Modified Athy-Law Compaction to Account for Porosity Generation and Preservation from Kerogen Conversion in Terzaghi-Like Models of Petroleum Source Rocks*

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Abstract

A new algorithm is proposed and calibrated for assessing the effect of organic matter on compaction, porosity generation, and porosity preservation in organic-rich fine-grained sediments at various maturities. The algorithm involves the addition of simple terms to the Athy-Law exponent relating porosity to effective stress in Terzaghi-like compaction models, which are often used in basin and petroleum systems models to calculate expulsion of water and petroleum from source rocks. The central concept in these models is that porosity is related to the difference between vertical lithostatic pressure and pore pressure, and pore pressure is calculated from a simple permeability model, either 0D or 1D. The new model presented here is empirical and requires calibration for the source rock of interest. It considers that because kerogen is softer than most inorganic grains, when in high concentration, it can lead to lower rock porosity prior to catagenesis. This part of the model was calibrated for the Green River Formation using log data at 600-700 m that shows porosity decreasing from 15-25% to about 7% as the kerogen volume fraction increases from negligible to 50 vol%. In addition, the new model was designed to consider that preservation of porosity created from kerogen conversion can be related to its geometric shape and the ductility of the surrounding mineral grains. Model results are shown for the ranges of residual kerogen porosities observed in source rocks. The model has been incorporated into TRESORS, a 0D simulator of source rock maturation and expulsion at both laboratory and geological conditions.

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Stanford Total Enhanced Modeling of Source rock

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AAPG ACE, Houston, TX, 2-5 April 2017

Presented by M. Cremon, A. K. Burnham, Y. Liu, and A. Lapene

Stanford University, Stanford CA, and Total E&P R&D, Pau France

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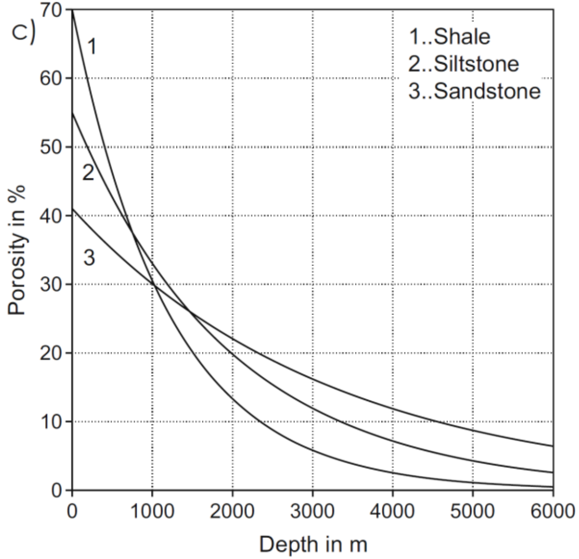
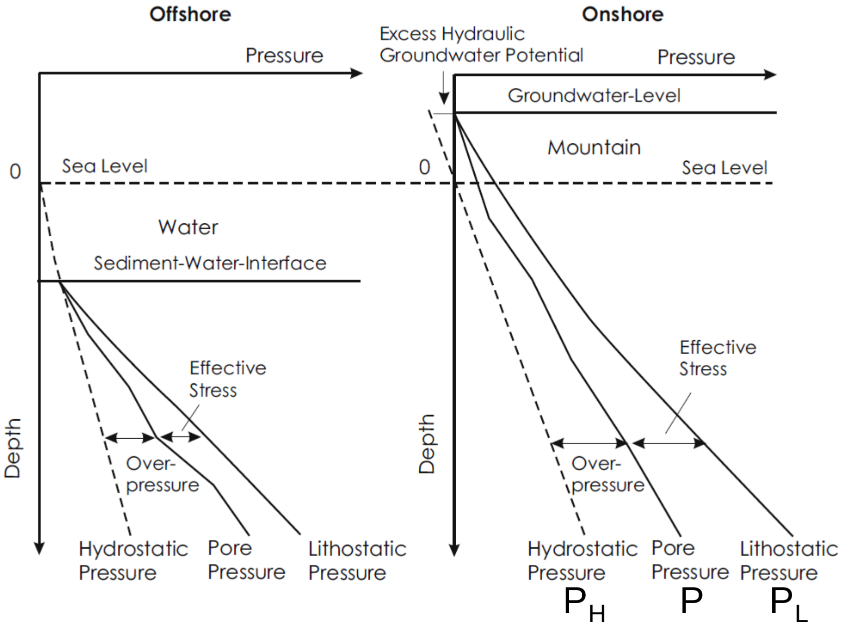
Common compaction modeling laws

Athy (1930):
Exponential decline of porosity with depth



Terzaghi (1923):
Exponential decline of porosity with effective stress (P_L-P)



Examples from Hantschel and Kauerauf, Fundamentals of Basin and Petroleum Systems Modeling, Springer, 2009

Key questions for modeling porosity evolution

How does porosity evolve in mixtures of brittle and ductile materials?

- Clay and kerogen are more ductile than quartz, silicates, and carbonates
- Related to the classical discussion of whether kerogen is load bearing or pore filling

How does the porosity evolve with kerogen conversion?

- Conversion of kerogen to oil and gas creates void space amounting to 20-80 % of the kerogen volume depending on Hydrogen Index
- How much of this generated porosity is lost immediately and during subsequent burial?

Note: The initial discussion uses Athy's law as an example with the understanding that compaction in the absence of organic matter is more complicated than a single exponential

Green River Formation porosity depends strongly on organic content

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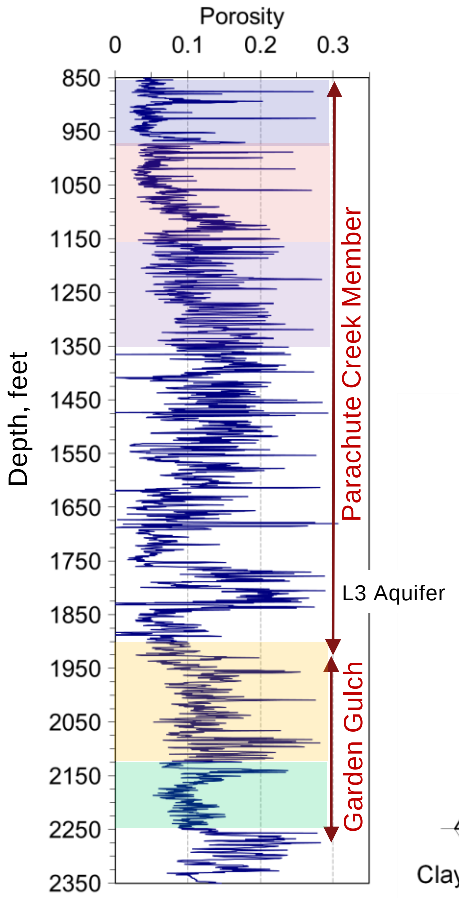
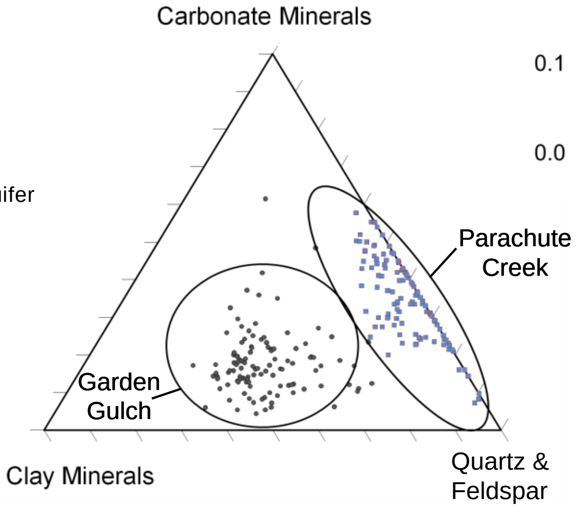
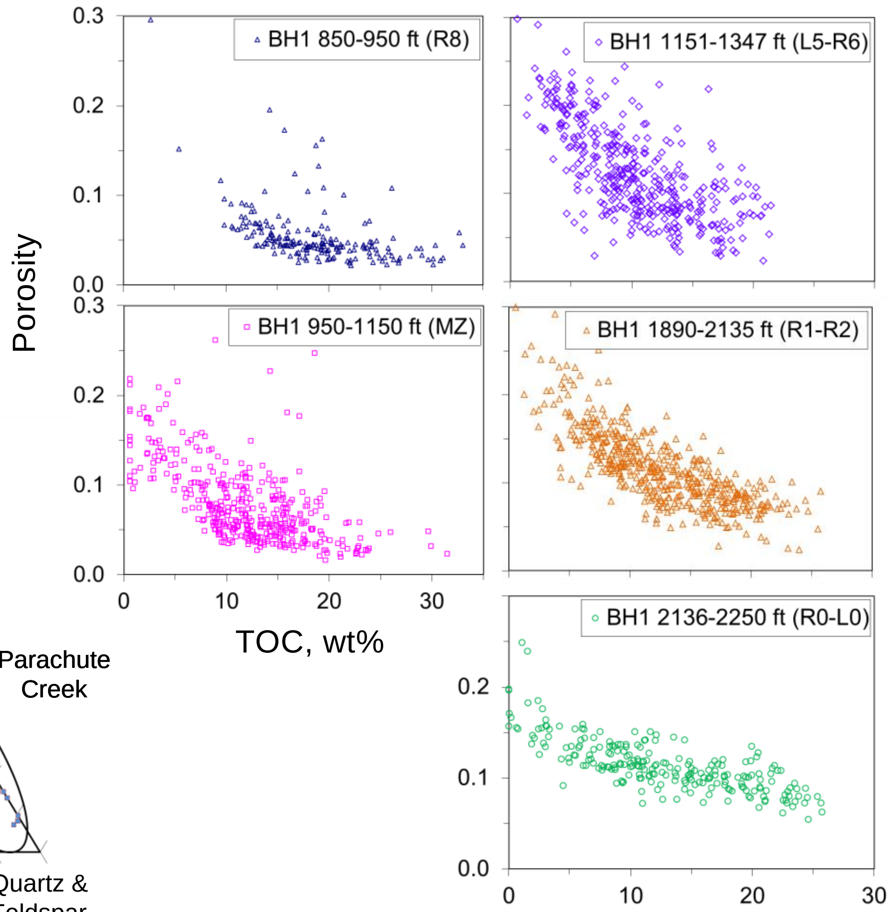




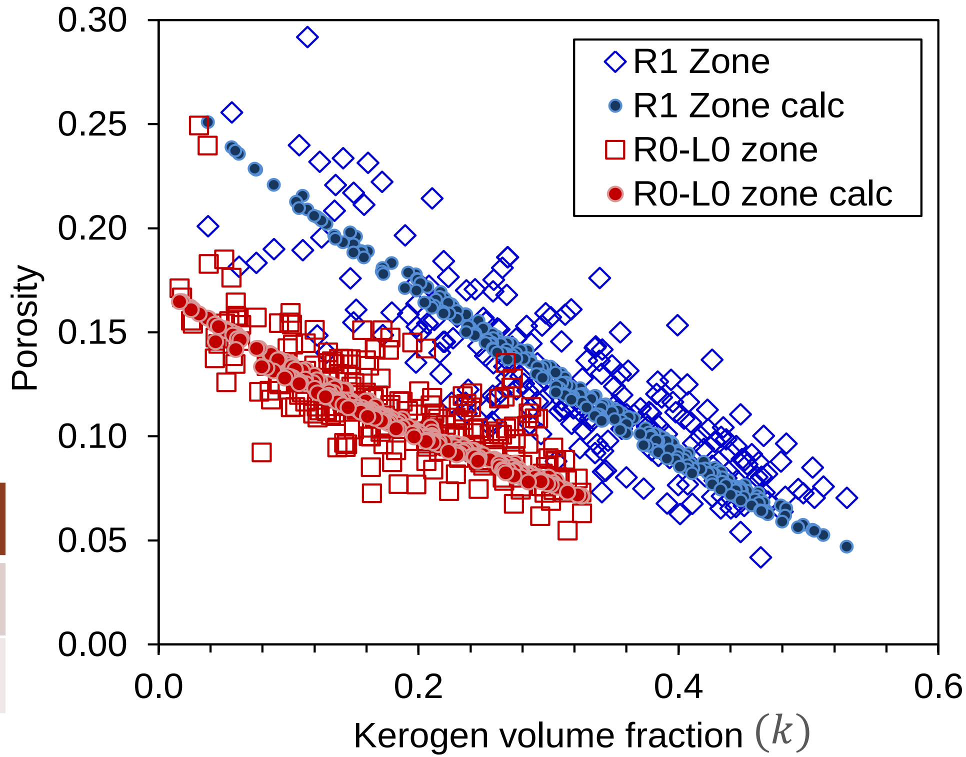


Adjusting Athy's Law for organic content

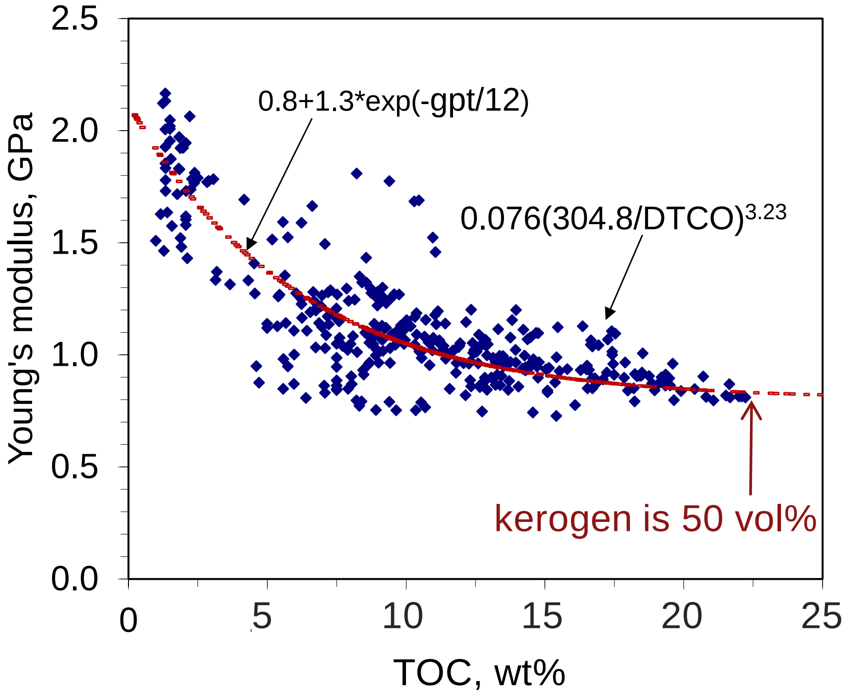
$$\varphi = \varphi_0 e^{-ad/(1-k^n)}$$

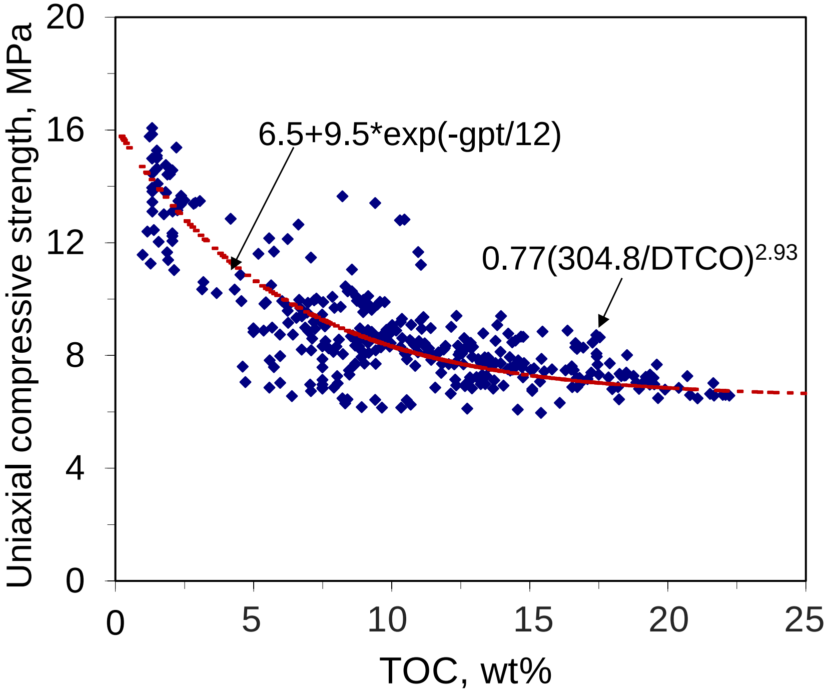
φ is porosity
d is depth
a is a compaction coefficient
k is kerogen volume fraction
n is an organic grain compaction correction

Interval	Depth, ft	φ_0	a	n
R1	2014-2135	0.6	0.0011	0.5
R0-L0	2135-2250	0.5	0.0016	0.7



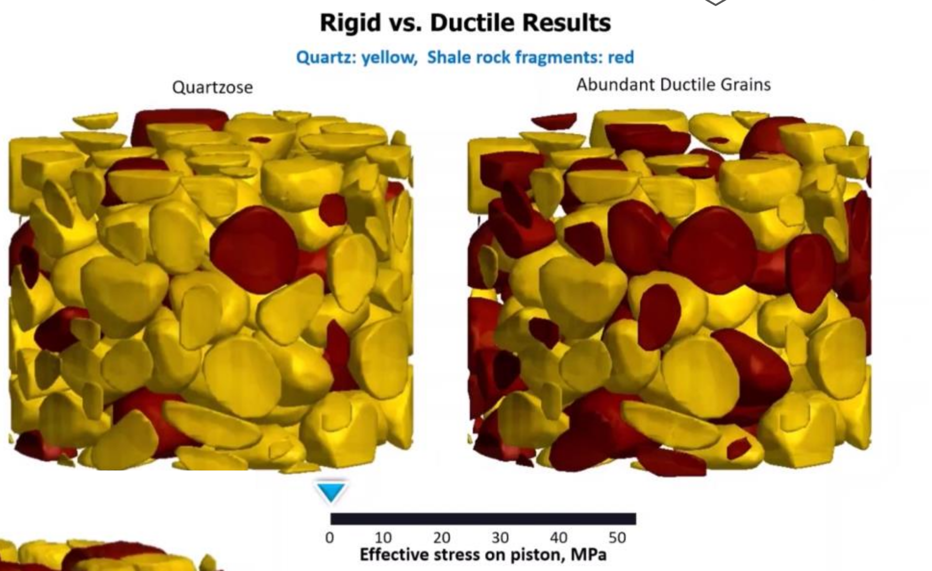
Kerogen reduces porosity because it is softer



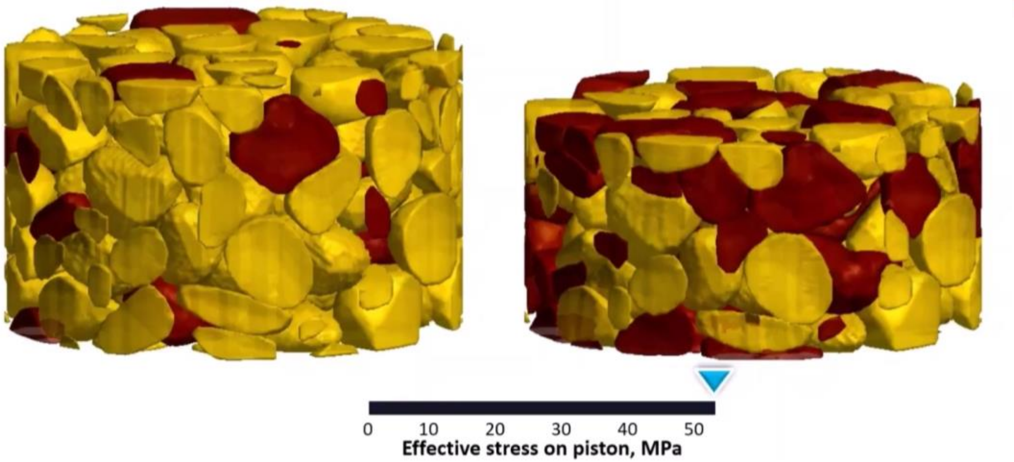


DTCO is the sonic log compressional wave arrival time; gpt = gal/ton ≈ 2×TOC
Asymptotic limit of Young's modulus is the same as for high-density polyethylene

Clay-quartz mixtures have analogous enhanced compaction



Ductility of clay enables more deformation and compaction under lithostatic load corresponding to ~6600 ft of burial



From Linked-In PSA Webinar #5 by Rob Lander of UT Austin

Clay has a smaller effect on porosity than kerogen for the Green River Formation

Clay mineral content determined by Schlumberger ELAN

Clay is uncorrelated to anti-correlated with kerogen content depending on depth interval

Porosity correlates weaker with clay than kerogen content

Parameter fits including both kerogen and clay content are negligibly better than for kerogen alone

$$porosity = (a + b*clay)*\exp(-c*kerogen)+d$$

Kerogen conversion modifies Athy's Law

Kerogen conversion creates porosity

- 20-80% of kerogen volume, depending on HI
- A large fraction has pore diameters less than 100 nm

Does this porosity cause a positive deviation from Athy's law?

- It will not if the porosity is easily filled by rearrangement of surrounding mineral grains
- It will if the porosity is stable due to mineral bridges
- Compaction likely depends on ductility of mineral matrix (Fishman et al., 2012)
- Compaction efficiency likely depends on kerogen geometry (globular versus lenticular)

Why do we care? Compaction likely affects expulsion efficiency

- Generation of oil and gas increases organic volume by only ~20% at generation T & P
- Sorption capacity of kerogen may depend on applied lithostatic load
- Expulsion may depend on hydrocarbon saturation level of pore fluids (relative permeability)

Porosity generated is calculated simply from mass and volume balance

Generated porosity

$\varphi_k = \rho_R \times (K_i/\rho_i - K_r/\rho_r) = \rho_R \times K_i(1/\rho_i - f_r/\rho_r)$

ρ_R = density of rock

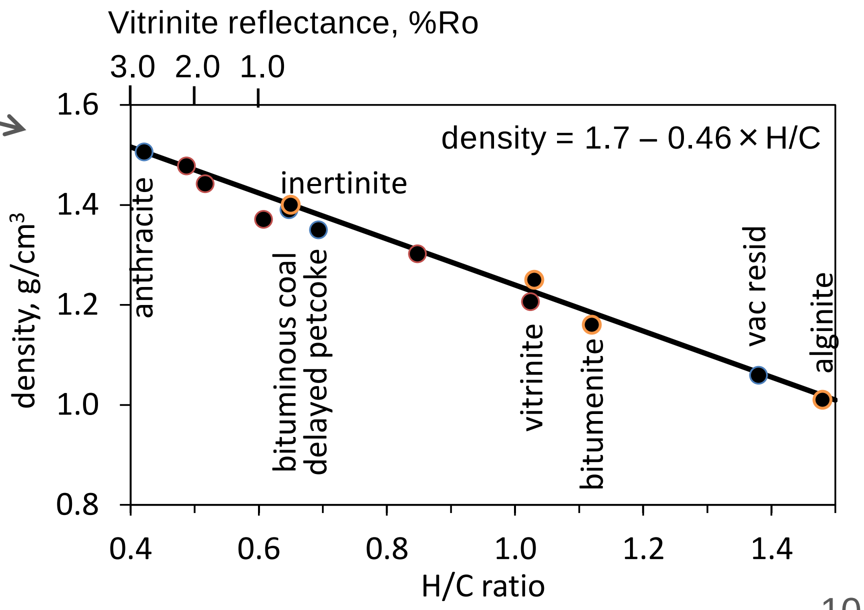
ρ_i = density of immature kerogen

ρ_r = density of residual kerogen

K_i = mass fraction of immature kerogen

K_r = mass fraction of residual kerogen = $f_r \times K_i$

f_r = mass fractional conversion of immature to mature kerogen



Measured and calculated porosities agree well for low applied stress

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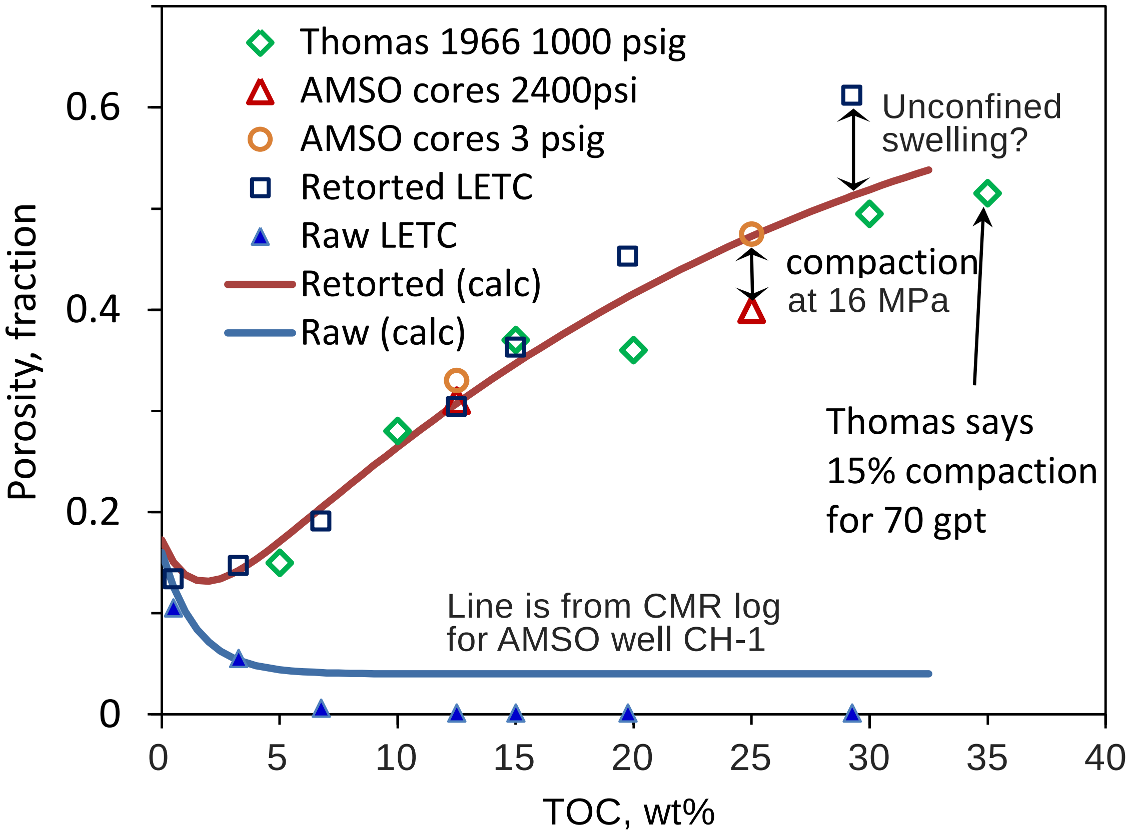

From Burnham (2017)

Mature source rock porosity is largely within residual organic matter

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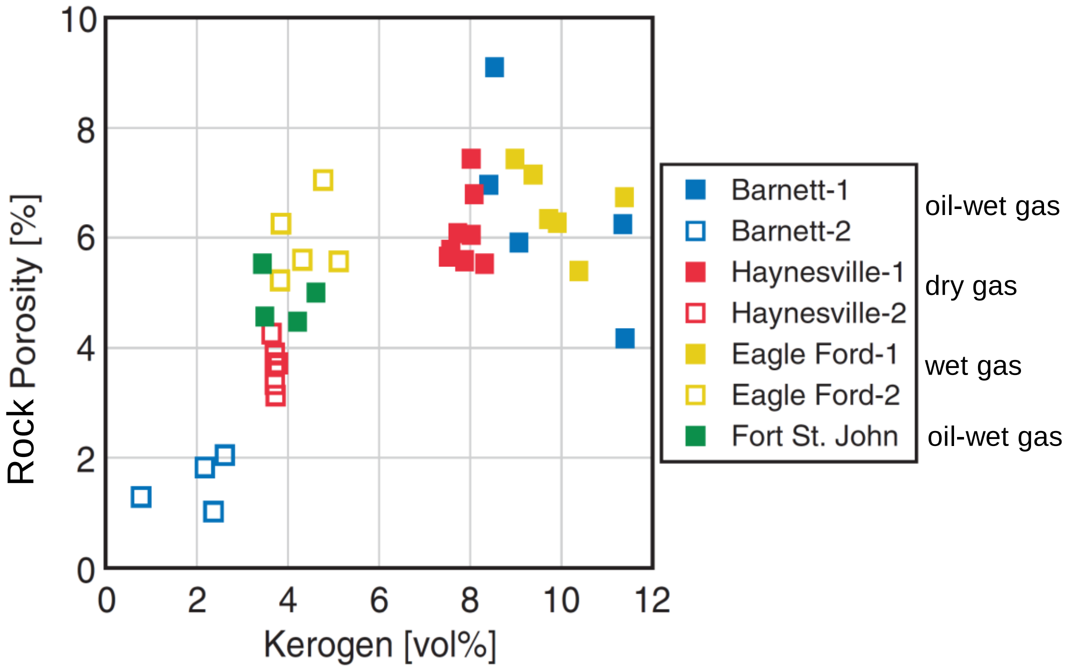
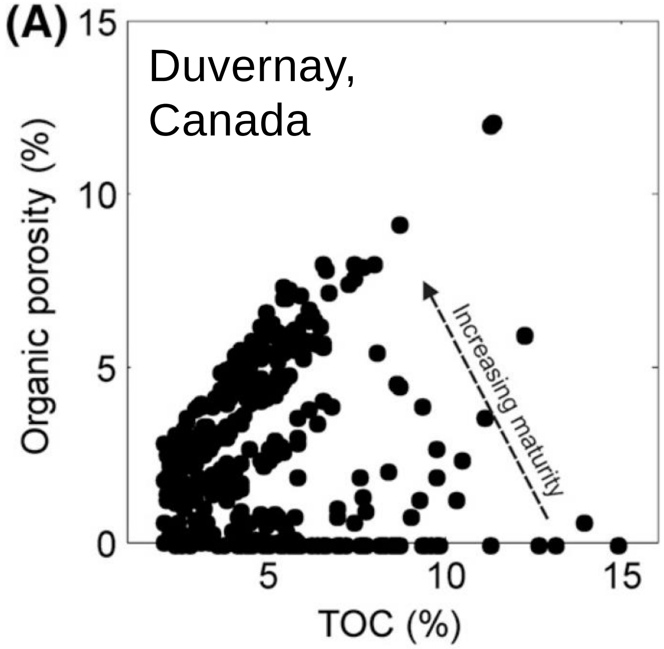
From Sone and Zoback (2013)



From Chen and Jiang (2016)



Athy's Law corrected for additional porosity from kerogen conversion

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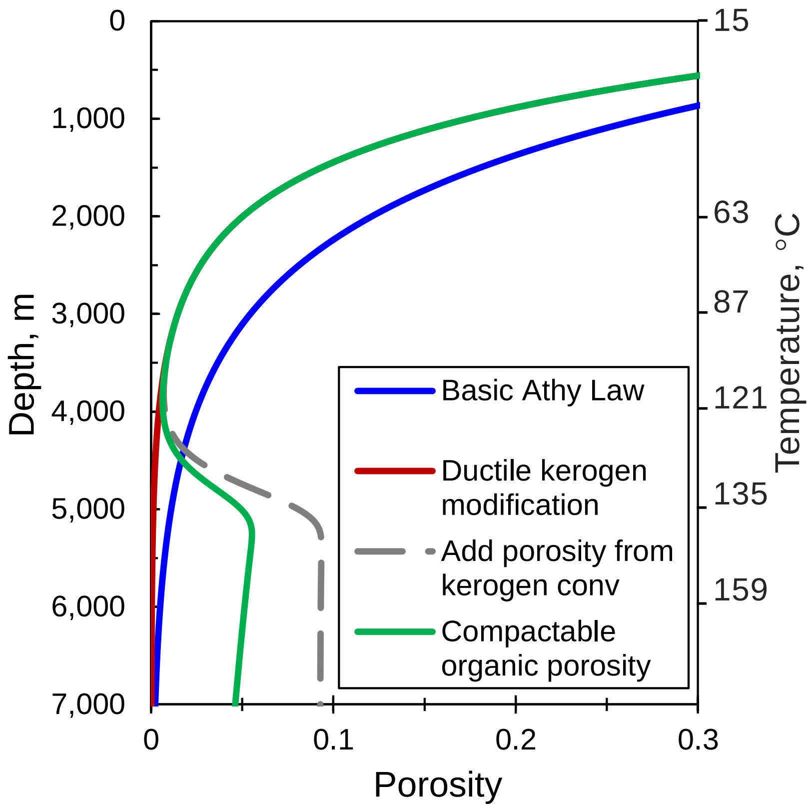
$$\varphi = \varphi_0 e^{-ad/(1-k_i{}^n)} + \varphi_k e^{-bd}$$

φ is porosity
φ_0 is initial porosity at burial
φ_k is porosity from kerogen decomposition
d is depth
a is a mineral porosity compaction coefficient
k_i is initial kerogen volume fraction
(perhaps labile kerogen only)
n is an organic grain compaction correction
b is a kerogen porosity compaction coefficient

6 wt% Type I kerogen $\Rightarrow$ 12.6 vol%
35% converted to residual kerogen $\Rightarrow$ 3.3 vol%
Single first-order reaction
φ_0 = 0.6; a=0.0008; n=0.5; b=0.0002

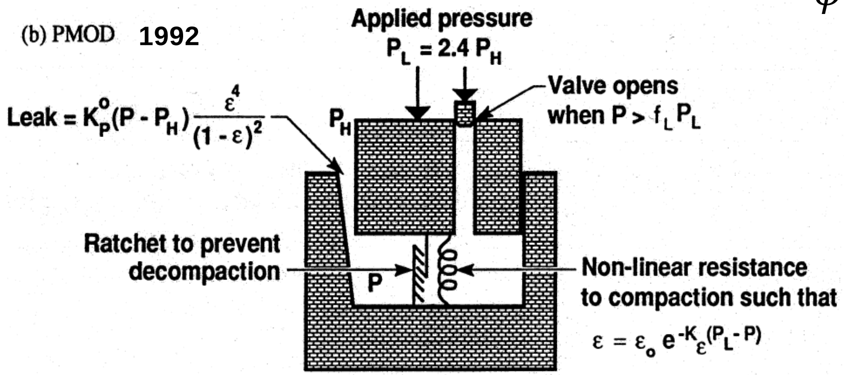


Alternate and additional approaches provide better agreement for complex systems

Use effective stress instead of depth

Include a fracture pressure relief valve

Include a residual irreducible baseline porosity



From Braun and Burnham (1992)

Example:

$$\varphi = \varphi_0 e^{-K_\varepsilon (P_L - P)/(1-k_i{}^n)} + \varphi_k e^{-K_k (P_L - P)} + \varphi_{ir}$$

φ_k is porosity from kerogen conversion
K_ε is a mineral compaction coefficient
K_k is a kerogen compaction coefficient
φ_{ir} is the irreducible porosity
P is the pore pressure
P_L is the lithostatic pressure
P_H is the normal hydrostatic pressure

Summary and Conclusions

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- Ductility of kerogen causes greater compaction for richer source rocks
  - Similar to observations by others for clay in quartz matrices
  - CMR and other logging tools can be used to gather much more data than laboratory measurements to better discern trends and calibrate appropriate models
  - Unambiguous trends were observed for the Green River Formation in the Piceance Basin and used to calibrate a simple enhanced-compaction model
- Generation of porosity from kerogen decomposition is well known but preservation is not well quantified
  - Data in the literature is relatively sparse with large scatter
  - Others have suggested that ductility of mineral matrix dominates porosity preservation
  - Several empirical functional forms were suggested for modeling preservation and compaction but await better data for calibration
- These effects have been incorporated into the in-house single-cell compositional kinetics-fluid flow-geomechanics computer code TRESORS currently under development through TOTAL E&P R&D

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