Geomechanical Reservoir Models

Subtopics:

- Porosity and Formation Compressibility
  - Hall
  - Dobrynin
- Pressure-Dependent Permeability
  - Yilmaz and Nur
  - Dobrynin

Geomechanical models simulate changes in rock properties with time and pressure. In performance based reservoir analysis, a geomechanical model may be coupled with a Flowing Material Balance, Typecurve, Analytical, Numerical, or Unconventional Reservoir Module analysis. Geomechanical models are useful for, and may be necessary additions to, analyses of overpressured reservoirs. The primary properties of interest are porosity, formation compressibility (pore compressibility) and permeability. The impact of these properties on the fluid flow model are discussed in the following sections.

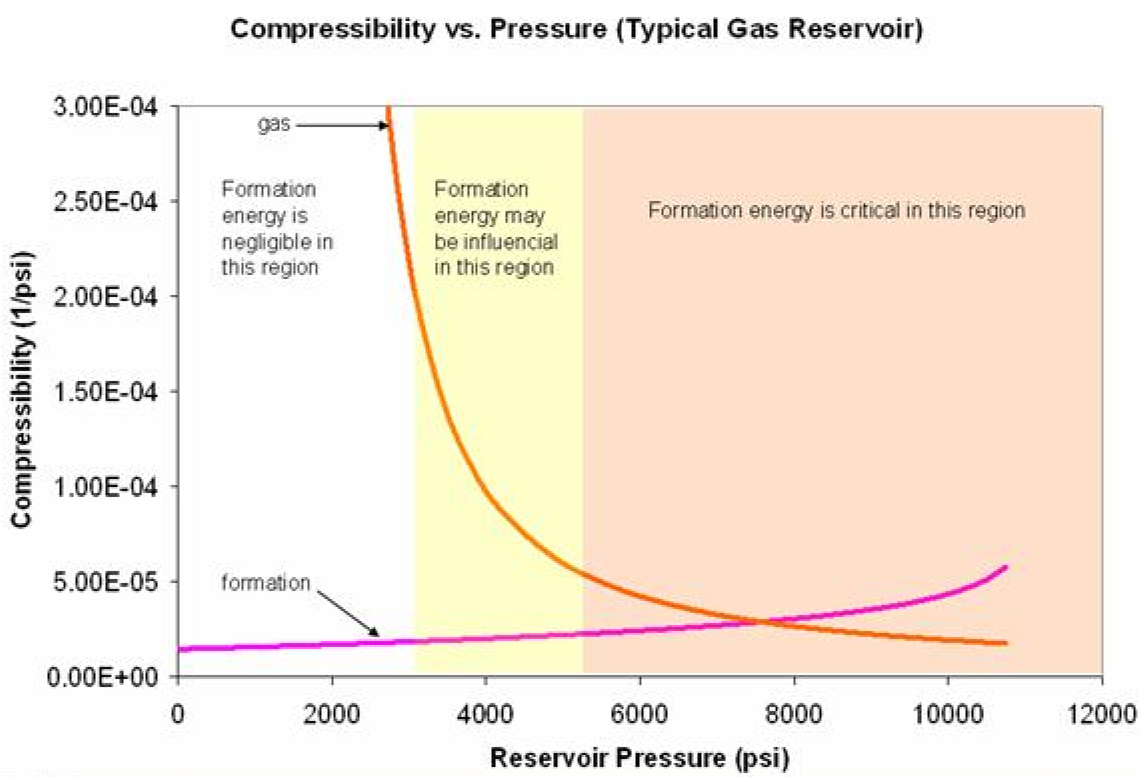
Porosity and Formation Compressibility

Pore volume and pore volume compressibility are related through the following equation:

$$c_f = \frac{1}{V_p}\frac{dV_p}{dp}$$

In normally pressured reservoirs, the pore volume change with pressure is considered minimal, and thus the pore volume (formation) compressibility retains a very small, constant value. However, in overpressured reservoirs, the natural compaction process is incomplete, as a large portion of the overburden remains supported by high internal pore pressure. As this pressure is released through fluid production, the pore space may reduce significantly. Thus, under overpressured conditions, formation compressibility is relatively large, and may have significant variation with pressure. This becomes important to the material balance equation, as the pore compressibility is a significant energy term in overpressured reservoirs.

In normally pressured gas reservoirs, the energy of the formation is usually negligible, compared to the energy of the gas. In oil reservoirs, the formation compressibility may be significant at any pressure. The graph below compares the energies (compressibilties) of formation and fluid (gas) over a large pressure range. In areas where they are near the same order of magnitude, the formation compressibility cannot be ignored.



For overpressured reservoirs, there are very few published correlations. Most appear to be highly specific to area and rock-type, and thus are not useful for universal application.

Hall

The most well-known and used correlation for formation compressibility was developed by Hall, and is a function only of porosity. The Hall correlation is based on laboratory data and is considered reasonable for normally pressured sandstones. It tends to underpredict formation compressibility under high pressure conditions. This correlation is used when calculating initial formation compressibility on the Basic Reservoir Properties view.

$$c_f = 1.87 * 10^{-6}\ \phi^{-0.415}$$

Dobrynin

The Dobrynin (1962) correlation can predict a relative change in formation compressibility over a range of net overburden pressures. It is designed for overpressured reservoirs. The correlation assumes a semi-logarithmic relationship between formation compressibility and net overburden pressure between two limiting pressures, p_{min} and p_{max}. However, it does not predict the initial formation compressibility.

$$c_f = \frac{c_{f\,max}}{\log\left(\frac{p_{max}}{p_{min}}\right)} \log\left(\frac{p_{max}}{p_n}\right)$$

$$f_c = \frac{c_f}{c_{fi}} = \frac{\log\left(\frac{p_{max}}{p_n}\right)}{\log\left(\frac{p_{max}}{p_{ni}}\right)}$$

$$p_e = p_{grd} * Depth$$

$$p_n = p_e - \alpha\, p$$

Laurent et al. (1993) propose an empirical correlation for Biot Coefficient (α):

$$\alpha = 1.75\, \phi^{0.51}$$

The Dobrynin correlation is considered a reasonable predictor of variation in formation compressibility, provided that the following conditions are met:

- Net overburden pressure must lie within the range of pmin and pmax (usually 150 to 30,000 psi)
- Overburden pressure must be higher than the product of the initial pressure and Biot's number (initial net overburden pressure must be greater than zero)

The Dobrynin correlation may be used to generate a continuous compressibility profile using a known formation compressibility value:

- Initial formation compressibility (usually between 10 and 80 microcips for overpressured reservoirs)
- Overburden pressure gradient (Pgrd, psi/ft)
- Reservoir depth (ft)

Formation compressibility is then solved for any value of pressure.

Pressure-Dependent Permeability

In the standard pressure transient equations, permeability is usually considered to be constant. However, there are several situations in which this assumption may not be a valid:

- Compaction in overpressured reservoirs
- Very low permeability reservoirs in general
- Unconsolidated and/or fractured formations

Variable permeability is an important (and sometimes critical) consideration, with regards to the fluid flow model. As a result of pore volume reduction during fluid withdrawal, the available flow area is reduced, and thus the permeability decreases with pressure. As with formation compressibility, the variable permeability effect is greatest under overpressured conditions. The process of pore volume collapse in overpressured reservoirs is referred to as compaction.

One way to account for a variable permeability over time is to modify the definition of pseudo-pressure and pseudo-time. Another way to account for variable permeability is through the use of formation compressibility correlations.

Yilmaz and Nur

Yilmaz and Nur present a generic correlation, suitable for the pressure variable permeability observed in extremely low permeability reservoirs. The correlation introduces a "permeability modulus" (γ) which has a form identical to compressibility. The magnitude of the permeability modulus is a strong function of the formation compressibility.

$$\gamma = \frac{1}{k}\frac{dk}{dp}$$

$$\frac{k}{k_i} = e^{-\gamma(p_i - p)}$$

Dobrynin

Dobrynin presents a more detailed correlation, designed for overpressured reservoirs, that relates the fractional change in permeability due to formation compressibility, overburden pressure and a dimensionless correlation factor (γ). Between a certain minimum and maximum pressure range (p_{min} and p_{max}), this correlation produces a semi-log straight line.

$$\frac{\Delta k}{k} = 2(1+\gamma)c_f^{max}\left[p_{min} + \frac{p_o}{\log\left(\frac{p_{max}}{p_{min}}\right)}\left[\log\left(\frac{p_{max}}{p_o}\right) + 0.434 - \frac{p_{min}}{p_o}\left[\log\left(\frac{p}{p_{min}}\right) + 0.434\right]\right]\right]$$

where:

γ is 0.33 for uniform pore distribution or very high pore compressibility, higher for poorly sorted sandstones with low pore compressibility.

The equation below relates the permeability at any pore pressure to that at conditions of zero net overburden pressure:

$$\frac{k_p}{k} = 1 - 2(1+\gamma)c_f^{max}\left[p_{min} + \frac{p_i - \alpha\bar{p}}{\log\left(\frac{p_{max}}{p_{min}}\right)}\left[\log\left(\frac{p_{max}}{p_i - \alpha\bar{p}}\right) + 0.434 - \frac{p_{min}}{p_i - \alpha\bar{p}}\left[\log\left(\frac{p_{max}}{p_{min}}\right) + 0.434\right]\right]\right]$$

It is more suitable to have an equation that relates permeability at any pressure to permeability at initial conditions, thus we rewrite the above as follows.

$$\frac{k_p}{k_i} = \frac{\frac{k_p}{k}}{\frac{k_i}{k}} = \frac{1 - 2(1+\gamma)c_f^{max}\left[p_{min} + \frac{p_e - \alpha\bar{p}}{\log\left(\frac{p_{max}}{p_{min}}\right)}\left[\log\left(\frac{p_{max}}{p_e - \alpha\bar{p}}\right) + 0.434 - \frac{p_{min}}{p_e - \alpha\bar{p}}\left[\log\left(\frac{p_{max}}{p_{min}}\right) + 0.434\right]\right]\right]}{1 - 2(1+\gamma)c_f^{max}\left[p_{min} + \frac{p_e - \alpha p_i}{\log\left(\frac{p_{max}}{p_{min}}\right)}\left[\log\left(\frac{p_{max}}{p_i - \alpha p_i}\right) + 0.434 - \frac{p_{min}}{p_i - \alpha p_i}\left[\log\left(\frac{p_{max}}{p_{min}}\right) + 0.434\right]\right]\right]}$$

where:

Biot's Number default: *0.85 to 1*

Maximum Formation Compressibility default: *30 to 80 microcips*

Pmax = 30,000 psi

Pmin = 150 psi