs.

Table 3.2: The ranges of the parameters that were varied in the reservoir model.

Parameters	Values
Matrix Porosity, fraction	0.02, 0.05, 0.07
Langmuir Concentration, Mscf/Ton	0.05, 0.0889, 0.1
Diffusivity coefficient, cm ² /sec	0.004, 0.011, 0.042, 0.088
Fissure Porosity, fraction	0.002, 0.005, 0.007
Fissure Permeability, md	0.001, 0.002, 0.005, 0.01
Matrix Permeability, md	0.0002, 0.0004, 0.0008
Matrix Number of Fracture	1, 2, 4, 7, 13

3.2.2 Objective 2:

To study the impact of gas desorption on the flow regimes associated with the hydraulically fractured horizontal well, the production profiles generated for various cases were analyzed with aid of the diagnostic plots. The diagnostic plot is a plot of the inverse of the flow rate ($1/q$), obtained from the simulated production profile, and its derivative versus time on log-log scale. The derivative values were estimated by five-point finite difference method described earlier in the literature review section.

The diagnostic plots for cases where the adsorbed gas component was included and excluded in the model were compared to evaluate the impact of gas desorption on the flow regimes. Since the hydraulic fracture stage spacing has a significant effect on the duration of the flow regimes, production profiles for cases with 4 (stage spacing of 1000 feet), 7 (stage spacing of 500 feet) and 13 (stage spacing of 250 feet) hydraulic fracture stages were generated and used to prepare diagnostic plots.

3.2.3 Objective 3:

To study the impact of gas desorption on the production decline behavior of shale gas reservoirs, the simulated production profiles, with and without adsorbed gas component, were matched with Arp's hyperbolic decline curve model. The Arp's hyperbolic decline curve model was considered in this study since the previous investigation had shown that the extended production profile from shale reservoirs can be best matched with hyperbolic decline curve (Nelson, 2012). Previous investigation (Belyadi, A 2011) has revealed the presence of several production periods. First, to understand the production decline behavior of horizontal wells with multiple fracture stages, the extended production profile (30-year) was divided into several periods. Then, the production data in each period were matched with separate hyperbolic decline curve. Afterward, the constants b and Di were determined for each hyperbolic decline curve.

Second, to evaluate the impact of gas desorption on the decline curve constants, Arp's hyperbolic decline model was used. Since the hydraulic fracture spacing highly impacts

the early production (Belyadi, 2011), different fracture spacing of 250 ft. (7 fracture stages) and 500 ft.(13 fracture stages) were implemented in this study. The long term decline constants (n , D , and q_i) were determined by fitting 30 years of production profile (including and excluding the adsorbed gas) with the Arps decline curve model. Then, the long term production profile was truncated after different numbers of years (2, 3, 5...) and fitted to Arps decline curve to find the short term decline constant. Then, the ratio of each constant (n , D , and q_i) to 30 year constant was obtained. Moreover, the ratios of each constant were plotted for different numbers of years (including and excluding the adsorbed gas component) (Mashayekhi, A.et al 2014).

4. Result and Discussion

The following sections describe the results for each objective stated above and the impact of gas desorption on production behavior of ultra-low permeability formation such as Marcellus Shale.

4.1 *Objective 1:*

In this study, in order to demonstrate the impact of gas desorption on the total gas recovery from a horizontal shale gas well, several production profile were generated by including and excluding the adsorbed gas component in the model. Moreover, the impact of different formation, desorption, and the hydraulic fracture characteristic on the recovery of adsorbed gas were studied.

4.1.1 *Impact of Langmuir Concentration on the gas recovery*

Figure 4.1 compares total gas recovery for different Langmuir concentration (m). As can be observed, the total recovery factor decreases as Langmuir concentration increases. Also, it can be observed that during the early production period, Langmuir concentration has a minor impact on the total gas recovery since during this period the production is controlled by the hydraulic fracture. During the middle and late production period, Langmuir concentration appears to have significant impact on the total gas recovery. This is because the initial gas in place increases as the Langmuir concentration increases. However, the desorbed gas recovery is much lower than free gas recovery and as result, the total gas recovery decreases. As can be seen in Table 4.1, as the Langmuir concentration increases from 0 to 0.1 Mscf/Ton, the cumulative gas production increases from 4.2 BCF to 5.07 BCF. Moreover, the initial gas in place increases from 5.7 BCF to 9.3 BCF, which indicates 61% increase in the initial gas in place compared to 20% increase in cumulative gas production. As a result, the total gas recovery factor decreases from 73% to 55% which means 18.3% drop in the total gas recovery factor.

Figure 4.1: Impact of the Langmuir concentration on the total gas recovery from horizontal shale gas.

Table 4.1: Shows the cumulative gas production, initial gas in place, and total gas recovery for different Langmuir concentration

Langmuir Concentration (m)	Total Gas Production (Gp)	Initial Gas in Place (IGIP)	Total Gas Recovery Factor
Mscf/Ton	(BCF)	(BCF)	Fraction
0	4.21	5.77	0.73
0.05	4.65	7.53	0.62
0.089	4.98	8.89	0.56
0.1	5.06	9.28	0.55

4.1.2 Impact of Langmuir concentration on the recovery of adsorbed gas

Table 4.2 shows that as the Langmuir concentration increases, the initial gas in place, the cumulative adsorbed gas production, and the total gas production increase. However, the adsorbed gas recovery factor, as illustrated in Figure 4.2 and summarized in Table 4.3, remain nearly constant. This is primarily because the gas production is controlled by the formation permeability which is very low.

Table 4.2: The cumulative adsorbed gas produced and adsorbed gas in place for the different values of the Langmuir concentration.

Langmuir Concentration	Cumulative Gas production	Initial Gas in Place	Cumulative adsorbed gas produced	Adsorbed gas in place
Mscf/Ton	G_p , BCF	IGIP, BCF	G_{pa} , BCF	IGIP _a , BCF
0	4.21	5.77	0.0	0.0
0.05	4.65	7.53	0.44	1.75
0.089	4.98	8.89	0.76	3.12
0.1	5.07	9.28	0.85	3.51

Table 4.3: The impact of the Langmuir concentration on the adsorbed gas recovery factor

Langmuir Concentration	Adsorbed gas recovery factor
m, MSCF/ton	Fraction
0.05	0.25
0.089	0.25
0.1	0.24

Figure 4.2: Impact of Langmuir concentration on the adsorbed gas recovery factor.

4.1.3 Impact of the the diffusion coefficient on the recovery of adsorbed gas

Figure 4.3 illustrates the impact of the diffusivity coefficient on the adsorbed gas recovery factor. As can be observed, the diffusivity coefficient has a minor impact on the adsorbed gas recovery factor. This is because, the adsorbed gas recovery factor is low.

Figure 4.3: Impact of diffusion coefficient on the adsorbed gas recovery factor from horizontal shale gas.

4.1.4 Impact of fissure permeability on the gas recovery

Figure 4.4 compares the free gas recovery for different fissure permeability, which ranges from 0.001 to 0.01 md. As can be seen, gas recovery increases as fissure permeability increase. During the middle production period, fissure permeability appear to have the most impact on the gas recovery. In the late production period, the gas recovery profiles for different values of the fissure permeability are almost parallel. This indicates that the fissure permeability has less impact during later production period.

Figure 4.5 compares the total gas recovery for different value of the fissure permeability. Comparing graph 4.4 and 4.5, it can be observed the the middle production period is somewhat shorter when the adsorbed gas is present. Also, Table 4.4 illustrates that, as the fissure permeability increases from 0.001 to 0.1 md, the cumulative gas production increases from 4.9 BCF to 5.9 BCF. Moreover, the initial gas in place will remain the same.

This will result in 17% of increase in the recovery factor when gas adsorption is considered ($m=0.089$ Mscf/ton).

Moreover, when the effect of adsorption is excluded, 6 % of increase in the recovery can be observed by increasing the fissure permeability from 0.001 md to 0.1.

Figure 4.4: Impact of fissure permeability on gas recovery from horizontal shale gas without adsorption.

Figure 4.5: Impact of fissure permeability on gas recovery from horizontal shale gas with adsorption component.

As illustrated in Table 4.4, the total gas recovery factor decrease on average by 18%. This shows that when adsorbed gas is present, both gas production and initial gas in place increase. However, the increase in the initial gas in place is higher the increase in gas production which results in reduction in the total gas recovery.

Table 4.4: Compares Cumulative gas production, initial gas in place, total gas recovery factor, and free gas recovery factor for different fissure permeability.

Fissure permeability	Total Gas Production	Free Gas Production	Total Gas Recovery Factor	Free Gas Recovery Factor
md	Bcf	Bcf		
0.001	4.90	4.44	0.50	0.77
0.003	5.32	4.44	0.60	0.77
0.005	5.62	4.63	0.63	0.80
0.007	5.83	4.73	0.66	0.82
0.01	5.96	4.79	0.67	0.83

4.1.5 Impact of Fissure permeability on the adsorbed gas recovery factor

Figure 4.6 shows the results for the adsorbed gas recovery factor, for the fissure permeability ranges from 0.001 to 0.01 md. When the fissure permeability increases from 0.001 md to 0.01 md, the cumulative adsorbed gas production increases from 0.64 BCF to 1.2 BCF, However, there is a slight increase in the adsorbed original gas in place. Furthermore, the adsorbed gas recovery increases from 21% to 37%, which means 17% of the increase in the adsorbed gas recovery factor. As a result, fissure permeability has a positive impact on the adsorbed gas recovery factor (see Table 4.5).

Table 4.5: Shows the results for cumulative adsorbed gas production, adsorbed gas in place and adsorbed gas recovery factor.

Cumulative Adsorbed Gas Produced(30 years)	Adsorbed original gas in place	Adsorbed Gas Recovery Factor
G_{p_a} , BCF	$OGIP_a$, BCF	Fraction
0.64	3.12	20.54
0.88	3.12	28.20
0.99	3.12	31.72
1.10	3.12	35.26
1.17	3.12	37.37

Figure 4.6: Impact of Fissure permeability on the adsorbed gas recovery factor.

4.1.6 Impact of number of hydraulic fracture on the adsorbed gas recovery factor

As can be seen in the Figure 4.7 and Table 4.6, as the number of hydraulic fracture increases from 1 to 13 stages, cumulative adsorbed gas production increases from 0.14 BCF to 0.77 BCF. However, the initial adsorbed gas in place stays the same. Moreover, adsorbed gas recovery factor increases from 4.6% to 25% which means 20% of increase in the adsorbed gas recovery factor. As the result, the number of the hydraulic fracture stages has a significant impact on the adsorbed gas recovery factor.

Moreover, the additional recovery contributed by the gas desorption is 18% for a horizontal well with 13 hydraulic fracture stages. Therefore, the adsorbed gas component should be considered for reliable recovery estimation (See Figure 4.8).

Table 4.6: Shows the results for cumulative gas production, cumulative free gas production and adsorbed gas recovery factor.

Number of Hydraulic Fracture	Cumulative Gas Production (30 years)	Cumulative Free Gas Production (30 years)	Cumulative Adsorbed Gas Produced (30 years)	Adsorbed Gas Recovery Factor
	BCF	BCF	BCF	Fraction
1	2.29	2.15	0.14	0.046
2	2.84	2.62	0.22	0.07
4	3.89	3.56	0.33	0.11
7	4.63	4.01	0.62	0.17
13	4.98	4.21	0.77	0.25

Moreover, the results of impact of matrix, fissure porosity and matrix permeability on the adsorbed gas recovery factor are shown in Appendix A.

Figure 4.7: Impact of number of hydraulic fractures on the recovery of adsorbed gas

Figure 4.8: Impact of gas desorption on the gas production for 13 fracture stages.

4.2 *Objective 2: Impact of desorption on flow regime associated with hydraulic fracture horizontal wells.*

Figure 4.9 shows that several flow regimes associated with hydraulic fracture horizontal wells may be present. At start of production, a dual porosity flow can be seen. Next, short linear flow regime which last for 100-700 days with the slope of $-1/2$ can be observed. Then the interference flow can be observed with the slope of 1.

Figure 4.9: Diagnostic plot of inverse of flow rate (and its derivative) vs. time for four fracture stages (without adsorbed gas component).

Figures 4.9 and 4.10 illustrate the diagnostic plots for a horizontal well with 4 fracture stages for the cases where the adsorbed gas component was included and excluded in the model. The same flow regimes can be observed in both plots. Initially, the radial- linear flow can be observed. The valley in the derivative plot is the manifestation of the dual porosity system. Subsequently, the linear flow and fracture interference flow regimes can be observed. Comparison of the Figures 4.9 and 4.10 indicates that the duration of the both the linear flow and the fracture interference periods are longer when the adsorbed gas component is included in the model.

Figure 4.10: Diagnostic plot of the inverse of the flow (and its derivative) rate vs. time for four fracture stages (with adsorbed gas component).

Figure 4.11 and 4.12 illustrate the diagnostic plots for a horizontal well with 7 fracture stages for the cases where the adsorbed gas component was included and excluded in the model. The flow regimes that can be observed in both plots are similar to those for 4 fracture stages. However, the linear and fracture interference flow periods are significantly shorter, and boundary effects appear to be present. Comparison of the Figures 4.11 and 4.12, indicates that the duration of the both the linear flow and the fracture interference periods are longer while the boundary effects are barely present, when the adsorbed gas component is included in the model.

Figure 4.11: Diagnostic plot of inverse of flow rate (and its derivative) vs. time for 7 fracture stages (without adsorbed gas component).

Figure 4.12: Diagnostic plot of the inverse of flow rate vs. time (and its derivative) for 7 fracture stages (with adsorbed gas component).

Figure 4.13 and 4.14 illustrate the diagnostic plots for a horizontal well with 13 fracture stages with and without considering the adsorption component. The flow regimes that can be observed in both plots are similar to those for 4 fracture stages. However, the linear and fracture inference flow periods are significantly shorter, and boundary effects appear to be present. Comparison of the Figures 4.13 and 4.14, indicates that the duration of the both the linear flow and the fracture interference periods are longer while the boundary effects are barely present when the adsorbed gas component is included in the model. Moreover, as illustrated in Figure 4.13, when adsorbed gas component is included, two linear flow regimes can be observed. The first linear flow (formation linear flow) is from inside the reservoir (between the fractures), and the second one is a linear flow from the exterior of the reservoir (compound flow).

Figure 4.13: Diagnostic plot of inverse of flow rate vs. time (and its derivative) for 13 fracture stages (without adsorbed gas component).

Figure 4.11: Diagnostic plot of inverse of flow rate vs. time (and its derivative) for 13 fracture stages (with adsorbed gas component).

4.3 *Objective 3: Impact of desorption on the production decline behavior*

In order to understand the production decline behavior of shale gas reservoir and to demonstrate the impact of gas desorption on the production decline behavior. First, conventional decline model was used to estimate the decline based on the early production data. Then, a correlation was developed using Arps model to study the effect of gas desorption on the decline constants.

Table 4.7 illustrates the results of decline curve constant that were estimated for each period. As previously mentioned, since in shale gas reservoirs, transient flow periods is long, it is important to avoid using the conventional decline curve method (Arps decline curve) to estimate the long term production decline based on the early production data. Moreover, entire production profile cannot be characterized by using a single b value. Conventional decline curve method for shale gas reservoirs could lead to significant over estimation of reserve. Moreover, Table below shows that in the early time, linear flow

regime ($b=2$) can be seen. Also, in later production time, harmonic decline ($b=1$) can be observed (Belyadi, F. et al., 2012).

Table 4.7: Values of b and D_i for different number of fracture stages (Belyadi, F. et al., 2012).

Number of Fracture Stages	Period, Years	b	D_i	Period, Years	b	D_i
4	2 to 7	2	2.4	14 to 30	1	0.64
7	0.5 to 2	2	11	6 to 24	1	0.78
13	0.2 to 0.5	2	53	2 to 20	1	1.6

Figure 2-B (Appendix B) shows the 30 years simulated production profile which was closely fitted to Arps decline curve model. This shows that 30-year production data that was used contain both transient and BDF production data. Moreover, Arps decline model can be best fitted to 250 ft of spacing production profile. That is due to the fact that, the Boundary dominated flow (BDF) can be seen much earlier compared to 500 ft of spacing (Mashayekhi, A. et al, 2014).

Figure 4.15, 4.16, and 4.17 demonstrate the results for the ratio of each constant for different numbers of the years for with and without adsorbed component. As can be seen, the adsorbed gas influences the decline curve constant ratios only when the hydraulic fracture spacing is wide (500 ft.). That is because gas desorption is minimal during the early production period. As a result, a constant ratio is less impacted by desorption characteristics for wider hydraulic fracture spacing.

Figure 4.15: constant ratio (n/n_{30}) vs. number of the years for with and without adsorbed gas (Mashayekhi, A. et al, 2014).

Figure 4.16: constant ratio (d/d_{30}) vs number of the years for with and without adsorbed gas component (Mashayekhi, A. et al, 2014).

Figure 4.17: constant ratio (q/q_{30}) vs number of the years for with and without adsorbed gas (Mashayekhi, A. et al, 2014).

5. Conclusions:

The main purpose of this study was to evaluate the impact of the gas desorption on the production behavior of ultra-low permeability formation such as Marcellus shale. As the results, the following conclusions were attained:

1. Langmuir concentration has significant impact on the initial gas in place.
2. Langmuir concentration has only a minor impact on the adsorbed gas recovery due to ultra-low formation permeability.
3. Diffusion coefficient has only a minor impact on the adsorbed gas recovery factor due to ultra-low formation permeability.
4. The additional recovery contributed by the gas desorption is 18% for a horizontal well with 13 hydraulic fracture stages. Therefore, the adsorbed gas component should be considered for reliable recovery estimation.
5. The adsorbed gas recovery increases with the fissure permeability.
6. The adsorbed gas recovery increases with the number of hydraulic fracture.
7. Gas desorption does not change the type of flow regimes but alters the duration of the various flow period and may mask some periods completely.
8. The adsorbed gas influences the decline curve constant ratios only when the hydraulic fracture spacing is wide (500 ft.). That is because gas desorption is minimal during the early production period.

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Appendix A

Figure A-1 shows the core analysis results for average porosity and permeability ranges for Devonian shale core analysis (Soeder, D.J., 1988).

Sample	Formation	Depth (ft)	Net Stress (psi)	Porosity to Gas (%)	Permeability μ d
EGSP-WV-5	Huron shale	3,028	1,750	< 0.10	0.066
Mason County			3,000	< 0.10	0.014
Moore #1 (KY)	Huron shale	2,904	1,750	0.12	0.022
Leslie County			3,000	< 0.10	0.005
EGSP OH-6/4	Huron shale	2,771	1,750	< 0.10	6.80
Gallia County			3,000	< 0.10	4.50
EGSP OH-9	Huron shale	3,245	1,750	0.15	0.001
Meigs County			3,000	< 0.10	< 0.0002
EGSP WV-6	Marcellus	7,448.5	3,000	9.28	19.613
Monongalia County			6,000	8.67	5.909
EGSP OH-6/4*	Huron shale	2,770.8	1,750	< 0.10	8.342
Gallia County			3,000	< 0.10	5.489
EGSP OH-6/5	Huron shale	2,441.4	1,750	0.18	0.248
Gallia County			3,000	< 0.10	0.008
EGSP OH-8	Huron shale	3,325	1,750	< 0.10	0.194
Noble County			3,000	< 0.10	0.078

* Two plugs from the Well OH-6/4 core were run. A second plug was deemed necessary after first plug emerged from coreholder with a large, longitudinal crack.

Figure A-1: Average porosity and permeability ranges for Devonian shale core analysis

The below graphs shows the impact of matrix porosity on the adsorbed gas recovery factor. Figure 2-A shows that as matrix porosity increases, there is no impact on the adsorbed gas recovery factor. Also, as it can be seen in the Table 1-A, as the matrix porosity increases from 0.02 to 0.07, the cumulative adsorbed gas production decreases from 1.1 BCF to 0.68 BCF. Moreover, initial adsorbed gas in place decreases from 3.1 to 3 BCF. Therefore, lower recovery of adsorbed gas is attained as illustrated in Figure 2-A and Table 1-A.

Figure 2-A: impact of matrix porosity on the recovery of adsorbed gas

Table 1-A. shows the results for cumulative adsorbed gas production and adsorbed gas in place.

Matrix porosity	Cumulative Gas Production	Cumulative Free Gas Production	Cumulative Adsorbed Gas produced	Adsorbed Gas in Place
Fraction	Gp, BCF	BCF	BCF	BCF
0.02	3.159	2.12	1.04	3.15
0.05	5.023	4.23	0.79	3.12
0.07	6.12	5.43	0.68	3.05

Table 2-A shows the result for adsorbed gas recovery for matrix porosity ranges from 0.02 to 0.07

Matrix Porosity	Adsorbed Gas Recovery Factor
Fraction	Fraction
0.02	0.33
0.05	0.25
0.07	0.22

Figure 3-A shows that as matrix permeability increases, no impact on the adsorbed gas recovery. Also, as it can be seen in the Table 3-A as the matrix permeability increases from 0.0002 to 0.0008 md, the cumulative adsorbed gas production increases from 0.7 BCF to 0.8 BCF. Moreover, initial adsorbed gas stays the same. Therefore, slight increase in the adsorbed gas recovery factor can be seen as illustrated in Figure 3-A and Table 3-A.

Figure 3-A: impact of matrix permeability on the recovery of adsorbed gas

Table 3-A. The results for cumulative free gas and adsorbed gas production.

Matrix Permeability	Cumulative Gas Production	Cumulative Free Gas Production	Cumulative Adsorbed gas produced
md	Gp, BCF	BCF	BCF
0.0002	4.89	4.15	0.74
0.0004	4.98	4.22	0.76
0.0008	5.11	4.30	0.80

Figure 4-A shows that as fissure porosity increases there is slight impact on the adsorbed gas recovery factor

Figure 4-A: Impact of fissure porosity on the adsorbed gas recovery factor.

Table 4-A shows the results for recovery of adsorbed gas

Fissure Porosity	Adsorbed Gas Recovery Factor
Fraction	%
0.002	25.05
0.005	24.55
0.007	24.20

Figure 4.8 shows the impact of the number of hydraulic fracture stages on the on the cumulative free gas and total gas production.

Figure 4-A: Impact of number of fractures on free gas and total gas production.

Appendix B

Figure 1-B the result of production history matching for a Marcellus Shale well in WV (Belyadi, F. et al., 2012)

Figure 2-B: 30 years simulated production profile was fitted to Arps decline curve model.

Appendix C

In this model we assumed that some of the natural fractures are not connected to the hydraulic fractures at the tip of hydraulic fracture. Fissure permeability was varied from 0.004 to 0.001 md.

Figure 1-C: fissure permeability were varied from 0.0004 to 0.001 md.

Figure 2-C: compares the base model and the model with varied fissure permeability.

Figure 2-C shows that cumulative gas production is about the same when we are comparing production profile for the base model (fissure permeability=0.004 md) and alternative model with fissure permeability ranges from 0.004 to 0.001 md.