Development of water production type curves for horizontal wells in coalbed methane reservoirs

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DEVELOPMENT OF WATER PRODUCTION TYPE CURVES FOR HORIZONTAL WELLS IN COALBED METHANE RESERVOIRS

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Thesis submitted to the College of Engineering and Mineral Resources at West Virginia University in partial fulfillment of the requirements for the degree of

Master of Science
In
Petroleum and Natural Gas Engineering

Approved by
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Dr. Ilkin Bilgesu

Petroleum and Natural Gas Engineering

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Coalbed methane is an unconventional gas resource that consists of methane production from the coal seams. The key parameters for the evaluation of coalbed methane (CBM) prospects are the gas resources, reserves and deliverability. Coalbed methane reservoirs are dual-porosity media where the vast majority of the gas is stored in the low permeability coal matrix (primary porosity) by sorption. The flow to production wells, however, occurs through the coal’s natural fracture system (secondary porosity), which stores relatively small amounts of gas, because coal matrix practically has no permeability.

For the gas to be released from the coal, its partial pressure must be reduced, and this is done by removing water from the coalbed fractures. During the dewatering process, the gas desorbs from the coal matrix, thereby gas rate increases and the water saturation decreases. The water production declines rapidly until the gas rate attains a peak value and water saturation approaches the irreducible water saturation i.e., reaches connate water saturation. Once the peak gas rate is attained, CBM reservoirs act like a conventional reservoir. Reservoir engineers usually use production decline curves in order to predict well performance.

Since the behavior of CBM reservoirs are complex when compared to conventional reservoir, the use of a numeric simulator is the best way to predict the CBM production behavior. Operating a simulator requires in-depth knowledge and detailed data to get accurate results. They are also expensive to small producers. Considering these factors, using a simulator might not be the best
option. Hence, in order to develop a simple and yet a reliable tool to forecast the production in a CBM reservoir with good accuracy, it was taken upon to develop type curves for both gas and water production.

The objective of this study was to develop a simple and reliable tool was developed to help with water production predictions in horizontal coalbed methane wells that are located in the (Northern Appalachian Basin). Upon development of a unique set of type curves, independent producers will be able to evaluate the future production of water from the wells. A correlation for the peak water rate was also developed in order to forecast production if no production data is available.
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I would like to thank Professor Dr. Ilkin Bilgesu for his participation in my committee.

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Thanks to my friends Amol Bhavsar, and Allen Nfeonsam for helping me and being special coworkers.

I dedicate my work to my Parents, My Brother and Sisters, who represent the best inspiration in my life. Mom and Dad, your unique ways of encouragement always filled my heart with joy and enthusiasm to progress ahead in life and I feel fortunate to be the special one. Thanks for all your noble upbringing and self-sacrificing love, guidance, support and encouragement that helped me with years to survive this harsh phase of life.

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NOMENCLATURE

\( A \) = Area.
\( C_t \) = Compressibility Factor, \( 1/\text{psia} \).
\( h \) = Thickness, ft.
\( k \) or \( k_x \) = Permeability, md.
\( K_y \) = Permeability in \( y \)-direction, md.
\( K_z \) = Permeability in \( z \)-direction, md.
\( L_w \) = Horizontal Well Length, ft.
\( P_i \) = Pressure at initial conditions (Fracture Pressure), psia.
\( P_{wf} \) = Flowing bottomhole pressure, psia.
\( P_L \) = Langmuir pressure constant, psia.
\( P_{(\text{Initial})} \) = Initial Reservoir Pressure, psia.
\( P_{(\text{Desorption})} \) = Critical Desorption Pressure, psia.
\( q_{\text{peak}} \) = Peak water rate, Bbl/day.
\( q \) = Water rate, SCF/D.
\( q_{(\text{peak})_{WD}} \) = Dimensionless water peak rate.
\( r_w \) = radius of wellbore, ft.
\( t \) = Time, days.
\( t_D \) = Dimensionless time.
\( V_L \) = Dry-ash-free Langmuir volume constant, SCF/ton.
\( W_i \) = initial Water in place, SCF.
\( z \) = Compressibility factor.

Symbols Used

\( \rho \) = Density, g/cm\(^3\).
\( \mu_i \) = Viscosity, cp.
\( \phi \) = Fracture porosity, \%.
Chapter I
Introduction

Ever since coal mining started, coalbed methane posed a problem to miners. At the start coalbed methane was disposed by venting or flaring. Although coal miners were aware that methane from coal beds could be a potential fuel, due to many factors they were not successful in capturing and marketing the gas from coalbed methane reservoirs. First being that coal mines in those days were shallow when compared to today’s coal mines, and generally, the amount of gas differs with depth. As the mines were shallow, there was less coalbed methane to be captured in the mining process. Second, most of the gas is held by the process of adsorption. It is released from coal at very low pressure, and the technology needed to extract this methane at low pressure, and pressurize it, at the same time keeping the mines safe, was not available. Third, there was too much methane available from traditional oil and gas operations, so there was no strong interest in developing the technology needed for commercial production of coalbed methane$^1$.

CBM wells produced more water initially when compared to conventional reservoirs. Methane gas is adsorbed to the surface of the coal because of the water-contributed pressure in the coal bed reservoir. Removal of this water by pumping is necessary for same reasons; it helps lower the pressure in the reservoir and it stimulates desorption of methane from the coal. The water in coal beds contributes to pressure in the reservoir that facilitates methane gas adsorbed to the surface of the coal. The water coproduced with methane is not reinjected into the producing formation to enhance recovery, but is disposed of or treated to remove dissolved sediments before used for beneficial purposes$^2$.

Disposal of this large amount of water is complicated as much of the water is of low quality. The main problem with the disposal of well is their cost, ranging from
$400,000 to $1,200,000 depending on depth and stimulation type. The total disposal cost for water to bring to the surface will be approximately $1.0 to $4.0 per barrel. The high capital cost is a restriction for small independent operators. Some of the factors attributed to the disposal costs included pipeline maintenance and repair costs, electrical costs to operate pumps, virtually round-the-clock staffing to operate electrical generators, life of the facility, depth of the injection well, chemical treatments to disinfect water that is reused for livestock.\(^3\)

Water from CBM wells contain high concentration of dissolved sediments and a high sodium absorption ratio. This water cannot be used for domestic or animal consumption, and its high saline and sodium content makes it unsuitable for agriculture irrigation.\(^3\)

Looking at facts and complications associated with water produced from CBM, it is important to predict the amount of water that will be produced in the CBM wells, especially in the early stages of the production. Hence, it was taken upon to develop type curves for water production in a horizontal well to predict the behavior of the well to produce water along with the amount of water produced with time.

<table>
<thead>
<tr>
<th>Basin</th>
<th>State</th>
<th>Produced Water</th>
<th>Water Production (Bbl/d/well)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Powder River</td>
<td>Wyo., Mont.</td>
<td>500</td>
<td>400</td>
</tr>
<tr>
<td>Raton</td>
<td>Colo., NM</td>
<td>1500</td>
<td>226</td>
</tr>
<tr>
<td>San Juan</td>
<td>Colo., NM</td>
<td>8000</td>
<td>25</td>
</tr>
<tr>
<td>Unita</td>
<td>Utah</td>
<td>15000</td>
<td>215</td>
</tr>
</tbody>
</table>
Chapter II
Literature Review

2.1 Origin and Discovery of Coalbed Methane.

Methane gas is generated during the formation of coal through ‘coalification’ process of vegetal matter. This can broadly be divided into biochemical and physico-chemical stages of coalification incorporating five successive steps.

Peatification - Anaerobic degradation of organic materials in the peat swamp.

Humification - Formation of dark colored humic substances by anaerobic degradation.

Bituminization - Generation of hydrocarbons with increase in temperature and pressure.

Debituminization - Thermal degradation of matter and generated hydrocarbons.

Graphitization - Formation of graphite.

Many physical and chemical changes, governed by biological and geological factors, occur during these processes. Whereas darkening in color and increase in hardness and compactness are the main physical changes, loss in moisture and volatile contents, and increase in carbon content are the main chemical changes. Many acids (humic, fatty, tannin, gallic, etc.) and dry and wet gases (\(\text{CH}_4\), \(\text{CO}_2\), \(\text{N}_2\), \(\text{N}_2\text{O}\), \(\text{H}_2\text{S}\), ethane, propane, butane, etc.) are formed during decomposition of the organic matter. All the changes brought about are attributable to the release of –COOH (carboxyl), >C=O (carbonyl), –OH (hydroxyl) and –OCH\(_3\) (methoxyl) functional groups from the organic compounds which cause the decomposition of vegetal source matter.

Biochemical stage of coalification, beginning with the accumulation of vegetal matter and terminating at the sub-bituminous stage of coal formation, leads to the formation of a wide range of degradational products.
The organo-petrographic entities of coal (termed ‘macerals’) by the partial oxidation and hydrolytic decomposition of dead vegetal matter accumulated in water-saturated wet lands (basins) by micro-organisms (fungi, aerobic bacteria, insects, etc.). Further decomposition by anaerobic bacteria extracts oxygen from organic molecules of vegetal matter and results in high concentration of hydrogen. Part of this hydrogen is released as methane or ‘marsh’ gas and the rest is absorbed by humic colloids\(^5\).

During subsequent geochemical stage of coalification, rising temperatures and pressures, due to subsidence of the basin, either by growing thickness of overburden or by tectonic activities, generate hydrocarbons (hydrogen-rich constituents). Thermal cracking of the free lipid hydrocarbon fraction and/or cracking of the kerogen fraction of coal generates methane gas. Thus, the generation of coal bed methane during coal formation occurs in two ways:

(i) By metabolic activities of biological agencies (biological process), and
(ii) By thermal cracking of hydrogen-rich substances (thermogenic process)\(^5\).

![Figure 2.1: Coalification Process\(^5\)]
The course of biochemical decay and metamorphic transformation of vegetable matter generates large quantities of gases, as much as 1,300 cubic meters per tonne of coal formed. The amount of gas produced differs with the rank of coal. The ability of the coal to retain the gas, i.e., its adsorptive capability, also depends on the rank of coal being formed (CIAB, 1993).

As temperature and pressure increases during the coalification process, the rank of the coal also changes thus allowing it to adsorb different volumes of methane (CIAB, 1993).

Figure 2.2 shows the Desorption Isotherms as a Function of Coal Rank:

![Desorption Isotherms as a Function of Coal Rank](image)

Figure 2.2: Desorption Isotherms as a function of Coal Rank

Coalification process yields large amounts of gas, as much as 1,300 cubic meters per ton of coal formed, in which a large amount escapes during burial and
metamorphosis of the decaying material. The gas retained will range from negligible to as much as 25 cubic meters per tonne (CIAB, 1993)\(^6\).

Gas production from coal represents a recent technology in petroleum industry. Not so long ago, did a methane gas that is associated with coal mining represent only great threat and main danger to mineworkers. Twenty years ago, people started to realize that producing gas from the coals before mining not only help and drastically decrease the danger of blowout in the mines, but can also be used as a fuel. In 1982, the gas production from the coals in the United States was zero (CIAB, 1993)\(^6\).

The gas produced from coal beds is almost completely methane, usually containing small amounts of other hydrocarbons, hydrogen, carbon dioxide, carbon monoxide, and nitrogen. However, with the increase in demand for energy, there is a tremendous technical development for producing unconventional sources of natural gas. More specifically, advancements in reservoir characterization, simulation, and production have been the keys for economic development of the CBM. It is expected that until 2010, demand for unconventional natural gas will reach 12.78 trillion cubic feet, rising at an Average Annual Growth Rate (AAGR) of 10.7% from 7.68 trillion cubic feet (CIAB, 1993)\(^6\).

### 2.2 Global Coal Distribution

Worldwide CBM resources are estimated to range between 5,800 and 24,215 Tcf. Production and usage of CBM in the United States has increased in the last 15 years. CBM accounts for 9% of the total US gas production. North America’s resources range between 951 to 4,383 Tcf\(^7\).

The major coal resources exist in 69 countries. Around 5800 millions short tons of coal is consumed by world annually, out of which 75% is used for electricity
generation. The regions including India and China use 1800 million short tons. This figure is predicted to increase to 3000 million short tons by the year 2025. USA consumes about 1100 short tons of coal every year, using 90% of it for electricity. Coal is the fastest growing energy source in the world, with coal use increasing by 25% for the three-year period ending in December 2004.

Thirty-five major coal countries have some CBM activity. Figure 2.3 shows the major sectors of coal distribution over the globe. The largest potential resources, which also have the largest degree of uncertainty, are in the former Soviet Union with 4,000 to 16,116 Tcf, whereas South America and Europe range from 15 to 32 Tcf and 161 and 269 Tcf, respectively. Africa ranges between 27 and 55 Tcf; the Middle East has no CBM resources. CBM resources of the Asia Pacific region, which includes China, ranges from 646 to 3,360 Tcf.

Figure 2.3: Global Coal Distribution (Reprinted from Mawor et al., 1996)

2.3 Coalbed Methane in US

There were 6,494 CBM wells drilled during 2005, up 12% from 2004’s figure. The number of CBM wells under production in 2004, has been revised upward by 436 wells as new, more complete data have trickled in from several states. This year,
a nearly 18% jump in CBM drilling is forecast for 7,652 wells, with more than 3,600 wells already spudded in the first half. Furthermore, permitting will remain at a high level, with 12,264 permits expected this year for a 1% increase. The leading state for CBM drilling remains Wyoming, followed by Kansas and Colorado. About 60% of all US CBM wells are drilled to a depth of 1,100 ft or less. Typical half-life of a well is 13 years. (The US Energy Information Administration - EIA)\(^8\).

CBM production took a 7.5% jump to 1.72 Tcf in 2004, after declining slightly in 2003. Although EIA has yet to report a 2005 figure, World Oil is estimating last year’s output at about 1.78 Tcf, or a 3.5% increase (The US Energy Information Administration - EIA)\(^8\).

The leading US CBM producing region is the San Juan basin of Colorado and New Mexico. Together, these states contribute about 60% of all US CBM output, which EIA said was 2.87 Bcfgd in 2004, and which likely climbed above 2.9 Bcfgd in 2005. EIA’s 2004 proved reserve figure for the two states was 10.95 Tcf (The US Energy Information Administration - EIA)\(^8\).

The next largest CBM production area is the Powder River basin, where Wyoming and Montana produced CBM of a combined rate of just over 900 MMcfd in 2004, a figure that increased to nearly 1.0 Bcfgd in 2005. EIA’s 2004 proved reserve figure for these two states, together, was roughly 2.4 Tcf. There is an estimate that more than 32,000 CBM wells are now producing in the Powder River basin (The US Energy Information Administration - EIA)\(^8\).

As per EIA 2005 annual report, present coalbed resources are 83 Tcf, from which 63 Tcf is located in Rocky Mountains, and 5 Tcf in Gulf Coast/ E&C Texas, and 6 Tcf in Mid-continent, and 1 Tcf in southwest and about 8 Tcf in other parts of US(EIA, Annual Report)\(^8\).

Coalbed methane currently accounts for 10% of the total natural gas being produced in the United States. However, the Rocky Mountain States of New
Mexico, Utah, Colorado, Wyoming, and Montana are estimated to hold more than 1.5 trillion cubic meters of undiscovered natural gas being placed and drilled. It is anticipated that there will be more than 400,000 operating CBM wells in the five-state area by 2010\textsuperscript{9}.

The major coalbed methane resources in the United States are located in 12 basins: San Juan (10 Tcf), Black Warrior (4.4 Tcf), Powder River (24 Tcf), Uinta & Piceance (5.5 Tcf), Central and Northern Appalachian (10.6 Tcf), Raton-Mesa (3.7 Tcf), Hanna-carbon (4.4 Tcf), and SW coal Region\textsuperscript{9}.

The two most productive basins are Black Warrior in Alabama and San Juan in northern New Mexico with the total estimated CBM gas reserves of 20 Tcf and 88 Tcf respectively\textsuperscript{9}.

Development and production of CBM began in the Appalachian basin nearly 60 years ago. Coal mines in the Appalachian basin emit approximately 180 million cubic feet (MMcfd) of high-quality methane into the atmosphere daily\textsuperscript{9}.

\textbf{Figure 2.4: Coalbed Methane Basins in United States (DOE, 2005)}\textsuperscript{9}
The existence of mines in West Virginia, Southwest Virginia, Eastern Kentucky, Ohio, Pennsylvania, Tennessee, and Alabama with high gas emissions of methane resulted in further investigation into the economic development of this unconventional energy source is warranted. Appalachian coals occur as multiple beds, individually up to 14 feet thick (Pittsburgh coalbed in Pennsylvania and West Virginia). The gas content of these bituminous coal seams has been measured at 93 cubic feet per ton (cu ft/t) from a depth of 149 feet (Waynesburg Coalbed, Pennsylvania) to over 560 cu ft/t have been measured where the overburden is 685 feet thick (Peach Mountain Coalbed).
2.4 Transport Mechanism in CBM Reservoir

The characteristics of CBM reservoirs vary from conventional gas reservoirs in several areas (Table.2.1). Coal is a heterogeneous and anisotropic porous media which is characterized by two distinct porosity (dual-porosity) systems: macropores and micropores. The macropores, also known as cleats, constitute the natural fractures common to all coal seams. Micropores, or the matrix, contain the vast majority of the gas. This unique coal characteristic has resulted in classification of CBM as an “Unconventional” gas resource.¹⁰

<table>
<thead>
<tr>
<th>Characteristics</th>
<th>Conventional</th>
<th>CBM</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas Generation</td>
<td>Gas is generated in the source rock and migrates into reservoir</td>
<td>Gas is generated and trapped within the coal.</td>
</tr>
<tr>
<td>Structure</td>
<td>Randomly-spaced Fractures</td>
<td>Uniformly-spaced Cleats</td>
</tr>
<tr>
<td>Gas Storage Mechanism</td>
<td>Compression</td>
<td>Adsorption</td>
</tr>
<tr>
<td>Transport Mechanism</td>
<td>Pressure Gradient (Darcy’s Law)</td>
<td>Concentration Gradient (Fick’s Law) and Pressure Gradient (Darcy’s Law)</td>
</tr>
<tr>
<td>Production Performance</td>
<td>Gas rate starts high then decline. Little or no water initially. GWR decreases with time</td>
<td>Gas rate increases with time then declines. Initially the production is mainly water. GWR increases with time</td>
</tr>
<tr>
<td>Mechanical Properties</td>
<td>Young Modules~$10^6$, Pore Compressibility~$10^{-6}$</td>
<td>Young Modules~$10^7$, Pore Compressibility~$10^{-4}$</td>
</tr>
</tbody>
</table>

Gas in the coal can be present as free gas within the macropores or as an adsorbed layer on the internal surfaces of the coal micropore. The micropore of coal has immense capacity for methane storage. Typically, coal can store far more gas in the adsorbed state than conventional reservoirs can hold by compression at pressures below 1000 psia. The porosity of the cleat system is small, and if any free gas is present, it would account for an insignificant portion.
of the gas stored in the coal. Most of the gas in coals is stored by adsorption in the coal matrix (Remner D.J., et al., 1986).  

![Image of coal structure and gas flow](image)

**Figure 2.7: Transportation of Methane in CBM Reservoir**

### 2.5 Production Behavior in CBM Reservoirs

Gas production from coalbed methane reservoirs may follow three stages as the reservoir pressure declines from reduction of hydrostatic pressure by pumping off the water in the reservoir (Figure 2.8). Most coalbed methane reservoir are found to be under near hydrostatic pressure and are saturated with water. Methane is held within the porous coal matrix by an adsorption mechanism that is controlled by the reservoir pressure. When a water-saturated coalbed methane well is first produced, it is common to encounter only single-phase or saturated flow i.e., only water is produced. This is Stage 1 where only one phase exists and pore spaces are fully saturated with water.

As water is removed and reservoir pressure is reduced further; methane-gas bubbles begin to form as a result of desorption from the coal, and pore spaces are partially saturated with water. The bubbles block some of the pathways that were originally available to water flow; thus the relative permeability of the formation to water reduces. The gas does not yet flow, however (except as
trapped gas bubbles in water), because the bubbles are not connected within the porous coal matrix nor in the cleat or natural fracture system of the coalbed. Stage 2 is called an unsaturated, single-phase flow regime where, although two phases are present (water and gas), only the water phase is mobile. Because of reduced permeability to water, the pressure drop in this regime increases faster than in a fully water-saturated flow regime. Stage 3 is reached as the reservoir pressure decreases and additional gas is desorbed. The gas saturation builds until the gas bubbles connect and form a continuous pathway to the wellbore. As shown in Figure 2.8 two-phase flow begins at the point where the relative permeability to gas becomes nonzero. As the reservoir pressure is further reduced and water saturation declines, the relative permeability to gas increases at the expense of the relative permeability to water. This sequence of regimes progresses outward from the wellbore into the formation over time, i.e., when two-phase flow occurs at the wellbore.

Figure 2.8: Typical Coalbed Methane Production Profiles for Gas and Water Rates: Three Phases of Producing Life.
unsaturated and saturated single-phase flows occur simultaneously farther into the formation\textsuperscript{13}.

### 2.6 Necessity to Develop Type Curves

For the gas to be released from the coal, its partial pressure must be reduced, and this is done by removing water from the coalbed fractures. During the dewatering process, the gas desorbs from the coal, thereby gas rate increases and the water saturation decreases. The water production declines rapidly until the gas rate attains a peak value and water saturation approaches the irreducible water saturation i.e., reaches connate water saturation. The dewatering process usually lasts between 6 and 18 months. Once the peak gas rate is attained, CBM reservoirs act like a conventional reservoir. Reservoir engineers usually use production decline curves in order to predict well performance.

Since the behavior of CBM reservoirs are complex when compared to conventional reservoir, the use of a numeric simulator is the best way to predict the CBM production behavior\textsuperscript{8}. Operating a simulator requires in-depth knowledge and detailed data to get accurate results. They are also expensive to small producers. Considering these factors, running a simulator might not be the best option. Hence, in order to develop a simple and yet a reliable tool to forecast the production in a CBM reservoir with good accuracy, it was taken upon to develop type curves for both gas and water production.

### 2.7 Horizontal Wells in Coalbed Methane

Horizontal wells in coalbed methane is a comparatively new concept and many of the drilling projects that have been proposed using this technology are still in their infancy. Significant potential natural gas resources remain in low permeability reservoirs of the Appalachian basin.

The main advantage of horizontal well technology compared to vertical is that, the direction of the borehole can be controlled with respect to the principal permeability directions of the coal seam. Therefore, in coalbed methane
reservoirs, a more effective production technique may be a horizontal borehole placed perpendicular to the maximum permeability direction. This would result in enhanced access to the reservoir through the natural fracture network and improve the rate of water production, accelerating the gas desorption process. The production profile for horizontal CBM wells varies from that of a vertical CBM well. Since the horizontal well is drilled perpendicular to the maximum permeability direction, there is more accessibility for the water to flow into the wellbore, thus allowing the dewatering process to be accelerated. When compared with Figure 2.9 one can notice that dewatering stage, occurs faster in horizontal wells. In deciding between drilling a horizontal wells over vertical well, three properties are taken in account; (1) coal thickness; (2) natural fractures; (3) anisotropic permeability (Osisanya S. O. and Schaffitzel R. F., 1996)\textsuperscript{15}

![Figure 2.9 Water production in Vertical and Horizontal Wells](image)
2.8 Langmuir Isotherms

The basis for CBM reservoir engineering is the Langmuir Isotherm equation, which can be written as shown in equation 1. The Langmuir Volume ($V_L$) or maximum adsorbed volume is the maximum volume (normally measured under standard temperature and pressure) adsorbed per unit volume of the reservoir at infinite pressure, and the Langmuir Pressure ($P_L$) is the pressure at which the total volume adsorbed is equal to one half of the Langmuir Volume ($V_L$). Langmuir volume and pressure values employed in this study are tabulated in Appendix-A.

$$V = V_L \times \frac{P}{P_L - P} \quad (1)$$

Where:

$V$ = Volume, SCF/ton

$P$ = Pressure, psia

$V_L$ = Langmuir volume, scf/ton

$P_L$ = Langmuir pressure, 1/psi

2.9 Coalbed Methane Production Type Curves

The use of conventional decline curve analysis cannot be utilized because there is a complex interaction of coal matrix and cleat system properties that are coupled through desorption process. (Aminian K, et.al, 2004).

CBM reservoirs behavior were studied in depth and a set of type curves were developed as an efficient and economical tool to analyze and forecast the performance of CBM reservoirs by Garcia in 2004 as a part of her MS thesis (Figure 2.10). During the study the Northern Appalachian Basin CBM reservoir characteristics were used as input to a reservoir simulator to predict the production behavior. A two-dimensional, two-phase cartesian CBM model was built. The cartesian model grid size was 13 x 13 blocks, each block with a length of 100 ft for a total of 40 acres of spacing area. The reservoir simulation software used was GEM, developed by Computer Modeling group (CMG). The software
features a range of dual porosity and dual permeability techniques for modeling fractured formations. It also includes options for gas sorption in the matrix, gas diffusion through the matrix, and two phase flow through the fracture system.

![Graph of CBM Gas Production Type Curve](image)

**Figure 2.10: CBM Gas Production Type Curve (Adopted from Garcia, 2004).**

Garcia evaluated the dimensionless groups by varying eight different parameters. Garcia concluded that fracture pressure, sorption time, cleat porosity, and critical desorption pressure do not have any significant impact on CBM type curves whereas, flowing bottom-hole pressure appeared to be one of the properties with highest impact on CBM type curves particularly in the latter parts of production history. A set of type curves for several flowing bottom-hole pressure were developed.

\[
q_{D} = \frac{q}{q_{\text{peak}}} \\
\frac{t_{D}}{G_{i}} = \frac{t \times q_{\text{peak}}}{G_{i}}
\]  

(2)
The impact of stimulation was considered in a previous study by Sanchez \(^{18}\) and he concluded that skin factor does not influence the shape of the CBM gas type curve, however when the well is stimulated the skin factor alters the gas peak value that is used in development of dimensionless groups.

Arrey\(^{19}\) in 2004, evaluated the impact of Langmuir isotherm constants, Langmuir Pressure \((P_L)\) and Langmuir Volume \((V_L)\) on the gas production type curves. Arrey concluded that changes in \(V_L\) values do not significantly impact the shape of the gas production type curves however; changes in \(P_L\) values have a significant impact on the gas production type curves. Figure 2.11 shows the effect of \(P_L\) changes on the CBM gas production type curves.

Bhavsar\(^{20}\) in 2005 evaluated the impact of reservoir properties on the gas production type curves for Northern Appalachian. He also developed correlation for peak gas rate, correlation for initial (maximum) water rate, and dimensionless groups for water production type curves. Bhavsar developed a set of CBM water production type curve. He concluded that flowing pressure, critical desorption pressure and skin factor influenced the type curves.
Figure 2.11: Effect of Bottom-hole Pressure on the CBM Gas Production Type Curve (Adopted from Arrey, 2004.)

\[ q_D = \frac{q}{q_{peak}} \]

\[ t_D = \frac{tq_{peak}}{C_i} \]

Figure 2.12: Effect of $P_L$ Changes on the CBM Gas Production Type Curves (Adopted from Arrey, 2004.)
Figure 2.13: Impact of $V_L$ on Water Type Curves at Constant $P_L$
(Adopted from Bhavsar, 2005)

Figure 2.14: Impact of $P_L$ on Water type Curves at Constant $V_L$ (Adopted from Bhavsar, 2005)
Figure 2.15: Type Curves for Skin Factor Change (Cartesian) (Adopted from Bhavsar, 2005)

$$t_{WD} \equiv \frac{t \times \frac{q_{iw}}{W_i}}{W}$$

Figure 2.16: Type Curves for Skin Factor Change (Log-log) (Adopted from Bhavsar, 2005)
Sunil Lakshminarayanan\textsuperscript{21} in 2006 evaluated the impact of the impact of relative permeability on type curves for coalbed methane reservoirs. He concluded the following points.

The values of relative permeability in coal bed methane reservoirs primarily depends upon 3 constants, which are $n'$, $m'$ and $k$. Using the relative permeability values from 4 different samples of coal, the range values for the three constants were obtained and the effect of these constants on the production type curves of gas and water were studied.

\begin{equation}
    k_{rg} \propto k (1/ S_w^*)^{m'}
\end{equation}

\begin{equation}
    k_{rw} \propto (S_w^*)^{n'}
\end{equation}

1. The value of constant $k$ does not affect the performance by any extent.
2. The value of $m'$ seemed to be more significant with the gas curves. As the value of $m'$ increased, the production of the reservoir slowed down. However, $m'$ did not have significant effect on water curves.
3. The value of $n'$ seemed to be more significant with the water curves. The variation in the water curves for the extreme ranges seemed very significant. Whereas, the variation in the gas curves was comparatively negligible.

Figure 2.18: Impact of $m'$ on the Shape of the Type Curve (Adopted from Lakshminarayanan, 2006)

Figure 2.19: Impact of $n'$ on the Shape of the Type Curve (Adopted from Lakshminarayanan, 2006)
Nfonsam\textsuperscript{22} in 2006 studied impact of reservoir properties on gas production type curves in horizontal wells for Northern Appalachian basin. The impact of nine (9) formation and operational parameters; permeability, porosity, thickness, critical desorption pressure, fracture pressure, flowing bottomhole pressure, and a ratio of horizontal length to area, Langmuir pressure and volume were studied to evaluate their impact on the type curve. He concluded that permeability and Langmuir pressure ($P_L$) significantly impact on the type curve.

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{Fig2.20.png}
\caption{Effect of Permeability on Shape of Type Curves for Horizontal Wells (Adopted from Nfonsam, 2006)}
\end{figure}
Figure 2.21: Effect of Langmuir Pressure on Shape of Type Curves for Horizontal Wells (Adopted from Nfonsam, 2006)

Figure 2.22: Average Type Curve for Permeability for Horizontal Wells (Adopted from Nfonsam, 2006)
The reservoir models developed using simulators, are excellent tools to study the impact of reservoir properties on production. CMG (Computer Modeling Group) is one such kind of software extensively used for research.

CMG works on six different applications such as (1) BUILDER, Pre-processing Applications, (2) IMEX, Black Oil Simulator, (3) STARS, Steam Thermal Advanced Processes, (4) GEM, Generalized Equation-of-State Model Compositional Reservoir Simulator, (5) WINPROP, Phase Behavior Analysis, and (6) RESULTS, Post-processing Applications. During this study, three applications of CMG were used for developing Reservoir model for coalbed methane, BUILDER, GEM, and RESULTS.
Figure 2.24: CMG’s Modeling Tools

BUILDER is module used to prepare reservoir simulation models. Again, BUILDER has two modules, for two different applications, which are: (1) Grid Builder and (2) Model Builder.

The **Grid Builder** is used to create simulation grids and rock property data for GEM and other applications. It allows the user to easily create, edit, and positioning grids with respect to geological maps, interpolating geological structure, and rock properties. The grid is displayed in 2D and 3D views to allow the user to check the grid performance.

The **Model Builder** is used to input data files for GEM and other applications. It displays Relative Permeability and PVT curves in graphic from which it can be adjusted directly. In addition, the Model Builder has an automatic error checking and data validation.

**GEM** is a second module of CMG that we used in this study. This tool modifies any type of reservoir with complex phase behavior and their interaction where the importance of the fluid composition and their interactions are essential to
understand the recovery process. GEM is a highly optimized simulator that has been proven in numerous field production situations around the world\textsuperscript{23}.

**RESULTS** is GEM’s set of post processing applications, designed for visualizing and reporting simulator output. With RESULTS, users can generate several informative graphs, and export simulation data onto excel sheets for further study. A RESULT is composed of two modules: (a) Results Graph and (b) Results Report\textsuperscript{23}.

**Results Graph**, produce high quality graphs of well production data from the simulator runs. Data can be displayed for individual wells or well layers, for group of wells or reservoir sectors. It is a great tool to understand the recovery process of the reservoir and to interpret the production of data of a specific well. **Results Report** produces tabular reports of any type of data generated during the reservoir simulation including well data and reservoir grid properties. It can also be used to compare data from different runs and generate economic analysis for discussion\textsuperscript{23}.

In this study, Model Builder and Grid Builder to build the 2D Cartesian model, GEM were used to run the simulated model. The outputs of the runs were analyzed in RESULTS and plots were developed in Results Graph\textsuperscript{23}. 
Chapter III
OBJECTIVE AND METHODOLOGY

The main purpose of this study was to develop a simple and reliable tool to forecast the performance of water for horizontal wells in CBM reservoirs. Also to develop a correlation for peak water production rate ($q_{peak}^{wd}$). In order to achieve the objective, methodologies consisting of the following steps were employed:

1. Develop a set of type curves for water production.
2. Develop a methodology to predict water production using type curves.
3. To verify the accuracy of the type curve and the correlation using a test run.

3.1 Development of Reservoir Model for the Northern Appalachian Basin

As a first step of thesis, literature survey was done on Appalachian basin to identify the range of all the parameters, which are to be studied. Once data was acquired, a two-dimensional cartesian base model was developed for a CBM reservoir.

The reservoir simulation software used in this study was GEM developed by the Computer Modeling Group (CMG). GEM is CMG’s advanced general equation of state, compositional, dual porosity reservoir simulator. Capable of modeling both coal and shale gas reservoirs. GEM includes options for gas sorption in the matrix, gas diffusion through the matrix, two-phase flow through the natural fracture system. Table 3.1 shows the input parameters used for the base case.

Permeabilities vary in i, j and k ($k_x$, $k_y$ and $k_z$) directions. Since coal is anisotropic, the horizontal well was drilled perpendicular to the direction with the highest permeability, that is, in i-direction (Figure 3.1). The permeability values for each
**Figure 3.1: Input Parameters used for base case**

<table>
<thead>
<tr>
<th>Input Parameters</th>
<th>Horizontal CBM Model</th>
</tr>
</thead>
<tbody>
<tr>
<td>Period of production</td>
<td>25 years</td>
</tr>
<tr>
<td>Porosity Model</td>
<td>Dual Porosity</td>
</tr>
<tr>
<td>Shape Factor Calculations</td>
<td>Gilman and Kazemi Style</td>
</tr>
<tr>
<td>Matrix-Fracture Transfer Calculations</td>
<td>Pseudo-capillary pressure</td>
</tr>
<tr>
<td></td>
<td>model with corrections</td>
</tr>
<tr>
<td>Grid</td>
<td>Cartesian</td>
</tr>
<tr>
<td>Reservoir Area</td>
<td>320 Ac</td>
</tr>
<tr>
<td>Grid’s Size</td>
<td>100ft x 100ft</td>
</tr>
<tr>
<td>Grid Properties</td>
<td></td>
</tr>
<tr>
<td>Grid top</td>
<td>1200 ft</td>
</tr>
<tr>
<td>Grid Thickness</td>
<td>10 ft</td>
</tr>
<tr>
<td>Porosity Matrix</td>
<td>0.5%</td>
</tr>
<tr>
<td>Porosity Fracture</td>
<td>2%</td>
</tr>
<tr>
<td>Permeability Matrix</td>
<td>0.01 md( i, j, k)</td>
</tr>
<tr>
<td>Permeability Fracture</td>
<td>10 md i, 3.3 md j, 1 md k</td>
</tr>
<tr>
<td>Fracture Spacing</td>
<td>0.2 ft</td>
</tr>
<tr>
<td>Rock Compressibility</td>
<td>Matrix and Fracture:</td>
</tr>
<tr>
<td></td>
<td>Reference Pressure</td>
</tr>
<tr>
<td></td>
<td>1100 psia</td>
</tr>
<tr>
<td></td>
<td>Rock Compressibility</td>
</tr>
<tr>
<td></td>
<td>1.0x 10^-6 1/psia</td>
</tr>
<tr>
<td>EOS Model</td>
<td>Peng-Robinson</td>
</tr>
<tr>
<td>Library Components</td>
<td>Methane</td>
</tr>
<tr>
<td>Constant Reservoir Pressure</td>
<td>113 F</td>
</tr>
<tr>
<td>Rock Fluid Data-Grid Properties</td>
<td></td>
</tr>
<tr>
<td>Maximal Adsorbed mass (CH4)</td>
<td>Matrix: 0.2845</td>
</tr>
<tr>
<td></td>
<td>Fracture: 0</td>
</tr>
<tr>
<td>Langmuir Adsorption (CH4)</td>
<td>Matrix: 1.48E-03</td>
</tr>
<tr>
<td></td>
<td>Fracture: 0</td>
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<tr>
<td>Rock Density</td>
<td>Matrix: 89.63 lb/ft3</td>
</tr>
<tr>
<td></td>
<td>Fracture: 89.63 lb/ft3</td>
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<tr>
<td>Coal Sorption time(CH4)</td>
<td>Matrix: 50 days</td>
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<tr>
<td></td>
<td>Fracture: 50 days</td>
</tr>
<tr>
<td>Water Saturation</td>
<td>Matrix: 0.005</td>
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<tr>
<td></td>
<td>Fracture: 1</td>
</tr>
<tr>
<td>Pressure</td>
<td>Critical Desorption</td>
</tr>
<tr>
<td></td>
<td>Pressure: 300 psia</td>
</tr>
<tr>
<td></td>
<td>Fracture: 600 Psia</td>
</tr>
<tr>
<td>Gas Composition (CH4)</td>
<td>Matrix: 1 Fracture: 1</td>
</tr>
<tr>
<td>Constraints</td>
<td></td>
</tr>
<tr>
<td>Minimum Bottom Hole Pressure</td>
<td>50 psia</td>
</tr>
<tr>
<td>Maximum Gas Rate</td>
<td>350,000 ft3/day</td>
</tr>
<tr>
<td>Well Length</td>
<td>1100 ft</td>
</tr>
</tbody>
</table>
direction were changed at a ratio of 1:3 (1/3 of the maximum permeability; i = 10 md, j = 3.3 md and, k = 1 md). Permeability of 20 md is considered as extreme case for the Northern Appalachian basin. It was included in this study to fully demonstrate the effect of permeability on the type curves.

The horizontal well length is changed for all the different areas and this change is based on a ratio of 11:38, 15:38, and 30:38 to study the effect of ratio of well length to reservoir length at different areas. Table 3.2 summarizes the parameters and their ranges.

---

**Figure 3.1: Horizontal Well in a Box-shaped Drainage Volume (Babu and Odeh, 1989)**

**Table 3.2: Parameters range employed during this study**

<table>
<thead>
<tr>
<th>Variable</th>
<th>Range</th>
<th>Values Used</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fracture Permeability I, j, k (md)</td>
<td>5 - 20</td>
<td>5i, 1.7j, 1k</td>
</tr>
<tr>
<td>Fracture Porosity (%)</td>
<td>1.5 - 3</td>
<td>1.5, 2, 2.5, 3</td>
</tr>
<tr>
<td>Area (Ac)</td>
<td>160 - 320</td>
<td>160, 240, 320</td>
</tr>
<tr>
<td>Thickness (ft)</td>
<td>5 - 20</td>
<td>5, 10, 15, 20</td>
</tr>
<tr>
<td>Critical Desorption Pressure (psia)</td>
<td>300 - 600</td>
<td>300, 400, 500, 600</td>
</tr>
<tr>
<td>Initial Fracture Pressure (psia)</td>
<td>300 - 600</td>
<td>300, 400, 500, 600</td>
</tr>
<tr>
<td>Flowing Bottomhole Pressure (psia)</td>
<td>50 - 100</td>
<td>50, 75, 100</td>
</tr>
<tr>
<td>Changing the Ratio of Well length to Reservoir Length</td>
<td>1100ft-4300ft</td>
<td>11:38, 15:38, 30:38</td>
</tr>
</tbody>
</table>
3.2 Dimensionless Groups for Water Production Type Curve

Set of dimensionless rate and time were utilized by Bhavsar\textsuperscript{20} to develop type curve for water. They do not require reservoir properties and they are presented as followed. The water dimensionless rate and time were defined as:

\[ q_{WD} \sim \frac{q_w}{q_{iw}} \]  
\( (7) \)

\[ t_{WD} \sim \frac{t \times q_{iw}}{W_i} \]  
\( (8) \)

Where, \( q_{iw} \) represents the initial (maximum) water rate, and \( W_i \) is the initial water in the cleat system, which can be calculated by the following equation:

\[ W_i = 43560 \times A \times h \times \phi_f \times S_{wi} \]  
\( (9) \)

Where, \( A \) is the reservoir area in acres, \( h \) is the thickness of coal in ft, \( \phi \) is the cleat system porosity and \( S_{wi} \) is the initial cleat system water saturation.

3.3 Determination of initial (maximum) water rate \( q_{iw} \)

The most important parameter in developing the type curve are to estimate \( q_{iw} \) and \( W_i \) for water production. Estimation of \( q_{iw} \) is complicated for water. An extensive literature survey was performed to see if theories of a conventional reservoir can be applied to CBM reservoir. Since coal cleat is filled with water in the early stages, CBM reservoir act as single phase unsteady state. Hence we applied the single phase liquid unsteady state solution to find the initial water rate \( q_{iw} \). The following equation developed by Joshi\textsuperscript{25} used to calculate \( q_{iw} \).
3.4 Development and verification of dimensionless groups for type curve generation.

The development of a generalized correlation for dimensionless peak water rate in horizontal wells follows the same procedure as in vertical wells as discussed earlier. The dimensionless groups are essentials for generating the production type curve to analyze and predict CBM performance. These dimensionless variables represent the values for the ordinate and abscissa of the type curve. Knowing the effect of two-phase flow through the porous media in CBM, it is required to carefully analyze the impact of each variable of the equation in the behavior of the gas production type curve.

The following equation defines the dimensionless peak water rate for horizontal wells in CBM reservoirs.

\[
q_{iw} = \frac{\sqrt{k_y \times k_z \times L_w \times (P_i - P_{wf})}}{162.6 \times \beta \times \mu \times [\log(\sqrt{\frac{k_y \times k_z \times t}{\phi \times \mu \times c_t \times r_w^2}) - 3.23]}
\]  

\[ (10) \]

From this studies it was concluded that there is a linear relation between \( q_{(peak)wd} \) and various reservoir parameters such as permeability \( k \), porosity \( \phi \), critical desorption pressure \( P_{(matrix)} \), fracture pressure \( P_{(frac)} \), Langmuir pressure \( P_L \) and Langmuir volume \( V_L \).

3.5 Multiple Linear Regression Analysis

Linear regression analysis is a statistical analysis used for forecasting. Regression analysis estimates relationship between variables, so that a given variable can be predicted from one or more other variables. A correlation was developed to calculate dimensionless water rate using reservoir properties. This
correlation can be used to calculate dimensionless water rate in the absence of reservoir production data.

3.6 Validation

In the last stage in order to validate the accuracy of the production type curve that were constructed, the identification of the curve with the largest gap between the dimensionless curves and the average curve for each property was analyzed. Then the squares of Pearson and the errors between those curves were calculated by selecting the water rate at similar times. In that way, the maximum difference (error) was measured and evaluated for the Ten properties studied.

In addition to this, simulator runs were used to generate the production history for two cases. The inputs used were values within the range that characterize the Northern Appalachian Basin properties, but using a combination of inputs completely different than the ones used for the runs made before.

The production history simulated by CMG for the first 25 years of production was used to obtain dimensionless values in order to employ the type curve. Then, the prediction of future production rate from the type curve and the future rates generated by the numerical simulator were compared. This step was performed in order to guarantee the degree of uniqueness of the dimensionless group used in the construction of the CBM production type curve.

At the same time, evaluation of peak water rate was done in order to present an alternative procedure to predict CBM water production without having any production data. The impact of the reservoir properties (area, permeability, thickness, porosity, initial matrix pressure, initial fracture pressure, flowing bottomhole pressure, and differential pressure) on peak water rate was studied. Dimensionless group was presented (equation 11) based on Darcy's Law definition. Flow rate generally depends on thickness, time, porosity, well length, permeability and differential pressure. Therefore, these properties and peak
water rate were used as first approach to get the dimensionless group. These dimensionless flow rates were plotted against the reservoir properties studied before in order to scrutinize the impact of each property. The properties whose effect was not taken in account by the dimensionless group were identified. An evaluation of those properties and peak water rate behavior was performed.

\[
q_{(peak)W}^{D} = \frac{q_{(peak)W} \times 162.6 \times \beta \times \mu \times \left[ \log \left( \frac{\sqrt{K_x \times K_y \times t}}{\phi \times \mu \times c_i \times r_w} \right) \right] - 3.23}{\sqrt{K_y \times K_z} \times L_w \times (P_i - P_{wf})} \tag{11}
\]

This approach was conducted with the purpose of defining a correlation to estimate the value of \(q_{peak}\). Then, knowing some of the reservoir properties \(q_{D}\) value can be found from the correlation (equation 12) developed. Then, solving equation 11 for \(q_{peak}\), the prediction of water production can be also estimated if there is not production data available. The value of peak water rate was compared with the maximum water rate obtained from the numerical simulator to complete the validation process.

### Table 3.3: Case Study Inputs

<table>
<thead>
<tr>
<th>PARAMETERS</th>
<th>Case 1</th>
<th>Case 2</th>
<th>Case 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fracture Permeability (md)</td>
<td>(K_x=7, K_y=2.3, K_z=1)</td>
<td>(K_x=12, K_y=4, K_z=1.3)</td>
<td>(K_x=17, K_y=5.6, K_z=1.8)</td>
</tr>
<tr>
<td>Fracture Porosity (%)</td>
<td>1.8</td>
<td>2.2</td>
<td>2.7</td>
</tr>
<tr>
<td>Thickness (ft)</td>
<td>8</td>
<td>12</td>
<td>18</td>
</tr>
<tr>
<td>Critical Desorption Pressure (psia)</td>
<td>350</td>
<td>450</td>
<td>550</td>
</tr>
<tr>
<td>Initial Fracture Pressure (psia)</td>
<td>525</td>
<td>425</td>
<td>325</td>
</tr>
<tr>
<td>Flowing Bottomhole Pressure (psia)</td>
<td>60</td>
<td>80</td>
<td>90</td>
</tr>
<tr>
<td>Langmuir Pressure (psia)</td>
<td>300</td>
<td>600</td>
<td>900</td>
</tr>
<tr>
<td>Langmuir Volume (Scf/ton)</td>
<td>250</td>
<td>500</td>
<td>750</td>
</tr>
</tbody>
</table>
Chapter IV
Results and Discussion

The purpose of this study has been to develop and evaluate a reliable method for predicting the production performance of the horizontal wells without the need for costly and time-consuming computer simulations. The results of the impact of the various parameters studied are discussed below. Figure 4.1 shows the type curve for the base model.

![Base Model (Log-Log)](image)

Figure 4.1: Water Type Curve for Base Model (Horizontal Well)

The second set of simulations took into account the flowing BHP (Bottomhole Pressure). The BHP was changed to different values to determine its impact on the set of dimensionless equations. The BHP was run on values ranging from 50-
100 psia. As shown in Figure 4.2, it was concluded that bottomhole flowing pressure does not have effect on shape of the type curve.

![Flowing Bottom Hole Pressure](image)

**Figure 4.2: Effect of Bottomhole Flowing Pressure on the Shape of the Type Curve.**

The third set of simulations took into account the effect of porosity on the production from horizontal CBM wells. The porosity varied from 1.5% to 3%. At early stages, the time-water-peak and the late performance coincide with the average curve. By seeing the production behavior in log-log scale (Figure 4.3), the curves experience a small gap between them at the very early time of depletion. However, the curves converge right before and after the peak occur. The maximum error calculated between the curve with the largest gap and the average curve was less than 10%. It was concluded that fracture porosity does not have effect on shape of the type curve.
The fourth set of simulations was performed to evaluate the influence of coal thickness in CBM reservoirs performance. The thickness varied from 6 to 15 ft. At early stages, the time-water-peak and the late performance coincide with the average curve. By seeing the production behavior in log-log scale (Figure 4.4), the curves experience a small gap between them at the very early time of depletion. However, the curves converge right before and after the peak occur. The maximum error calculated between the curve with the largest gap and the average curve was less than 10%. It was concluded that thickness does not have effect on shape of the type curve.
The fifth set of simulations includes the variation of the critical desorption pressure. The impact of the pressure in the CBM production is considered critical and it needs to be tested to evaluate the behavior of the water depletion. The critical desorption pressure varied in a range of 300 to 600 psi. As shown in Figure 4.5, it was concluded that critical desorption pressure does have effect on shape of the type curve.

The sixth set of simulations includes the variation of the fracture pressure. The fracture pressure varied in a range of 300 to 600 psi. As shown in Figure 4.6, it was concluded that fracture pressure does have effect on shape of the type curve.
Figure 4.5: Effect of Critical Desorption Pressure on the Shape of Type Curve.

Figure 4.6: Effect of Initial Reservoir Pressure on Shape of Type Curve
The curves for permeability converge at a later stage of the reservoir. As we can see from the plot that even though there is deflection in the type curves, the type started at a common point and ended tapered at the end. At early stages, By seeing the production behavior in log-log scale (Figure 4.7), the curves experience a small gap between them at the very early time of depletion. The maximum error calculated between the curve with the largest gap and the average curve was less 10%. For this case, the dimensionless groups generate a curve with reasonable results as far as sorption time is concerned. It was concluded that Permeability does have effect on shape of the type curve.

![Permeability Variation](image)

**Figure 4.7: Effect of Permeability ($k_x$) on Shape of Type Curve.**

The eight set of simulations considers the influence of Langmuir pressure on the CBM water production behavior. In this study, several Langmuir pressure were used. As shown in Figure 4.8, it was concluded that Langmuir Pressure does not have effect on shape of the type curve.
The ninth set of simulations considers the influence of Langmuir volume on the CBM water production behavior. As seen in Figure 4.9, type curves start at a common point and tapered to a common point, it was concluded that Langmuir Volume does not have effect on shape of the type curve.

In the Tenth set of simulations, the horizontal length is changed for all the different areas and this change is based on a constant ratio as given on table 3.2. As seen in Figure 4.10, it was concluded that change in horizontal well length to length of reservoir does not have effect on shape of the type curve.

The eleventh set of simulations corresponds to the variation of both initial desorption and reservoir pressure by the same value. Simulations were performed testing these properties for Desorption and reservoir pressures of 400 and 500psi.
As seen in Figure 4.11, it was concluded that variation of both initial desorption and reservoir pressure by the same value does not have effect on shape of the type curve.

Figure 4.9: Effect of Langmuir Volume on Shape of Type Curve

Figure 4.10: Effect of Ratio of Horizontal Length to Side of Reservoir on the Shape of the Type Curve
After all the parameters have been changed and an evaluation of their impact on the dimensionless equations has been made, average type curve was developed for combined effect of desorption pressure and reservoir pressure since they have a significant impact on the shape of the type curve. The average type curve is shown in Figure 4.12

4.2 Multiple Linear Regression Analysis

A linear regression analysis was done to develop a correlation. As first step all the parameters of interest were correlated in various combinations with an $R^2$ value of 0.86.

$$q_{\text{peak}} = h \times (4.4E / \text{02}) - k \times (9.7E / \text{03}) - k \times (2.5E / \text{03})$$

$$-K \times (1.9E / \text{02}) - A \times (3.3E / \text{04}) - L \times (2.4E / \text{03})$$

$$-F \times (2.3E / \text{03}) - P \times (2.9E / \text{04}) - M \times (1.2E / \text{03})$$

$$-\eta \times (8.2E \text{00}) - V \times (3.3E / \text{04}) - P \times (4.8E / \text{03}) - 1.5$$

(12)
4.3 Verification

By using the above dimensionless correlation (equation 12), and doing reverse calculation of equation 11, the peak water rate for any case in a coalbed methane reservoir can be calculated. With production type curves, an assumption that future production can easily determined with some thought and few calculations can be made. In order to estimate the future production from CBM wells in which no production data is available a new equation had to be adopted and a value of $q_{peak}$ could be calculated just from knowing few parameters.

This approach was validated by comparing the peak water rate from the correlation and from the simulated data for case one, two and three.
Table 4.1: Case Study

<table>
<thead>
<tr>
<th></th>
<th>Case 1</th>
<th>Case 2</th>
<th>Case 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>$q_{\text{peak}}$ Value from simulator</td>
<td>1354.36</td>
<td>2091.59</td>
<td>3125.73</td>
</tr>
<tr>
<td>$q_{\text{peak}}$ Value from back calculation</td>
<td>1462.70</td>
<td>1861.15</td>
<td>3052.26</td>
</tr>
<tr>
<td>Error % in $q_{\text{peak}}$ calculation</td>
<td>7.4%</td>
<td>9%</td>
<td>3%</td>
</tr>
</tbody>
</table>

For case one, a peak water rate of 1354.36 Bbl/day was found by using the simulator and 1462.7 Bbl/day by applying the numerical simulator developed. For case two, a peak water rate of 2091.59 Bbl/day was found by using the simulator and 1861.15 Bbl/day by applying the numerical simulator. For case three, a peak water rate of 3125.73 Bbl/day was found by using the simulator and 3052.26 Bbl/day by applying the numerical simulator. As it can be seen, the correlation provides a reasonable estimation of peak water rate in order to be able to use the production type curves without starting the water production. This correlation allows the use of the type curve for water production forecast in order to evaluate the feasibility and economics between several projects to facilitate the decision-making.

Figure 4.13 Comparison of the Predicted Water Production (Case 1)
Figure 4.14 Comparison of the Predicted Water Production (Case 2)

Figure 4.15 Comparison of the Predicted Water Production (Case 3)
From the results, the predicted production rates from the type curves closely match those from the simulator. \( q_{(peak)D} \) Value was calculated for the case study by using the correlation equation developed and then the values of \( q(peak)w \) was computed using the calculated value of \( q_{(peak)D} \) in equation 11. The comparison of the calculated and estimated value of \( q_{(peak)W} \) for the case study, gave a maximum error of 8 percent and this leads to the conclusion that the correlation developed for \( q_{(peak)D} \) can provide reliable results.
Chapter V
Conclusions and Recommendation

The following conclusions and recommendations were made.

1. Average production type curves for water in horizontal CBM reservoirs were developed that could be used by the independent producers to evaluate and predict production data.

2. Fracture pressure, and critical desorption pressure were found to have significant influence on the type curve.

3. A reliable correlation for predicting the peak water rate was developed that allowed the type curve to be used as a tool for predicting production.

4. The comparison of the model prediction and type curve prediction indicated an error of 8 percent, which is within reasonable engineering tolerance.

This study can be used in the development and implementation of new technology and growth in unconventional CBM gas reservoirs in the Northern Appalachian Basin.

Recommendations

Since relative permeability data is an important parameter for the water production from CBM wells, it is recommended to study this variable in detail in developing correlations for both gas and water prediction.
References

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Appendix

Langmuir Volume ($V_L$) and Langmuir Pressure ($P_L$) range employed in this study.

\[
\frac{x}{453} \times 379 \times 2000 = V_L \\
\frac{1}{x} = P_L
\]

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<th>$V_L$</th>
<th>$X$</th>
<th>$P_L$</th>
<th>$X$</th>
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<tbody>
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<td>100</td>
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<td>1000</td>
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