Reservoir Fluid Properties Required for Low-Permeability Oil Reservoir Analysis*

Matt Mavor\(^1\)

Search and Discovery Article #80363 (2014)**
Posted March 10, 2014

*Adapted from oral presentation given at Geoscience Technology Workshop, Hydrocarbon Charge Considerations in Liquid-Rich Unconventional Petroleum Systems, Vancouver, BC, Canada, November 5, 2013

**AAPG©2013 Serial rights given by author. For all other rights contact author directly.

\(^1\)Senior Technical Advisor, Apache Corporation (Matt.Mavor@apachecorp.com)

Abstract

Quantifying fluid flow through porous media requires accurate fluid property estimates. This is especially important for low-permeability oil reservoirs which will produce gas, oil, and water in time-dependent proportions due to hydraulic fracture stimulation and production pressures below oil bubble-point pressure. Gas and oil properties are required to properly quantify flowing properties, such as the effective permeability to each phase, to determine the oil and gas volumes in-place, to predict future production rates and recovery, and to evaluate open-hole log data.

Reservoir fluid systems are classified based upon the phase behavior relative to the critical point of a multicomponent hydrocarbon mixture. The fluid-system phase behavior PVT (pressure-volume-temperature) analysis depends on the fluid type. Representative fluid samples are required for the analysis. These samples are best acquired by recombining separator oil and gas samples collected under relatively stable production conditions very early in the life of a reservoir. The samples are recombined at the separator gas-oil rate ratio to serve as the reservoir fluid sample.

Oil production behavior is strongly dependent upon the oil gravity and the original solution gas-oil ratio. The differences in behavior for three actual Permian oil reservoirs are demonstrated with reservoir simulation models. An example PVT analysis of one of the fluid systems is discussed.

References Cited


RESERVOIR FLUID PROPERTIES REQUIRED FOR LOW-PERMEABILITY OIL RESERVOIR ANALYSIS

Matt Mavor
Apache Corporation
Nov. 4, 2013
Reservoir Fluid Property Importance

- Fluid flow through porous media requires accurate fluid phase behavior data
- Especially important under multiphase flow conditions
- Fluid-in-place volumes
- Future production and recovery forecasts
- Reservoir flow properties (permeability to fluids, etc.)
Properties for In-Place and Recovery Estimates

- Phase pressure and temperature boundaries
- Density & formation volume factor
- Vapor & liquid solubility
- Compressibility
- Viscosity
Outline

- Classification of reservoir fluid systems
- Basic phase behavior concepts
- Fluid sampling and rate measurement
- Effect of solution gas-oil ratio upon well performance
- PVT study black oil properties
- Possible modifications for tight oil reservoirs
Classification of Reservoir Fluid Systems

- Reservoir Fluid Types
  1. Dry Gas
  2. Wet Gas
  3. Gas Condensate
  4. Volatile Oil
  5. Black Oil

- Classification based upon:
  - Reservoir temperature relative to the critical point and cricondentherm
  - Properties at the 1st stage separator temperature and pressure relative to the fluid phase diagram
Single Molecular Species p-T Diagram

Reference: Whitson & Brule
Phase Behavior
SPE Monograph
Series Vol. 20
p. 9

Fig. 2.4—p-T diagram for a single component in the region of vapor/liquid behavior near the critical point (\( p_c \) = critical pressure and \( T_c \) = critical temperature).
Multicomponent p-T Phase Diagram

Reference: Whitson & Brule
Phase Behavior
SPE Monograph Series Vol. 20
p. 15
# Example Reservoir Fluid Compositions

<table>
<thead>
<tr>
<th>Component</th>
<th>Dry Gas</th>
<th>Wet Gas</th>
<th>Condensate</th>
<th>Near-Critical Oil</th>
<th>Volatile Oil</th>
<th>Black Oil</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO₂</td>
<td>0.10</td>
<td>1.41</td>
<td>2.37</td>
<td>1.30</td>
<td>0.93</td>
<td>0.02</td>
</tr>
<tr>
<td>N₂</td>
<td>2.07</td>
<td>0.25</td>
<td>0.31</td>
<td>0.56</td>
<td>0.21</td>
<td>0.34</td>
</tr>
<tr>
<td>C₁</td>
<td>86.12</td>
<td>92.46</td>
<td>73.19</td>
<td>69.44</td>
<td>58.77</td>
<td>34.62</td>
</tr>
<tr>
<td>C₂</td>
<td>5.91</td>
<td>3.18</td>
<td>7.80</td>
<td>7.88</td>
<td>7.57</td>
<td>4.11</td>
</tr>
<tr>
<td>C₃</td>
<td>3.58</td>
<td>1.01</td>
<td>3.55</td>
<td>4.26</td>
<td>4.09</td>
<td>1.01</td>
</tr>
<tr>
<td>i-C₄</td>
<td>1.72</td>
<td>0.28</td>
<td>0.71</td>
<td>0.89</td>
<td>0.91</td>
<td>0.76</td>
</tr>
<tr>
<td>n-C₄</td>
<td>0.24</td>
<td>1.45</td>
<td>2.14</td>
<td>2.09</td>
<td>0.49</td>
<td></td>
</tr>
<tr>
<td>i-C₅</td>
<td>0.50</td>
<td>0.13</td>
<td>0.64</td>
<td>0.90</td>
<td>0.77</td>
<td>0.43</td>
</tr>
<tr>
<td>n-C₅</td>
<td>0.08</td>
<td>0.68</td>
<td>1.13</td>
<td>1.15</td>
<td>0.21</td>
<td></td>
</tr>
<tr>
<td>C₆(s)</td>
<td>0.14</td>
<td>1.09</td>
<td>1.46</td>
<td>1.75</td>
<td>1.61</td>
<td></td>
</tr>
<tr>
<td>C₇+</td>
<td>0.82</td>
<td>8.21</td>
<td>10.04</td>
<td>21.76</td>
<td>56.40</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Properties</th>
<th>M&lt;sub&gt;C₇+&lt;/sub&gt;</th>
<th>γ&lt;sub&gt;C₇+&lt;/sub&gt;</th>
<th>K&lt;sub&gt;W₇&lt;/sub&gt;</th>
<th>GOR, scf/STB</th>
<th>OGR, STB/MMscf</th>
<th>γ&lt;sub&gt;API&lt;/sub&gt;</th>
<th>γ&lt;sub&gt;g&lt;/sub&gt;</th>
<th>ρ&lt;sub&gt;sat&lt;/sub&gt;, psia</th>
<th>B&lt;sub&gt;sat&lt;/sub&gt;, ft³/scf or bbl/STB</th>
<th>ρ&lt;sub&gt;sat&lt;/sub&gt;, lbm/ft³</th>
</tr>
</thead>
</table>
Reservoir Fluid Classification

Vapor Reservoirs
Dry Gas
Wet Gas
Gas Condensate
Liquid Reservoirs
Separator Liquid Gravity API
Volatile Oil
Wet Gas
Gas Condensate

Vapor-liquid ratio guidelines are only valid during single phase production above the bubble point or dew point. (early in reservoir production history)

Vapor-Liquid Ratio Guidelines

<table>
<thead>
<tr>
<th>Gas-Oil Ratio scf/STB</th>
<th>100,000</th>
<th>10,000</th>
<th>1,000</th>
<th>100</th>
<th>10</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil-Gas Ratio STB/MMscf</td>
<td>10</td>
<td>100</td>
<td>1,000</td>
<td>10,000</td>
<td>100,000</td>
</tr>
</tbody>
</table>
PVT Studies Require Reservoir Fluid Samples

PVT: Pressure-Volume-Temperature

- Recombined Separator Oil & Gas Samples
  - Accurate gas, oil, and water flow rates required
  - Gas-oil ratio must be relatively stable
  - Gas & oil samples are recombined by the PVT lab

- Downhole Samplers
  - *Should not be used for low-perm reservoirs*
  - Reliable only for single phase flow above bubble point or dew point pressure
  - Compromised by water production
Gas rates are commonly measured with gas orifice meters.

Oil and water rates are commonly measured with turbine flow meters and stock tank straps (liquid level in the tank).
Permian Tight Oil Well GOR During Sampling

Separator oil meters not used. Lab oil flash shrinkage measurements were required. Separator oil shrinkage factor: 0.916

Recombination Gas-Oil Ratio
546 scf of separator vapor per barrel of separator oil

PVT Sample
Average GOR 596 scf/STB
Presenter’s notes: Three Wolfcamp PVT studies have been completed on recombined separator gas and oil samples. There has been a minor variation in oil gravity with a substantial variation in solution gas-oil ratios which affects reservoir fluid properties, in particular the bubble point pressure. The reservoir fluid classification is volatile oil based upon the oil gravity and gas-oil ranges. In each case, the reservoirs are under-saturated with bubble point pressures less than the initial reservoir pressure. The degree of saturation (bubble point pressure / reservoir pressure) increases with the increase in oil gravity and solution gas-oil ratio for these three samples.
Simulation of One Stage of a Tight Oil Frac

23 Total Stages
4 perf clusters & induced fracs per stage
Induced frac length 350 feet

Matrix permeability to oil: 0.001 md
Matrix block spacing: 10 feet
Induced frac perm: 4 md
Induced frac cond. 20 md-ft

Stage Drainage Area 3.8 acres
Collect PVT samples and characterize fluid properties early.
Long Term Oil Rate and Produced GOR

Oil Rate, Bubble Point GOR 666 scf/STB
Oil Rate, Bubble Point GOR 963 scf/STB
Oil Rate, Bubble Point GOR 1,230 scf/STB
Gas-Oil Ratio, Bubble Point GOR 667 scf/STB
Gas-Oil Ratio, Bubble Point GOR 963 scf/STB
Gas-Oil Ratio, Bubble Point GOR 1,230 scf/STB

10,164 scf/STB
8,650 scf/STB
4,726 scf/STB
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>6,015</td>
<td>0.7385</td>
<td>1.3151</td>
<td>666.6</td>
<td>666.6</td>
<td>9.45E-06</td>
<td>0.708</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5,515</td>
<td>0.7351</td>
<td>1.3212</td>
<td>666.6</td>
<td>666.6</td>
<td>9.87E-06</td>
<td>0.689</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5,015</td>
<td>0.7316</td>
<td>1.3276</td>
<td>666.6</td>
<td>666.6</td>
<td>1.04E-05</td>
<td>0.662</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>4,515</td>
<td>0.7279</td>
<td>1.3343</td>
<td>666.6</td>
<td>666.6</td>
<td>1.10E-05</td>
<td>0.650</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>4,015</td>
<td>0.7240</td>
<td>1.3414</td>
<td>666.6</td>
<td>666.6</td>
<td>1.18E-05</td>
<td>0.637</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3,450</td>
<td>0.7194</td>
<td>1.3500</td>
<td>666.6</td>
<td>666.6</td>
<td>1.27E-05</td>
<td>0.627</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3,015</td>
<td>0.7156</td>
<td>1.3572</td>
<td>666.6</td>
<td>666.6</td>
<td>1.39E-05</td>
<td>0.619</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2,515</td>
<td>0.7109</td>
<td>1.3662</td>
<td>666.6</td>
<td>666.6</td>
<td>1.44E-05</td>
<td>0.616</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2,315</td>
<td>0.7089</td>
<td>1.3700</td>
<td>666.6</td>
<td>666.6</td>
<td>1.58E-05</td>
<td>0.614</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1,965</td>
<td>0.7052</td>
<td>1.3773</td>
<td>666.6</td>
<td>666.6</td>
<td>0.685</td>
<td>0.8035</td>
<td>0.8035</td>
<td>0.820</td>
<td>0.0088</td>
<td>113.901</td>
<td>0.0167</td>
<td>41.02</td>
</tr>
<tr>
<td>1,615</td>
<td>0.7136</td>
<td>1.3291</td>
<td>536.6</td>
<td>666.6</td>
<td>0.774</td>
<td>0.8053</td>
<td>0.8035</td>
<td>0.838</td>
<td>0.0110</td>
<td>90.751</td>
<td>0.0156</td>
<td>49.62</td>
</tr>
<tr>
<td>1,315</td>
<td>0.7218</td>
<td>1.2907</td>
<td>440.4</td>
<td>666.6</td>
<td>0.883</td>
<td>0.8131</td>
<td>0.8068</td>
<td>0.860</td>
<td>0.0147</td>
<td>68.255</td>
<td>0.0145</td>
<td>60.90</td>
</tr>
<tr>
<td>1,015</td>
<td>0.7304</td>
<td>1.2535</td>
<td>349.8</td>
<td>666.6</td>
<td>1.023</td>
<td>0.8486</td>
<td>0.8166</td>
<td>0.885</td>
<td>0.0214</td>
<td>46.723</td>
<td>0.0136</td>
<td>75.22</td>
</tr>
<tr>
<td>715</td>
<td>0.7401</td>
<td>1.2129</td>
<td>253.2</td>
<td>666.6</td>
<td>1.174</td>
<td>0.9296</td>
<td>0.8393</td>
<td>0.917</td>
<td>0.0382</td>
<td>26.173</td>
<td>0.0128</td>
<td>91.72</td>
</tr>
<tr>
<td>415</td>
<td>0.7519</td>
<td>1.1659</td>
<td>149.5</td>
<td>666.6</td>
<td>1.460</td>
<td>1.2011</td>
<td>0.9213</td>
<td>0.964</td>
<td>0.1449</td>
<td>6.899</td>
<td>0.0119</td>
<td>122.69</td>
</tr>
<tr>
<td>115</td>
<td>0.7750</td>
<td>1.0799</td>
<td>0.0</td>
<td>666.6</td>
<td>2.074</td>
<td>1.5634</td>
<td>1.0349</td>
<td>0.998</td>
<td>1.1505</td>
<td>0.869</td>
<td>0.0113</td>
<td>183.54</td>
</tr>
<tr>
<td>15</td>
<td>0.8068</td>
<td>0.9768</td>
<td>0.0</td>
<td>666.6</td>
<td>2.074</td>
<td>1.5634</td>
<td>1.0349</td>
<td>0.998</td>
<td>1.1505</td>
<td>0.869</td>
<td>0.0113</td>
<td>183.54</td>
</tr>
</tbody>
</table>

**Green** properties at approximate reservoir pressure

**Red** saturation pressure at 150 Deg. F.

1. barrels of oil at indicated pressure and 150 Deg. F. per barrel of stock tank oil at standard conditions
2. volume of gas at standard conditions in solution per barrel of stock tank oil at standard conditions
3. gravity of gas released by pressure decrease from previous pressure level
4. gas gravity of all gas released by pressure decrease from saturation pressure
5. volume of gas at 150 Deg. F. and indicated pressure divided by volume of gas at standard conditions
6. volume of gas at standard conditions divided by volume of gas at indicated pressure and 150 Deg. F.

standard conditions: 60 Deg. F. and 14.7 psia
separator conditions: 97 Deg. F and 134 psia
oil gravity: 38.12 Deg. API at 14.7 psia and 60 Deg. F
separator gas gravity: 0.799 relative to air
Oil Formation Vol. Factor and Solution Gas

Solution Gas-Oil Ratio
- Linear with Pressure Below Bubble Point Pressure
- Constant Above Bubble Point

Pressure Compresses Oil Above Bubble Point Pressure

Gas Swells Oil Below Bubble Point Pressure

Solution Gas-Oil Ratio

\[ B_o = \frac{\text{reservoir volume}}{\text{standard condition volume}} = \frac{\text{standard condition density}}{\text{reservoir density}} \]

Oil Compressibility

\[ c_o = -\frac{1}{B_o} \frac{\partial B_o}{\partial p} \]

Bubble Point Pressure: 1,965 psia
Reservoir Pressure: 3,450 psia

Formation Volume Factor

Solution Gas Oil Ratio
Oil Density and Viscosity

- **Gas Lowers Density Below Bubble Point Pressure**
- **Pressure Compresses Oil Above Bubble Point Pressure**
- **Gas Lowers Viscosity Below Bubble Point Pressure**
- **Pressure Increases Viscosity Above Bubble Point Pressure**

**Reservoir Pressure**: 3,450 psia

**Bubble Point Pressure**: 1,965 psia

**Oil Compressibility**

\[ c_o = \frac{1}{\rho_o} \frac{\partial \rho_o}{\partial p} \]
Gas Viscosity vs. Oil Viscosity

Below Bubble Point Pressure
Pore sizes smaller than 100 nm can cause bubble-point pressure suppression and dew-point pressure suppression or elevation.

Deviations from measured PVT data become greater as pore size decreases.

Pore size distribution becomes important.

Mathematically accounted for by:

- including capillary pressure in equation of state computations, i.e., vapor and liquid pressures differ by capillary pressure (function of pore radius, interfacial tension, and wetting angle).
- shifting critical pressure and temperature conditions.
Pore Size Ranges Published in SPE 166306

- **Macropores (unconfined)**
  - 80-87% of pore space
  - Average radius > 100 nm

- **Mesopores (mid confined)**
  - 10-15% of pore space
  - Average radius about 25 nm

- **Nanopores (confined)**
  - 3-5% of pore space
  - Average radius 2-3 nm

Black Oil System Unconfined Properties

- Bubble Point Pressure: 2,260 psia
- Bubble Point Gas-Oil Ratio: 500 scf/STB
- Stock Tank Oil Gravity: 37.7 API

Phase Envelope for Each Pore Size Class
Reservoir Area: 9.2 acres
Stimulated Rock Area: 2.8 acres
Net Thickness: 120 feet
Initial Pressure: 4,500 psia
Initial Temperature: 250 feet

Induced Fracture Spacing: 50 feet
Induced Fracture Length: 300 feet tip to tip
Induced Fracture Perm: 5 md

Dual Permeability Reservoir Model
Matrix Porosity: 5%
Matrix Abs. Perm.: $10^{-4}$ md
Secondary System Block Size: 50 by 50 feet