Reservoir Characterization Problems Requiring Core-Scale Characterization Solutions: Sometimes You Just Have to Know What Is Happening Every Foot*

By
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Abstract

Different reservoir systems are examined illustrating situations where critical reservoir properties must be evaluated at the one-foot scale (0.3 m) to understand and model reservoir performance. Systems requiring fine-scale properties include the Cretaceous Niobrara Chalk; Pennsylvanian oomoldic limestones; Silurian, Mississippian and Permian carbonates interpreted to be tidal flat to intertidal deposits; and Cretaceous low-permeability sandstones. In all these systems porosity, permeability, capillary pressure, and relative permeability exhibit high frequency vertical variability requiring discrete analysis for accurate formation evaluation. With fine-scale properties for a location it is possible to upscale each property at that location, however, upscaling of properties generally “decouples” petrophysical relations defined at finer scales (e.g., core scale). Upscaled property relationships can also exhibit unacceptably wide variance because of the non-unique solution an upscaled property represents relative to the comprised fine-scale properties. Defining the representative elementary volume scale common to all properties requires testing the scale-dependence of the complete process not just by changing cell dimensions but also scaling reservoir properties. Obtaining a model solution for one process does not guarantee the model will be suitable for another process. Further, population of a coarse-scale geomodel is complicated by the non-unique solution for how one or more upscaled properties relate to other properties. These fine-scale reservoir models lend insight into the complications of heterogeneous lithologies at differing spatial scales and underscore the difficulty of upscaling properties for reservoir simulation. Analysis also indicates that for some architectures capillary pressure and relative permeability anisotropy may need to be considered.

References


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Alan P. Byrnes
Now with Chesapeake Energy

AAPG April, 2008
Overview

• Upscaling is at heart of nearly all characterization
• Examine four examples of upscaling issues where core-scale solutions were required for accurate characterization
  – Permian thin-bedded carbonate; k upscaling
  – Cretaceous tight gas sandstone; influence of single thin bed
  – Cretaceous Niobrara chalk; coupled density-saturation-k-kr
  – Penn/Miss moldic carbonate; kr upscaling, emergent property limitations on upscaling
• Key Learnings
  – Sometimes upscaling is permitted but must start at fine-scale and uncouple petrophysical relationships (e.g., k-φ k-Pc)
  – Sometimes the entire story is at the one-foot scale
  – Sometimes properties may be upscaled but emergent property (flow during production) creates conditions for which upscaling for one condition was not correct for new condition
Upscaling Porosity

- Porosity is dimensionless and scalar
- Upscaling is simple average at common scale
- Log or core data can be averaged based on weighted thickness or volume

$$\phi_{\text{average}} = \frac{\sum_{i=1}^{i=n} \phi_i \cdot V_i}{\sum_{i=1}^{i=n} V_i}$$
Upscaling Permeability

- Permeability is a vector/tensor
- Pseudo-Permeability is flow model dependent
- Permeability is frequently scale dependent depending on architectural changes with scale

Series Flow

Parallel Flow

No vertical cross-flow
Vertical crossflow $k_v = 0$, $k_v = C k_h$

Heterogeneous Flow
Relative Permeability Upscaling

- Two principal approaches

End-point scaling

average
Model of Measured vs Composite Permeability for Layered Samples

Permeability-Porosity Equation: \( k = 3.65 \times 10^{-5} e^{(0.68 \phi)} \)

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<th>Upper Layer Porosity (%)</th>
<th>Base Layer Porosity (%)</th>
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<th>Base Layer K (md)</th>
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- Difference is simple mathematic consequence of averaging linear porosity and logarithmic permeability
Parallel Beds and Sampling

- when sample contains parallel beds of different $k$ and $k = a\phi^b$ of $k = ae^{b\phi}$
  - the observed $k$ at the average porosity is always greater than the calculated $k$ for the average porosity
  - porosity is linearly averaged and permeability is average of log-transformed values
Permian Hugoton – Permeability Upscaling

Permian limestone assume uniform lithology Packstone/Pack-Grainstone

Byrnes, 4/08
Cretaceous Mesaverde Tight Gas Sandstones

[Map of the region showing the locations of Green River, Wind River, Washakie, Piceance, Powder River, Wyoming, Utah, and Colorado.]
CMG IMEX
Single 1-ft thick High-Permeability Layered Reservoir Simulation Model

- 1ft – 0.01, 0.1, 1, 10, 100 md
- $k_{eg} = 0.004, 0.04, 0.4, 4, 40$ md
- $S_{wc} = 0.34, k_{rg} = 0.38$
- $k_{base} = 0.004$ md, $k_{vert} = 0.0004$ md
Base Model – $k_{eg}=0.004$ md

![Graph showing pressure and cumulative gas over time](image)
$k_{\text{high}} = 4 \text{ md, } k_{\text{base}} = 0.004 \text{ md}$
Setting Of Niobrara Shallow Gas Play

In situ Porosity (%)

Approx. In situ Klinkenberg Permeability (md)

$kk = 1.11 \times 10^{-9} \phi^{0.47}$
$R^2 = 0.81$

$k_k = 1.55 \times 10^{-12} \phi^{17/5}$
$R^2 = 0.81$

Lockridge and Pollastro (1988)
Sherman Co., KS

m=1.88, a=1
n=2.15
Sherman Co., KS

Log-calculated $k_{egh} = 24 \text{ md-ft}$
Well test analysis $k_{egh} = 28 \text{ md-ft}$
Pennsylvanian Lansing-Kansas City Oomoldic Limestone & Mississippian Moldic Carbonate

\[ Sw = f(K, H) \]

\[ K_{row} = f(K) \]

(after Byrnes & Bhattacharya, 2006; SPE 99736)
Residual Oil vs C and $S_{oi}$

**Lansing-Kansas City**

**Mississippian**

Byrnes, 4/08
Kr Family

\[ kr = f(k_{abs}) \]

\[ kr = C \]

\[ kr = f(k_{abs}, S_{oi}) \]
Upscaled System Response

\[ k_{rg} = \left( \frac{S_w - S_{wc}}{1 - S_{gc} - S_{wc}} \right)^{Nw} \left( 1 - \frac{S_w - S_{wc}}{1 - S_{wc}} \right)^2 \]

\[ k_{rw} = \left( \frac{S_w - S_{wc}}{1 - S_{wc}} \right)^{Nw} \]

- Identical kro, krw
- Only water influx changes
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"Yes, they're all fools, gentlemen. . . .
But the question remains, 'What kind of fools are they?' "
Are we alone in this issue?

Idealized portrayal of how the grid size of the GCMs is too large to accommodate the real sub-grid scale vertical motion. GCMs can’t resolve (top) the concentrated rain or the surrounding cloud downdrafts and subsidence within the scale of its grid space (bottom). The top and bottom diagrams contrast the mean vertical motion of the GCM (top) and the real up-and-down vertical motion of nature. Note that the unresolved vertical motion of the top diagram allows less OLR to escape to space.

(Gray, 2006)