Abstract

Unconventional oil reservoirs, such as Bakken, have gained considerable interest in recent years because they have become a great resource to produce oil and gas to meet the energy needs of North America. Performance prediction from these tight reservoirs is a challenge because of the complexity of reservoir flow, well completion, and fracture stimulation techniques. Elm Coulee field, in Bakken, is an example of such unconventional reservoirs and is located in Richland County, Montana. The field was drilled using both vertical and horizontal wells, but in recent years the use of horizontal wells has become the standard practice. The objectives of this study were: (1) evaluate the long-term (7 to 10 years) performance of horizontal wells in Montana Elm Coulee, (2) develop a better understanding of how to predict the long-term performance of younger Bakken fields in North Dakota based on the Elm Coulee experience.

Arps hyperbolic decline curve analysis was used as the main forecasting approach. In Arps analysis,

\[ q(t) = q_i (1 + bD) \frac{1}{1-b} \]

where \( q \) is the flow rate, \( D \) is the decline rate, and \( b \) is the decline exponent. It will be demonstrated that forecasts using a constant \( b \) overpredict well performance. To match the long-term performance of Elm Coulee wells, the numerical value of \( b \) had to be decreased with time.

Analytical approaches (log-log type-curve diagnostic plots and the Fetkovich log-log normalized plot) were also used to decipher the flow regimes, and to determine the varying decline rate from long-term producing wells in Elm Coulee Field. In addition to analytical modeling, numerical modeling was also used because it is more comprehensive in utilizing a larger set of reservoir parameters such as reservoir heterogeneity variations. This is very useful in transferring what we learned from the long-term performance of Elm Coulee Montana wells to the short-term performance of wells in North Dakota by addressing both geology and reservoir property differences between these fields.

Introduction

Arps decline curve analysis has been extensively used to estimate reserves from depletion drive oil and gas reservoirs since the 1950s. The method utilizes the rate equation, \( q(t) = q_i (1 + bD) \frac{1}{1-b} \), where \( q \) is the flow rate, \( D \) is the decline rate given by \( D = -d \ln q/\text{dt} \), and \( b = d(1/D)/\text{dt} \). It can be shown that \( D = aq^b \) where \( b \) is a number between zero and one for hyperbolic decline, \( b \) equal to zero represents exponential decline and \( b \) equal to one is harmonic decline.

It will be demonstrated that forecasts using a constant \( b \), obtained from the early transient flow, overpredicts well performance for wells that have long transient flow periods. To match the long-term performance of Elm Coulee wells, the numerical value of \( b \) had to be decreased with increasing time. A theoretical reason in support of this action is given below:

Yousef et al (2006) presented an analytical-numerical solution of a capacitance model to infer interwell connectivity from well rate data. Their method should work effectively for high connectivity conventional reservoirs. Nonetheless, the capacitance model can be used in low permeability, depletion-type, unconventional reservoirs, to explain why the hyperbolic decline
exponent does not remain constant and why it decreases with time. This simple concept is consistent with field observations of production rate decline in Elm Coulee field as reported in this paper.

We start with the following equations:

\[ q(t) = J(\bar{p} - p_w) \]  \hspace{1cm} (1)
\[ -q(t) = \phi c V_R \frac{\partial \bar{p}}{\partial t} \]  \hspace{1cm} (2)

where,

\( q(t) \) is production rate, \( J \) productivity or well index, \( \bar{p} \) average pressure in the drainage volume of the well, \( p_w \) bottom-hole well pressure, \( V_R \) drainage volume of the well, \( \phi c \) specific storage coefficient, and \( t \) time. For analytical solution to the capacitance model, \( J \) and \( V_R \) are assumed constant while \( p_w \) can be either constant or varying with time. When bottom-hole pressure is variable, the solution involves a convolution integral. This solution can be used to explain why flowrate can increase with lowering of the bottom-hole pressure. For constant \( J \), \( V_R \) and \( p_w \), the solution of Eqs. 1 and 2 is the exponential decline of flowrate versus time (Yousef, et al, 2006).

\[ q(t) = q(t_o) e^{-\frac{(t-t_o)}{\tau}} \]  \hspace{1cm} (3)

where,

\[ \tau = \phi c V_R / J \]  \hspace{1cm} (4)

Taking logarithm of Eq. 3 will lead to a straight line with slope \(-1/\tau\), which is the same as the exponential decline rate, \(-D\), in the conventional nomenclature of decline curve analysis (Ilk, et al, 2008). The conventional decline exponent \( b \) is defined below:

\[ b = \frac{d}{dt} (1/D) = \frac{d}{dt} (\phi c V_R / J) \]  \hspace{1cm} (5)

In exponential decline behaviour \( b \) is zero, and in hyperbolic decline behaviour \( b \) is a positive number between zero and one. Thus, when drainage volume, well index, and specific storage coefficient are constant, \( b \) becomes zero, which is consistent with the definition of exponential decline.

In low-permeability reservoirs, both \( V_R \) and \( J \) vary with time less intensely than in high-permeability reservoirs. From transient flow theory, it can be shown that \( \phi c V_R / J = \alpha L_d^2 \). When \( L_d^2 \) is computed from the drainage distance-transient time equation we obtain \( \phi c V_R / J = \beta t \) where \( \beta \) is constant. Therefore, from Eq. 5, \( b \) becomes a constant.

However, if \( \phi c V_R / J \) is not a function of time, \( b \) becomes zero. But, reservoir flow indicates otherwise because both the numerator and denominator change at different rates with time. In fact, drainage volume contribution grows more slowly than the well index as time increases. Thus, while \( b \) versus time is a positive function with a positive slope, its slope will decrease with time because of the lack of perfect reservoir connectivity. The decrease in the slope of \( b \) can be considered as a measure of reservoir heterogeneity, loss of pore volume connectivity (reservoir production conformance) and/or pore volume compartmentalization away from the wellbore.

The reserve estimation in unconventional reservoirs is a challenge because the commonly used Arps empirical rate-decline equation does not capture the decreasing trend of \( b \) during transient flow period. As background, Arps equation is:
\[ q(t) = \frac{q_i}{(1 + bD_i t)^{1/b}} \]  

(6)

where the decline rate, \( D \) is:

\[ D = -\frac{1}{q} \frac{dq}{dt} \]  

(7)

and \( b \), the time derivative of the reciprocal of the decline rate, is:

\[ b = \frac{d(1/D)}{dt} = -\frac{d}{dt} \left( \frac{q}{dq/dt} \right) \]  

(8)

Using Eqs. 7 and 8, it can be show that

\[ D = aq^b \]  

(9)

A study by Rushing et al. (2007) presents the errors in estimating reserves using hyperbolic decline for constant \( b \) values. This issue was also addressed by Ilk et al. (2008) recognizing that the common practice of using constant \( b \) over the well life needed to be constrained to minimize forecasting unrealistic reserves.

Rushing et al. used the terminal decline concept so that the hyperbolic curve generated by using constant \( b \) value would be limited by changing the hyperbolic relation to exponential when the decline rate reaches the pre-defined terminal rate, \( D_{\text{min}} \).

The biggest concern with this method is estimation of \( b \) value for transient flow regime and terminal decline rate which also creates inconsistent reserve estimations with high uncertainty due to pre-defined parameters. To get around this problem, we used Arps standard decline rate equation until \( D \) reaches \( D_{\text{min}} \) thereafter, we used purely the exponential decline equation with the decline exponent equal to \( D_{\text{min}} \). Figure 1 presents this approach, where the figure shows the sensitivity of \( b \) values and terminal decline rate, \( D_{\text{min}} \), on production. Furthermore, the figure shows a range of uncertainty in the estimated ultimate recovery, \( EUR \), especially early in the well life. As \( b \) increases, the \( EUR \) values increase as shown on the figure for terminal decline rates of 4 -10 \% per year.

Elm Coulee Field History

Elm Coulee field was discovered in 2000. It mainly produces from the middle member of the Bakken formation (10 to 35 ft) in Williston basin, Montana. The Montana Bakken consists of three members: upper shale, middle silty dolostone and lower siltstone. A typical well log of Elm Coulee is shown in Fig. 2.

Our goal is to transfer what we learn from Elm Coulee long-term production history to the near fields in North Dakota. However, the producing Bakken middle member in North Dakota (30 to 50 ft) is a marine sandstone or siltstone with considerable percentages of carbonate grain and cement. The Elm Coulee Bakken formation is slightly overpressured (0.52 psi/ft) whereas the North Dakota Bakken is overpressured (0.8 psi/ft).

The Elm Coulee field is developed with horizontal drilling using a single-lateral, a dual-lateral or multi-laterals on 640- and 1280-acre spacing. The orientation of horizontal wells is east-west or north-south. Understanding the geological, reservoir and completion differences between Bakken formations in Elm Coulee and North Dakota is the key to effective evaluation and forecast of well performance in these unconventional reservoirs. Although many theoretical studies have been published on estimating reserves in unconventional reservoirs, their application to the real world situations is limited because of lack of extensive history. Furthermore, the horizontal well technology and stimulation practices are continuously improving, which should have a major effect on well performance.

In this study, horizontal wells drilled between 2000 and 2003 in the Elm Coulee field are analyzed to observe the decline characteristic of both transient and boundary dominated flow regimes. The monthly field data for each well is used to make rate-time and rate-time-pressure analysis. The workflow starts with decline curve analysis and continues with the application
of analytical and numerical methods to better define the current decline parameters in the Elm Coulee field. An example well from Elm Coulee field, which has been on production for nine years, is used to illustrate each analysis technique.

Unconstrained $b$ values and a terminal decline rate of 6 % per year are used to match the full rate history of each well. To illustrate the change in $b$ values during transient flow regime, the example well life is divided into 12, 48 and 72 months and decline curve analysis is applied to each subset of data starting from the initial production to estimate ultimate recovery as shown in Figure 3. As noted, $b$ decreases with increasing time -- yielding lower reserves estimates.

The terminal decline rate concept, using $D_{\text{min}}$, was also used. However, the use of $D_{\text{min}}$ parameter is ambiguous because there is never enough history to estimate this terminal decline rate for hydraulically fractured horizontal wells.

A non-hyperbolic, power-law exponential decline rate relation, Eq.10, introduced by Ilk et al. (2008), was used to calculate the changes in $b$ and $D$ values for the example well exhibiting transient flow regime (Fig. 4). The EUR projected by this method is around 325,000 bbls.

$$q(t) = \hat{q}_t \exp\left(D_{\text{min}} t - \hat{D}_{\text{min}} t^b\right)$$

(10)

**Analytical Methods**

The current flow regime of the Elm Coulee wells are identified using log-log type-curve diagnostic plots and the Fetkovich log-log normalized plots. The Fetkovich log-log normalized plot helps to determine the flow regime of a well exhibiting transient (infinite acting period) or boundary-dominated (depletion period) flow regimes as shown in Figure 5. As explained in the study of Fetkovich et al. (1996), transient data used with Arps equations can yield $b>1$ and highly emphasized that Arps equations are only valid for depletion period. In addition, log-log type-curve diagnostic plot is used to decipher well flow regimes from normalized pressure and normalized pressure derivative response from drawdown data. As shown in Figure 5 the normalized pressure and derivative exhibits half slope during transient period while boundary dominated flow has a unit slope from both pressure and derivative responses. As shown in Figure 6 the example Elm Coulee with nine years of production continues to exhibit linear flow.

All the wells with history from 7-10 years in the Elm Coulee field were analyzed using analytical methods and it was observed that the wells are still in transient flow regime. Therefore the terminal decline for these wells cannot be determined. However each well’s apparent exponential decline was calculated based on the last 12 month of data and can be used as an indication of the upper limit for this completion type and reservoir parameters. These results are illustrated in Figure 7.

Because Elm Coulee wells are in boundary-dominated flow regime, we had to include vertical and horizontal completions from North Dakota that exhibit boundary dominated flow. These wells provide additional insight into the terminal decline rate for the North Dakota Bakken reservoir. The average terminal decline obtained from these wells was found to be 3.3 % per year. The distribution of their results is compared to the Elm Coulee results in Figure 8. It is believed that these results provide a reasonable lower bound for the estimation of terminal decline. The variability in the North Dakota results is a reflection of the variable reservoir and completion parameters. The current completion practice employed in the Bakken will also have an effect on the terminal decline rate. In an attempt to quantify these effects a reservoir simulator was constructed to test each parameters effect on terminal decline.

**Reservoir Simulation**

A finite-difference, single-well model was built to address the effect of changing reservoir and completion parameters on terminal decline in Elm Coulee. The base case represents a horizontal well with transverse fractures producing from the center of 1280-acre reservoir which matches the average production history of the selected wells and average current decline rate (11 % per year). In order to capture the stimulated reservoir volume around the well and match the historical production from the field, the effective permeability is decreased away from the wellbore as shown in Fig. 9. The core analysis and drill stem test results from four Elm Coulee wells provided by Pramudito (2009) are used for the average permeability and porosity in the initial model. The parameters for the base case are listed in Table 1. Based on these reservoir parameters and for a fracture stimulated well the model generated terminal decline was 3.5 % per year (Fig. 10).
Table 1- Model parameters

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Formation Top, ft</td>
<td>10,500</td>
</tr>
<tr>
<td>Gridded area, Acres</td>
<td>1280</td>
</tr>
<tr>
<td>Initial Reservoir Pressure, psi</td>
<td>5,000</td>
</tr>
<tr>
<td>Effective Porosity, %</td>
<td>5.0</td>
</tr>
<tr>
<td>Net Pay, ft</td>
<td>35</td>
</tr>
<tr>
<td>Effective Permeability, md</td>
<td>0.05</td>
</tr>
<tr>
<td>Oil Formation Volume Factor, rb/STB</td>
<td>1.425</td>
</tr>
<tr>
<td>Reservoir Temperature, °F</td>
<td>240</td>
</tr>
<tr>
<td>Oil Viscosity, cp</td>
<td>0.36</td>
</tr>
<tr>
<td>Fracture Half-length, ft</td>
<td>300</td>
</tr>
<tr>
<td>Fracture Conductivity, md-ft</td>
<td>75</td>
</tr>
<tr>
<td>Fracture Spacing, ft</td>
<td>1000</td>
</tr>
</tbody>
</table>

The conceptual reservoir simulator was used to perform a sensitivity analysis on important reservoir and completion parameters. The uncertainty parameters for sensitivity analysis are determined by identifying the average geology and reservoir properties expected in the Elm Coulee field and in North Dakota. The comparison of average reservoir and fluid properties are summarized in Table 2. Considering the main differences in reservoir, geology and completion, sensitivity parameters are determined including drainage area, lateral length, effective permeability, porosity, fracture spacing and fracture conductivity. The results are shown in Figure 11. As observed, both the volumetric parameters and the completion play important roles in defining decline characteristics.

Table 2- Average reservoir and fluid properties in Bakken

<table>
<thead>
<tr>
<th>BAKKEN</th>
<th>Properties</th>
<th>Elm Coulee</th>
<th>North Dakota</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reservoir</td>
<td>Reservoir Pressure, psi</td>
<td>5000</td>
<td>8000</td>
</tr>
<tr>
<td></td>
<td>Reservoir Temperature, °F</td>
<td>240</td>
<td>240</td>
</tr>
<tr>
<td></td>
<td>Permeability, md</td>
<td>0.05-0.5</td>
<td>0.001-0.06</td>
</tr>
<tr>
<td></td>
<td>Porosity, %</td>
<td>5-10</td>
<td>4-6</td>
</tr>
<tr>
<td></td>
<td>Middle Bakken Thickness, ft</td>
<td>10-35</td>
<td>30-50</td>
</tr>
<tr>
<td>Fluid</td>
<td>API, °</td>
<td>42</td>
<td>42</td>
</tr>
<tr>
<td></td>
<td>Gas-Oil Ratio, Mscf/bbls</td>
<td>500</td>
<td>500-800</td>
</tr>
<tr>
<td></td>
<td>Viscosity, cp</td>
<td>0.36</td>
<td>0.3-0.5</td>
</tr>
</tbody>
</table>

The results in Figure 11 highlight the importance of incorporation of analytical and numerical modeling in the determination of an appropriate terminal decline and that a single number should not be used for the development especially if the completion practices are changing in the field. It is with out question that the early time performance of the Bakken wells can be improved by increasing the number of fracture stages and if evaluated with a constant terminal decline the projected ultimate recovery will increase. In an attempt to further quantify how completion strategies may affect the terminal decline in the North Dakota Bakken development we propose the following work flow:

1. Evaluate the vertical well performance of historical Bakken completions to determine reservoir flow capacity, effective drainage area and effective fracture half length.
2. Translate the drainage area into an appropriate drainage area for a horizontal well with multiple transverse fractures. (Joshi 1991)
3. Incorporate these results into an appropriate analytical or numerical simulator.
4. Develop production forecasts for multiple completion types.
5. Evaluate long-term performance to determine the effective terminal decline.
The following example is presented to illustrate the proposed work flow. A vertical well producing from the Bakken formation in North Dakota was used for the production analysis to determine the required reservoir and completion parameters. The example well was found to have an effective drainage radius of 2,500 ft, reservoir flow capacity of 1.2 md-ft and an effective fracture half length of 250 ft. The terminal decline of our example well is 9.8% per year. Based on these results a horizontal model was constructed as illustrated in Figure 12. This model was used to determine a relationship between the number of effective transverse fracture stimulations and the terminal decline.

The results of our analysis indicate that for a given set of reservoir parameters the terminal decline is a function of the number of effective transverse fractures. For this case if the spacing between fractures is greater than 5,000 ft the resulting terminal decline is less than the vertical well’s terminal decline. As the distance is decreased the terminal decline increases. These results were obtained by using an analytical model and are consistent with the results obtained from numerical simulation. This study also found a positive relationship between the first year effective decline and the final terminal decline. The results of this analysis are summarized in Table 3. Figure 13 compares the analytical model’s projected ultimate recovery compared to a decline curve projection of ultimate recovery based on the well’s thirty day production rate.

<table>
<thead>
<tr>
<th>Number of Fractures</th>
<th>30-Day Rate (bbl/d)</th>
<th>Terminal Decline (%/year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>114</td>
<td>4.2</td>
</tr>
<tr>
<td>4</td>
<td>227</td>
<td>9.4</td>
</tr>
<tr>
<td>8</td>
<td>454</td>
<td>12.8</td>
</tr>
<tr>
<td>16</td>
<td>794</td>
<td>13.4</td>
</tr>
<tr>
<td>32</td>
<td>711</td>
<td>13.8</td>
</tr>
<tr>
<td>64</td>
<td>642</td>
<td>14.6</td>
</tr>
</tbody>
</table>

This example assumes that the reservoir and completion performance from the vertical well represents the average properties and that these properties can be used to predict horizontal well performance. If this assumption is not valid we would recommend a modification of the proposed workflow that replaces the vertical well performance with the construction of a dynamic model that reflects the current view of the reservoir and completion parameters. The resulting models can then be used to perform the sensitivity analysis proposed in the remainder of the workflow.

In many cases vertical well performance is not available to calibrate reservoir and completion parameters. In these cases we would recommend a modification to the proposed workflow to incorporate the current reservoir and completion geometries into the dynamic model to predict performance. These results should be tested against actual horizontal performance in the area and then used to evaluate decline parameters including terminal decline.

Conclusions

The conclusions from this study are presented below:

- Arps decline rate equation does not predict long-term well performance accurately when it is only applied to the early production data from wells which have extended transient flow periods.
- The capacitance model can be used to describe the loss of reservoir pore volume connectivity as the well drainage volume expands during reservoir life.
- It is necessary to determine the correct terminal decline characteristics of wells in low-permeability reservoirs.
- It is imperative that both analytical and numerical modeling be used in characterizing the long-term performance of unconventional reservoirs. In this regard, understanding the relationship between reservoir, completion, and decline curve parameters is of paramount importance.

Acknowledgements

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Nomenclature

\( b \) = Arps decline exponent
\( D \) = Arps decline rate \( \left( T^{-1} \right) \)
\( q \) = Oil production rate \( \left( L^3 T^{-1} \right) \)
\( t \) = Production time \( (T) \)
\( t_o \) = Initial production time \( (T) \)
\( D_i \) = Initial decline constant for hyperbolic rate relation \( (T^{-1}) \)
\( \bar{p} \) = Average pressure \( (FL^2) \)
\( p_w \) = Flowing bottomhole pressure \( (FL^2) \)
\( \phi \) = Effective porosity \( (%) \)
\( c_t \) = Total reservoir compressibility \( (L^2 F^{-1}) \)
\( J \) = Productivity index \( (L^3 F^{-1} T) \)
\( \tau \) = Time constant \( (T) \)
\( V_R \) = Pore volume component \( (L^3) \)
\( L_d \) = Drainage distance \( (L) \)
\( \beta \) = Drainage distance constant
\( D_{\infty} \) = Decline constant at infinite time for power-law exponential relation \( (T^{-1}) \)
\( \hat{D}_i \) = Decline constant for power-law exponential relation \( (T^{-1}) \)
\( D_{\min} \) = Terminal decline rate \( (\% T^{-1}) \)
\( q_i \) = Initial oil production rate \( (L^3 T^{-1}) \)
\( \hat{q}_i \) = Rate intercept for power-law exponential relation \( (L^3 T^{-1}) \)
\( EUR \) = Estimated ultimate recovery \( (L^3) \)
\( n \) = Time exponent for power-law exponential relation, \( n < 1 \)

References


Figure 1 - Arps hyperbolic decline analysis is used until $D$ reaches $D_{\text{min}}$, after which the exponential decline equation with the decline exponent, $D_{\text{min}}$, is used.

Figure 2 - A typical well log of Elm Coulee field
Figure 3 - Changing $b$ - exponent in Arps hyperbolic decline rate equation

6 months: $b=2.0$, EUR= 421 MBBLS
12 months: $b=1.9$, EUR= 382 MBBLS
24 months: $b=1.1$, EUR= 317 MBBLS

Figure 4 - Power-law exponential rate decline with changing $b$ and $D$

Figure 5 - Type-curve methods to decipher well flow regimes
Figure 6 - Elm Coulee field example

Figure 7 - Elm Coulee decline rate distribution for 7 to 10 year interval

Figure 8 - Decline rate distribution: $D_{min}$ for North Dakota vertical wells and $D$ for Elm Coulee horizontal wells
Figure 9 - Schematic of the base case model for horizontal wells with transverse hydraulic fractures

Figure 10 - Rate history match

Figure 11 - Sensitivity analysis for terminal decline rate $D_{\text{min}}$
Figure 12 - Schematic of a horizontal well showing area of interference created by transverse fractures.

Figure 13 - Ultimate recovery comparison from Arps rate decline analysis and analytical model.

- Analytical Modeling
- Hyperbolic - Dmin = 6%
- Hyperbolic - Dmin = 10%