

RESERVOIR ENGINEERING FOR GEOLOGISTS

Part 3 – Volumetric Estimation

by Lisa Dean, Fekete Associates Inc.

You have been asked to:

- Evaluate the properties that are for sale in a data room.
- Determine whether to participate in a prospect.
- Calculate the potential reserves encountered by a discovery well.
- Identify the upside potential in a mature field.

In all these situations, the bottom line is “how much oil or gas exists and can be produced, and what will be the return on investment?” This article addresses this question.

Volumetric estimation is the only means available to assess hydrocarbons in place prior to acquiring sufficient pressure and production information to apply material balance techniques. Recoverable hydrocarbons are estimated from the in-place estimates and a recovery factor that is estimated from analogue pool performance and/or simulation studies.

Therefore, volumetric methods are primarily used to evaluate the in-place hydrocarbons in new, non-producing wells and pools and new petroleum basins. But even after pressure and production data exists, volumetric estimates provide a valuable check on the estimates derived from material balance and decline analysis methods (to be discussed in upcoming *Reservoir* issues).

VOLUMETRIC ESTIMATION

Volumetric estimation is also known as the “geologist’s method” as it is based on cores, analysis of wireline logs, and geological maps. Knowledge of the depositional environment, the structural complexities, the trapping mechanism, and any fluid interaction is required to:

- Estimate the volume of subsurface rock that contains hydrocarbons. The volume is calculated from the thickness of the rock containing oil or gas and the areal extent of the accumulation (Figure 1).
- Determine a weighted average effective porosity (See Figure 2).
- Obtain a reasonable water resistivity value and calculate water saturation.

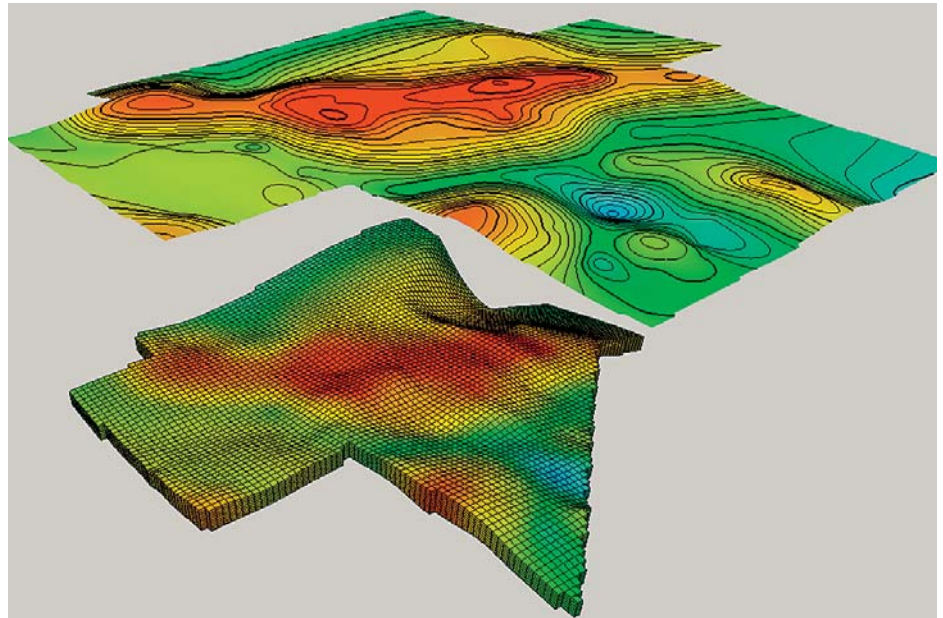


Figure 1. Areal Extent of Rock Volume Accumulation.

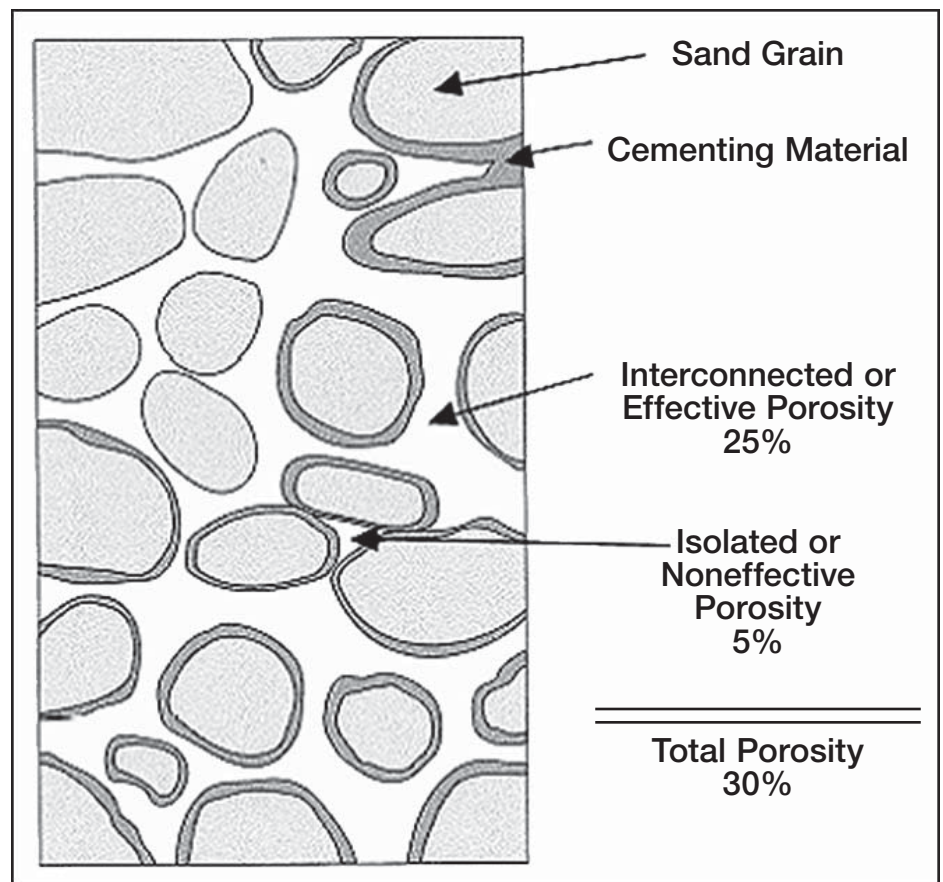


Figure 2. Weighted Average Effective Porosity.

With these reservoir rock properties and

original oil-in-place or original gas-in-place volumes can be calculated.

For **OIL RESERVOIRS** the original oil-in-place (OOIP) volumetric calculation is:

Metric:

OOIP (m³) =

Rock Volume * Φ * (1 - S_w) * I/B_o

Where: Rock Volume (m³) = 10⁴ * A * h

A = Drainage area, hectares
(1 ha = 10⁴m²)

h = Net pay thickness, metres

Φ = Porosity, fraction of rock volume available to store fluids

S_w = Volume fraction of porosity filled with interstitial water

B_o = Formation volume factor (m³/m³)
(dimensionless factor for the change in oil volume between reservoir conditions and standard conditions at surface)

I/B_o = Shrinkage (Stock Tank m³/reservoir m³)
= volume change that the oil undergoes when brought to the earth's surface due to solution gas evolving out of the oil.

Imperial:

OOIP (STB) =

Rock Volume * 7,758 * Φ * (1 - S_w) * I/B_o

Where: Rock Volume (acre feet) = A * h

A = Drainage area, acres

h = Net pay thickness, feet

7,758 = API Bbl per acre-feet (converts acre-feet to stock tank barrels)

Φ = Porosity, fraction of rock volume available to store fluids

S_w = Volume fraction of porosity filled with interstitial water

B_o = Formation volume factor
(Reservoir Bbl/STB)

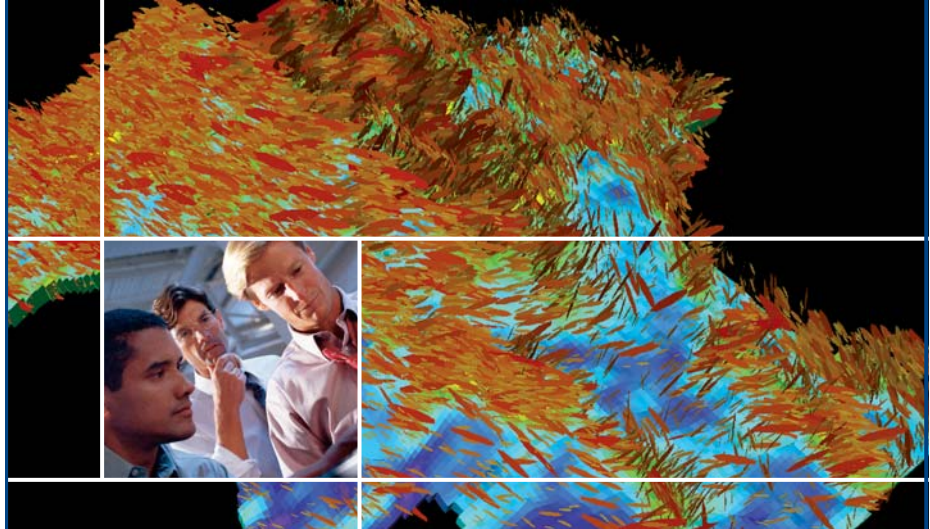
I/B_o = Shrinkage (STB/reservoir Bbl)

To calculate **recoverable oil volumes** the OOIP must be multiplied by the Recovery Factor (fraction). The recovery factor is one of the most important, yet the most difficult variable to estimate. Fluid properties such as formation volume factor, viscosity, density, and solution gas/oil ratio all influence the recovery factor. In addition, it is also a function of the reservoir drive mechanism and the interaction between reservoir rock and the fluids in the reservoir. Some industry standard oil recovery factor ranges for various natural drive mechanisms are listed below:

Solution gas drive	2 – 30%
Gas cap drive	30 – 60%
Water drive	2 – 50%
Gravity	Up to 60%

(Continued on page 22...)

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For **GAS RESERVOIRS** the original gas-in-place (OGIP) volumetric calculation is:

Metric:

OGIP (10³m³) =

$$\text{Rock Volume} * \Phi * (1-S_w) * \frac{(T_s * P_i)}{(P_s * T_f * Z_i)}$$

Where: Rock Volume (m³) = 10⁴ * A * h

A = Drainage area, hectares
(1 ha = 10⁴m²)

h = Net pay thickness, metres

Φ = Porosity, fraction of rock volume available to store fluids

S_w = Volume fraction of porosity filled with interstitial water

T_s = Base temperature, standard conditions, °Kelvin (273° + 15°C)

P_s = Base pressure, standard conditions, (101.35 kPaa)

T_f = Formation temperature, °Kelvin (273° + °C at formation depth)

P_i = Initial Reservoir pressure, kPaa

Z_i = Compressibility at P_i and T_f

Imperial:

OGIP (MMCF) =

$$\text{Rock Volume} * 43,560 * \Phi * (1-S_w) * \frac{(T_s * P_i)}{(P_s * T_f * Z_i)}$$

Where: Rock Volume (acre feet) = A * h

A = Drainage area, acres
(1 acre = 43,560 sq. ft)

h = Net pay thickness, feet

Φ = Porosity, fraction of rock volume available to store fluids

S_w = Volume fraction of porosity filled with interstitial water

T_s = Base temperature, standard conditions, °Rankine (460° + 60°F)

P_s = Base pressure, standard conditions, 14.65 psia

T_f = Formation temperature, °Rankine (460° + °F at formation depth)

P_i = Initial Reservoir pressure, psia

Z_i = Compressibility at P_i and T_f

To calculate **recoverable gas volumes**, the OGIP is multiplied by a recovery factor. Volumetric depletion of a gas reservoir with reasonable permeability at conventional depths in a conventional area will usually recover 70 to 90% of the gas-in-place. However, a reservoir's recovery factor can be significantly reduced by factors such as: low permeability, low production rate, overpressure, soft sediment compaction, fines migration, excessive formation depth, water influx, water coning and/or behind pipe cross flow, and the position and number of producing wells. As an example, a 60% recovery factor might be appropriate for a

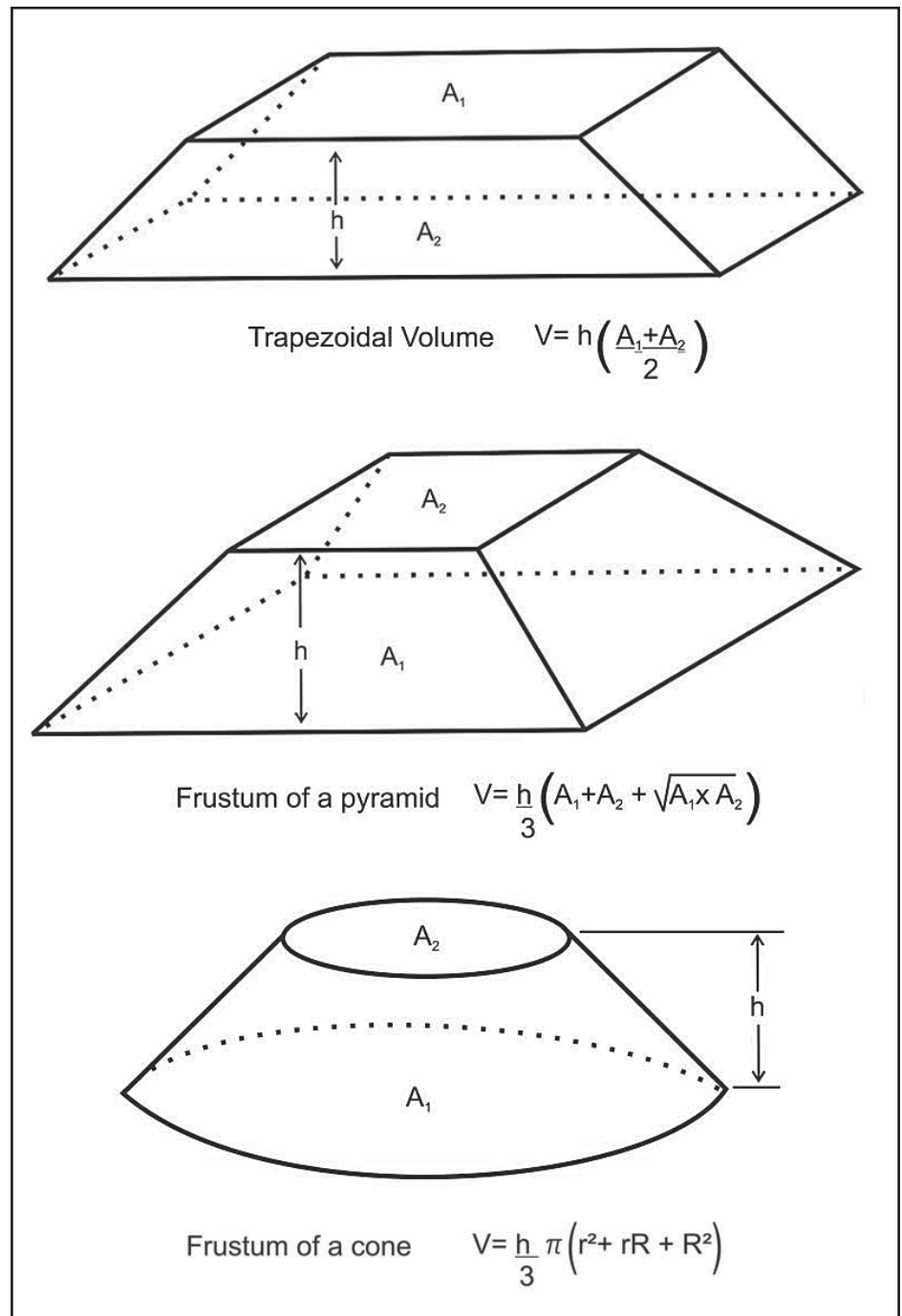


Figure 3. Volumetric Rules: Trapezoidal, Pyramidal, and Cone.

gas accumulation overlying a strong aquifer with near perfect pressure support.

Rock Volume Calculations (A * h)

Reservoir volumes can be calculated from net pay isopach maps by planimetry to obtain rock volume (A * h). To calculate volumes it is necessary to find the areas between isopach contours. Planimetry can be performed by hand or computer generated. Given the areas between contours, volumes can be computed using; Trapezoidal rule, Pyramidal rule, and/or the Peak rule for calculating volumes (see Figure 3).

Net pay

Net pay is the part of a reservoir from which hydrocarbons can be produced at economic rates, given a specific production method. The distinction between gross and net pay is made by applying cut-off values in the petrophysical analysis (Figure 4). Net pay cut-offs are used to identify values below which the reservoir is effectively non-productive.

In general, the cut-off values are determined based on the relationship between porosity, permeability, and water saturation from core data and capillary pressure data. If core

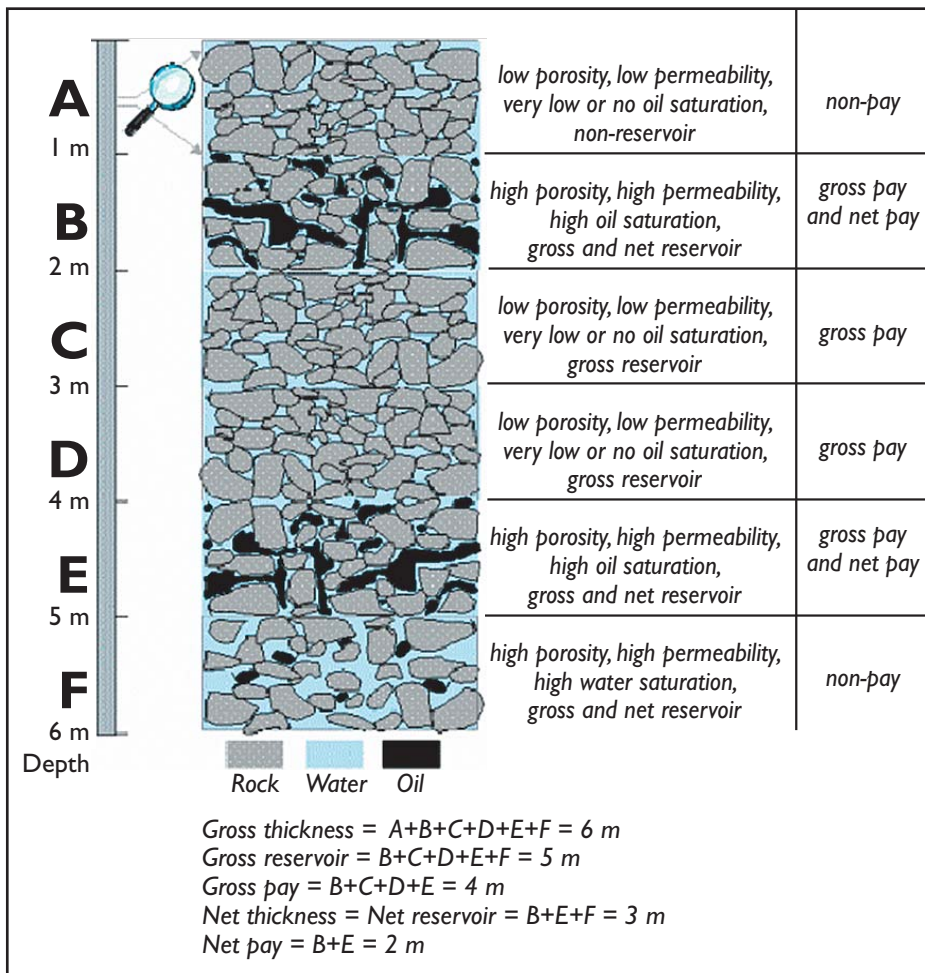


Figure 4. Gross and Net Pay Distinction.

is unavailable, estimation of a cut-off can be derived from offset well information and comparative log signatures.

Porosity and Water Saturation

Porosity values are assigned as an average over a zone (single well pool) or as a weighted average value over the entire pay interval using all wells in a pool. Similarly, the average thickness-weighted water saturation using all wells in the pool is commonly assumed as the pool average water saturation.

Drainage Area

Drainage area assignments to wells should be similar to offset analogous pools depending on the geological similarities and productivity of the wells within the analog. Pressure information is useful in estimating pool boundaries and if any potential barriers exist between wells. Seismic analysis usually improves the reservoir model and provides for more reliability in reserve or resource estimates.

Formation Volume Factor

The volumetric calculation uses the initial oil or gas formation volume factor at the initial

reservoir pressure and temperature. Both B_o and B_g are functions of fluid composition, reservoir pressure and temperature and consequently of reservoir depth. The B_o and B_g values from analogous offset pools are often used as an initial estimate for the prospect under consideration.

VOLUMETRIC UNCERTAINTY

A volumetric estimate provides a static measure of oil or gas in place. The accuracy of the estimate depends on the amount of data available, which is very limited in the early stages of exploration and increases as wells are drilled and the pool is developed. Article 8, entitled Monte Carlo Analysis, will present a methodology to quantify the uncertainty in the volumetric estimate based on assessing the uncertainty in input parameters such as:

- Gross rock volume – reservoir geometry and trapping
- Pore volume and permeability distribution
- Fluid contacts

The accuracy of the reserve or resource estimates also increases once production

data is obtained and performance type methods such as material balance and decline analysis can be utilized. Finally, integrating all the techniques provides more reliable answers than relying solely on any one method.

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Look for our next article on "Decline Analysis" in the January issue of the Reservoir.

This article was contributed by Fekete Associates, Inc. For more information, contact Lisa Dean at Fekete Associates, Inc.

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