Abstract

During the past decade, there has been a continuing surge in the production of unconventional resources, accompanied with which is the great challenge and opportunities in unconventional resources research. Hydraulic fracturing technique is used to create fractures, enhance permeability and therefore economical production of the unconventional resources. The resulting fractures and their spacing (density) inside the stimulated reservoir volume (SRV) is a key factor in economical production from these very low permeability resources. It is believed that gas production enhanced by increasing fracture density resulted from hydraulic fracturing. However, there is no study about effect of fracture density on production from gas condensate unconventional resources. Eagle Ford shale is considered as one of the most important oil and gas shale plays in North America. In this study, we focused on finding the optimum fracture spacing (density) to maximize the production from the Eagle Ford gas condensate window.

In this study, we modeled a SRV in the Eagle Ford gas condensate window. Based on MICP experiment results and pore-throat size distribution of an Eagle Ford shale sample, the pore volume of the reservoir around the hydraulic fracture was divided into five regions. The physics of multiphase flow of gas and condensate were modified in order to take into account the effect of pore size on phase behavior, permeability and non-Darcy flow and therefore production from Eagle Ford gas condensate window. For each pore size, a specific permeability and PVT properties were assigned. Organic and inorganic pores with different wettability preferences were randomly distributed in the model with activated desorption mechanism in organic pores. We considered fracture spacing of 160ft, 80ft, 40ft, and 20ft inside the SRV and analyzed the effect of fracture density on production.
Results indicated that the non-Darcy flow and desorption mechanisms are absent in the early stages of production where the pressure is significantly high. However, as the reservoir depletes, slip and transition flow occurs, which results in an increase in apparent permeability and the adsorbed phase starts to desorb from the rock surface. Moreover, decreasing fracture spacing from 160 ft to 20 ft increases cumulative gas production. On the other hand, there exists an optimum fracture spacing for condensate production. Low fracture spacing (20 ft) caused more condensate dropout because of significant pressure drop. Thus, while the general belief is that higher fracture density results in higher gas production, the results of this study revealed that cumulative condensate production decreases for higher fracture densities in long-term production due mainly to the condensate drop out effect.

Selected References


Outlines

• Introduction
• Objective
• Petrophysical properties of the Eagle Ford Shale
• Synthetic reservoir model
• Confinement effect
• Non-Darcy flow and desorption effects
• Fracture density optimization
• Conclusions
Introduction

- Hydraulic fracturing technique is used to create fractures and high permeability region.
- Warpinski et al. (2008) investigated the effect of fracture density on production from shale gas reservoirs.

Warpinski et al., 2008
Do we have the same physics of fluid phase behavior and transport in unconventional?

- Deviation of fluid properties under confinement
- The mean free path of molecules is in the order of the pore radius
- Organic nano-pores store a significant portion of gas in form of sorbed
- Pore connectivity

Loucks et al. (2009)
Introduction

• Pore-wall proximity effect on phase behavior

\[ \Delta T_c = \frac{T_c - T_{cz}}{T_c} = 1.1775 \left( \frac{D}{\sigma} \right)^{-1.338} \quad \text{for} \quad \left( \frac{D}{\sigma} \right) \geq 1.5 \]

\[ \Delta T_c = \frac{T_c - T_{cz}}{T_c} = 0.6 \quad \text{for} \quad \left( \frac{D}{\sigma} \right) \leq 1.5 \]

\[ \Delta P_c = \frac{P_c - P_{cz}}{P_c} = 1.5686 \left( \frac{D}{\sigma} \right)^{-0.783} \]

Data points from Singh (2009) and correlation from Ma et al. (2013)
Introduction

- Two-phase envelope change due to confinement effects:

![Graph showing reservoir fluid composition and pressure-temperature relationships with critical points at different confinement levels.](Image)
Objective

• Optimum fracture density in the Eagle Ford gas condensate window

  ➢ Phase behavior change in nanopores

  ➢ Permeability as a function of pore size

  ➢ Effect of Non-Darcy flow and desorption
Pore throat size distribution
Mean pore size vs. permeability/porosity

From permeability, porosity, and MICP experiments on the Eagle Ford shale samples

\[ r_{pore} = 0.2829 \left( \frac{k}{\varnothing} \right) + 11.218 \]
Pore size distribution

- 5 nm, 10% vol.
- 10 nm, 39% vol.
- 15 nm, 29% vol.
- 30 nm, 12% vol.
- Pore size > 40 nm, 10% vol.
Reservoir model

- Dual-permeability model
- Eagle Ford gas condensate

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Matrix permeability</td>
<td>149 nD</td>
</tr>
<tr>
<td>Natural fracture conductivity</td>
<td>0.02 mD·ft.</td>
</tr>
<tr>
<td>Propped fracture conductivity</td>
<td>20 mD·ft.</td>
</tr>
<tr>
<td>Unpropped fracture conductivity</td>
<td>4 mD·ft.</td>
</tr>
<tr>
<td>Matrix porosity</td>
<td>9.4 %</td>
</tr>
</tbody>
</table>
Reservoir model
Pore size distribution

500*620*60 ft³
Confinement effect

Bulk state

Under confinement

Pressure distribution inside SRV

Condensate saturation inside SRV

Condensate saturation

psia
PVT and Permeability correction effect

Cumulative condensate production (STB) vs Time (years)

- No PVT and Permeability correction
- PVT correction
- PVT and Permeability correction
Effect of non-Darcy flow

- Non-Darcy flow occurs when mean free path of molecules are in order of pore radius.

\[ Kn = \frac{\lambda}{d} \]
Effect of non-Darcy flow

Methane & T=180 °F

Fathi et al. (2012) Model

\[ \frac{k_a}{k_\infty} \]

Cumulative gas production (MMSCF)

Time (years)

Pressure (psia)

30 nm
Darcy flow
15 nm
10 nm
Non-Darcy flow
5 nm
Desorption mechanism

- Gas exists in both adsorbed and free phase in shale resources
- TOC in Eagle Ford: 3-7 wt.%
- Considered TOC: 5wt.%
- Randomly distributed in the model
Desorption mechanism

- Extended Langmuir isotherm model

Ambrose et al., 2011
Desorption Modeling

Cumulative gas production (MMSCF) vs. Time (years)

Cumulative condensate production (STB) vs. Time (years)

With desorption
Without desorption
Fracture density effect

(a) Fracture spacing = 20 ft.  
(b) Fracture spacing = 40 ft.  
(c) Fracture spacing = 80 ft.

SRV = 5.54 \times 10^6 ft^3
Fracture density effect

- Fracture Spacing = 20 ft.
- Fracture Spacing = 40 ft.
- Fracture Spacing = 80 ft.
- Fracture Spacing = 160 ft.

Cumulative gas production (MMSCF)

Time (years)
Fracture density effect

Cumulative condensate production (STB) vs. Time (years)

Fracture Spacing = 20 ft.
Fracture Spacing = 40 ft.
Fracture Spacing = 80 ft.
Fracture Spacing = 160 ft.

13% increase
Fracture density effect

The graph shows the cumulative condensate production (in STB) over different periods (1 year, 5 years, 10 years, and 20 years) as a function of fracture spacing (in ft). The production decreases as the fracture spacing increases.
Condensate drop-out

Fracture spacing:
- 20 ft.
- 40 ft.
- 80 ft.
- 160 ft.

Condensate saturation (fraction) vs. Distance (ft.)

1 year
Conclusions

- Considering phase behavior modification in nanopores has a positive impact on condensate production while applying permeability distribution has a negative impact on production.

- Non-Darcy flow does not have significant impact on production at high pressures. This effect becomes quite significant for laboratory low operational pressures.

- Desorption has a negligible effect on gas and condensate production from this reservoir.

- Increasing fracture density improves cumulative gas production and short term cumulative condensate production forecasts. But, the long term cumulative condensate production decreased as the fracture density increased.
Acknowledgements / Thank You / Questions

Unconventional Shale Gas research group at University of Oklahoma
• Pore proximity effect on ethane density @ p=600 psi , T=28 °C
Pore proximity effect on methane properties

Normalized viscosity relative to bulk viscosity

Normalized Viscosity relative to bulk viscosity (fraction)

Pressure (psia)

- 10 nm
- 5 nm
- 2 nm
- 1 nm
- 50 nm

Percentage changes:
- 3%
- 6%
- 12%
- 23%
Reservoir model 1: Single porosity simulation cases

Bulk condition under confinement effect (pore size = 13 nm)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Matrix permeability</td>
<td>149 nD</td>
</tr>
<tr>
<td>Fracture conductivity</td>
<td>2 mD-ft</td>
</tr>
<tr>
<td>Fracture half length</td>
<td>250 ft.</td>
</tr>
<tr>
<td>Porosity</td>
<td>9.4 %</td>
</tr>
<tr>
<td>Initial reservoir pressure</td>
<td>5000 psi</td>
</tr>
<tr>
<td>Reservoir temperature</td>
<td>180 F</td>
</tr>
<tr>
<td>Simulation time</td>
<td>30 years</td>
</tr>
</tbody>
</table>
Effect of confinement on condensate and gas viscosity profiles

- Gas viscosity profiles for 15 years.
- Condensate viscosity profiles for 15 years, showing confined and unconfined conditions.
Effect of confinement on condensate saturation profile

![Graph showing the effect of confinement on condensate saturation profile. The graph displays two curves: one for unconfined and one for confined conditions. The x-axis represents the radius in feet (0-160 ft.), and the y-axis represents the condensate saturation fraction (0-0.3). The graph indicates that confinement reduces the condensate saturation profile, with a significant difference observed at 15 years.](image-url)
Effect of confinement on production

Cumulative gas production (MMSCF) over time (years)

- Confinement
- Unconfinement

Cumulative condensate production (STB) over time (years)

- Confinement
- Unconfinement

8% difference in gas production
35% difference in condensate production
Pore size variation and connectivity consideration

Bulk 3 µD

30 nm 620 nD

50 nD 10 nm

120 nD 15 nm
Results: different PVT regions are considered
Results: different PVT and permeability regions are considered.
Results: Effect of different parameters on Cumulative condensate production (Model 3)

- **Average permeability + No phase behavior correction**
- **Permeability change + No phase behavior correction**
- **Phase behavior correction + Average permeability**
- **Permeability change + Phase behavior correction**

- 20% increase
- 40% increase
- 5% decrease
Results: Effect of non-Darcy flow

- Model 1-ND
- Model 1
- Model 2-ND
- Model 2
- Model 3-ND
- Model 3

Cumulative gas production (MMSCF) vs. Time (years)
two-phase envelope change
Due to Pore proximity

<table>
<thead>
<tr>
<th>Group #</th>
<th>Component</th>
<th>% mole</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>CH4</td>
<td>80</td>
</tr>
<tr>
<td>2</td>
<td>NC4</td>
<td>10</td>
</tr>
<tr>
<td>3</td>
<td>FC8</td>
<td>10</td>
</tr>
<tr>
<td>Sum</td>
<td></td>
<td>100</td>
</tr>
</tbody>
</table>

Pressure (psia) vs. Temperature (F) graph with critical points and reservoir pressure path.
Non-Darcy flow occurs when mean free path of molecules are in order of pore radius.

Ziarani and Aguilera (2012)
Introduction

- Knudsen number is a measure of degree of rarefaction
  \[ K_n = \frac{\lambda}{d} \]
  - Smaller pores or lower pressure the higher the Kn
  - The higher the Knudsen number the more deviation from Darcy flow
# Introduction

- **Flow regimes**

<table>
<thead>
<tr>
<th>Flow Equation</th>
<th>Flow Regimes</th>
<th>Knudsen Number Limits</th>
</tr>
</thead>
<tbody>
<tr>
<td>Darcy</td>
<td>Continuum flow</td>
<td>$Kn &lt; 0.001$</td>
</tr>
<tr>
<td>Non-Darcy</td>
<td>Slip flow</td>
<td>$0.001 &lt; Kn &lt; 0.1$</td>
</tr>
<tr>
<td></td>
<td>Transition flow</td>
<td>$0.1 &lt; Kn &lt; 10$</td>
</tr>
<tr>
<td></td>
<td>Free molecular flow</td>
<td>$Kn \geq 10$</td>
</tr>
</tbody>
</table>

Schaaf and Chambre (1961)

Tight and shale gas reservoir
Velocity profile in small capillaries

- Smaller pore size
- Transition flow
- Slip flow

Fathi et al. (2012)
Introduction

- Flow regimes in tight and shale gas reservoirs

Xiao and Wei (1990)
Permeability correction

- **Klinkenberg correction**
  \[ k_a = k_\infty \left( 1 + \frac{b_k}{P} \right) \]
  Valid for slip flow

- **Knudsen correction**
  \[ k_a = k_\infty \left( 1 + \frac{A}{P} + \frac{B}{P^2} \right) \]
  Valid for slip and transition flow regimes
First-order equations (Klinkenberg correction)

- Klinkenberg (1941), first introduced the effect of gas slippage effect on Apparent permeability of gas

\[ k_a = k_\infty \left( 1 + \frac{b_k}{\bar{P}} \right) \]

- Slippage factor

\[ \frac{b_k}{\bar{P}} = \frac{4c\lambda}{r} \]
### First-order equations (Klinkenberg)

Various correlations for Klinkenberg’s gas slippage factor \( b_k \)

<table>
<thead>
<tr>
<th>Model</th>
<th>Correlation</th>
<th>Comments/units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Klinkenberg (1941)</td>
<td>( b_k = 4c\lambda \bar{P} / r )</td>
<td>( c ) is a constant close to unity</td>
</tr>
<tr>
<td>Heid et al. (1950)</td>
<td>( b_k = 11.419(k_\infty)^{-0.39} )</td>
<td></td>
</tr>
<tr>
<td>Jones and Owens (1979)</td>
<td>( b_k = 12.639(k_\infty)^{-0.33} )</td>
<td></td>
</tr>
<tr>
<td></td>
<td>( b_k = 13.851(k_\infty / \phi)^{-0.53} )</td>
<td></td>
</tr>
<tr>
<td>Sampath and Keighin (1982)</td>
<td>( b_k = \beta (k_\infty / \phi)^{-0.5} )</td>
<td>Gas ( \beta )-Value</td>
</tr>
<tr>
<td>Florence et al. (2007)</td>
<td>( b_k = \beta (k_\infty / \phi)^{-0.5} )</td>
<td>Nitrogen 43.345</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Air 44.106</td>
</tr>
<tr>
<td>Civan (2010)</td>
<td>( b_k = 0.0094 (k_\infty / \phi)^{-0.5} )</td>
<td>Correlation for Nitrogen. Units: ( b_k ) (Pa), ( k_\infty ) (m(^2))</td>
</tr>
</tbody>
</table>

Units: \( b_k \) (psi), \( k_\infty \) (md), \( \bar{P} \) (psi), \( r \) (nm), \( \beta \) (psi), \( \lambda \) (nm) and \( \phi \) (fraction)

Ziarani and Aguilera (2012)
<table>
<thead>
<tr>
<th>Model</th>
<th>Correlation</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Beskok and Karniadakis (1999)</td>
<td>$k_a = k_\infty \left[ 1 + \alpha(Kn) Kn \right] \left[ 1 + \frac{4Kn}{1 + Kn} \right]$</td>
<td>$\alpha$ is rarefaction coefficient and is a function of Knudsen number</td>
</tr>
<tr>
<td></td>
<td>$\alpha(Kn) = \frac{128}{15\pi^2} \tan^{-1} \left[ 4Kn^{0.4} \right]$</td>
<td></td>
</tr>
<tr>
<td>Civan (2010)</td>
<td>$k_a = k_\infty \left[ 1 + \alpha(Kn) Kn \right] \left[ 1 + \frac{4Kn}{1 + Kn} \right]$</td>
<td>Inverse power-law expression for rarefaction factor</td>
</tr>
<tr>
<td></td>
<td>$\alpha(Kn) = \frac{\alpha_0}{1 + \frac{A}{Kn^B}}$</td>
<td></td>
</tr>
<tr>
<td>Sakhaee-pour and Bryant (2012)</td>
<td>$k_a = k_\infty \left( 0.8453 + 5.4576Kn + 0.1633Kn^2 \right)$</td>
<td>$0.1 &lt; Kn &lt; 0.8$</td>
</tr>
<tr>
<td>Javadpour (2009)</td>
<td>$k_a = \frac{D_k \mu M}{RT \rho} + Fk_\infty$</td>
<td></td>
</tr>
<tr>
<td></td>
<td>$F = 1 + \left( \frac{8\pi RT}{M} \right)^{0.5} \frac{\mu}{\bar{P}r} \left( \frac{2}{\alpha} - 1 \right)$</td>
<td></td>
</tr>
<tr>
<td>Fathi (2012)</td>
<td>$k_a = k_\infty \left[ 1 + \left( \frac{b}{\bar{P}} \right)^2 \left( \frac{L_{kE}}{\lambda} \right) \right]$</td>
<td>Double-slip theory</td>
</tr>
<tr>
<td>Bravo (2007)</td>
<td>$b = f(P)$</td>
<td>Three velocity profiles</td>
</tr>
</tbody>
</table>
Which flow regime?

Knudsen number vs. pressure (T=100 F, pore size=10 nm)

Transition flow region

Slip flow region

continuum flow region
Fig. 1 - Pore size scales for different effects occurring in natural reservoirs.
Adsorption model

- Extended Langmuir (EL) model

\[
G = \frac{V_L P}{P + P_L} \\
G_{Li} = \frac{V_{L,i} (P_i/P_{Li})}{1 + \sum_j (P_j/P_{Lj})}
\]
Relative permeability

Sw

Krw

Kro

Sl

Krog

Krg
Effect of confinement on components mole fraction

Methane

Intermediate components

Heavy components
Cumulative gas production (MMSCF) vs. Time (years)

- Model 1
- Model 2
- Model 3
- Model 4