A New Method to Predict Organic Matter Porosity in Unconventional Shale Reservoirs
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Abstract

A new model is proposed to predict organic matter porosity in unconventional shale reservoirs based on scanning electron microscopic (SEM) observations from major productive shale reservoirs in North America. These observations reveal that most of the “effective” porosity within organic matter is secondary in origin, and occurs within void-filling organic matter, interpreted as solid bitumen (pyrobitumen), rather than in kerogen, as assumed in previous shale reservoir prediction models. The origin of the void-filling bitumen is interpreted as a thermal alteration product of residual oil retained within the rock matrix pores. Pores are interpreted to develop within the solid bitumen as a result of thermal cracking and gas generation at elevated levels of thermal maturity to form insoluble pyrobitumen. This process may be analogous to the generation of pores within petroleum coke during the refining of heavy crude oils. The new organic porosity prediction model requires: 1) an estimation of preserved mineral matrix porosity at the onset of oil generation based on compaction curves and burial history models, 2) average peak oil saturation (oil saturation index), and 3) the fraction of organic matter converted to porosity (porosity conversion ratio). The last two parameters are derived from SEM digital image measurements from analogous shale reservoirs. Further research is required to refine and test the proposed porosity prediction model.

Statement of the background

Previous shale reservoir quality prediction models are based on a conceptual material (mass) balance model that assumes the volume of pores in organic matter is equal to the volume of oil generated during the thermal decomposition of labile (oil-generative) kerogen. This kerogen porosity model was first proposed by Jarvie et al. (2007) as the inferred process for the origin of pores in gas shales, which were later described from early scanning electron microscopic (SEM) images of the Barnett gas shale in central Texas (Loucks et al., 2009). The kerogen porosity model proposed by Modica and Lapierre (2012), and later modified by Chen and Jiang (2016), uses geochemical and thermal maturity measurements to estimate the original volume of labile kerogen and the volume of kerogen transformed to oil to predict organic matter porosity.

Aims and Objectives

The purpose of this study is to develop an improved reservoir quality prediction model for unconventional shale reservoirs based on an alternate pyrobitumen porosity model that is constrained by high-quality...
SEM petrographic observations and measurements. See Camp (in press) for a more detailed version of this study.

Materials and Methods

Petrographic observations of numerous SEM images from the major producing shale reservoirs in North America were used to develop an alternate pyrobitumen porosity model. Evaluated samples were acquired from fresh cores by Anadarko Petroleum from a variety of U.S. shale plays, including the Marcellus and Utica in Pennsylvania and Ohio, the Haynesville, Eagle Ford and Wolfcamp in Texas, and the Niobrara and Mowry in Colorado and Wyoming. Secondary and backscattered electron images were acquired from uncoated, Ar-ion milled surfaces using field-emission SEM at relatively low electron beam energy (10-15 keV) under high pressure vacuum conditions.

Samples from oil mature (0.94-1.3 %Ro) Wolfcampian strata from four wells in the Delaware Basin, Texas were examined to quantify porosity, and organic and mineral content. These parameters were quantified from type II secondary electron (SE2) images acquired at 10 nm/pixel resolution using proprietary computer digital image analysis by Ingrain (ZoneID®) as described by Walles et al. (2016). Type II secondary electrons originate from below the specimen surface and therefore are less affected by surface rugosity than standard type I secondary electrons (Huang et al., 2013). The digital SE2 images were segmented to measure the following parameters used in the porosity prediction model: 1) total porosity (ΦIT), 2) porosity associated with organic matter (PAOM), and 3) total organic matter (TOM).

Results and Discussion

The pyrobitumen porosity model is based on the hypothesis that the effective organic matter porosity occurs within an interconnected network of secondary, void-filling organic matter, interpreted as solid bitumen (pyrobitumen) (Camp, 2015; 2016). The origin of the pyrobitumen, referred to as organic matter cement (Camp, in press), is thought to be a thermal alteration product of residual oil retained within matrix pores and other voids in the source rock following primary migration (Cardott, 2015). This model for the origin of pores also applies to organic matter cements derived from migrated oil expelled from source rocks that occlude mineral matrix pores within clastic or carbonate reservoirs, such as observed within the unconventional Montney siltstone tight gas reservoir (Wood et al., 2015).

Predicting the amount of organic matter porosity based on the pyrobitumen porosity model involves estimating two main parameters: 1) the total amount of organic matter cement, and 2) the fraction of organic matter cement converted to pores. The total amount of organic matter cement is a function of the amount of mineral matrix porosity preserved at the onset of oil generation. This is determined using compaction profiles in combination with burial history models (Figure 1). Because porosity loss by compaction varies by grain size and composition, it is important to select compaction curves that are representative of the lithology of the specific mudstone under study, such as the compaction profiles of Kominz et al. (2011) and Fabricius et al. (2008).

For example, a siltstone with an initial porosity of 70% is reduced by mechanical compaction to 20% at the estimated depth of the onset of oil generation (0.6%Ro) modeled at a restored maximum burial depth of 10,000 ft (3000 m) (Figure 1b). This 20% preserved porosity value represents the estimated maximum amount of potential organic matter cement, assuming 100% oil saturation.

The amount of organic matter cement is also a function of the degree of oil saturation resulting from peak oil generation and primary migration. Scanning electron images reveal that the amount of organic matter cement occluding mineral matrix pores is variable. The degree of organic matter cementation is a reflection of the effectiveness of the source rock to generate sufficient amounts of oil to saturate the mineral matrix pore space, and the connectivity between mineral matrix pores.

Digital image analysis of analogous shale reservoirs is used to calculate an organic saturation index (OSI) by dividing the total organic matter cement by the amount of mineral matrix porosity prior to organic cementation, as shown by equation 1. The amount of organic matter cement is measured by the sum of
the total organic matter (TOM) and the pores associated with organic matter (PAOM). The amount of mineral matrix porosity prior to organic matter cementation is measured by the sum of the total mineral matrix porosity ($\Phi_T$) and TOM:

$$OSI = \frac{(TOM + PAOM)}{(\Phi_T + TOM)}.$$  \hfill (1)

Assuming a 90% OSI derived from analogs, the 20% maximum potential amount of organic matter cement in the siltstone example is reduced to 18% (20% matrix porosity x 90% OSI).

The residual oil retained within mineral matrix pores is interpreted to become progressively altered with increased burial and thermal maturation such that the original liquid oil is converted to solid bitumen. The formation of this void-filling, solid organic matter acts as an effective cement, further reducing the porosity of the siltstone example to 2% remnant matrix porosity (18% organic matter cement) by the end of the oil generation window.

The organic matter cement is further transformed with secondary pores developing within the organic matter forming pyrobitumen in the gas maturity window (typically vitrinite reflectance > 1.0 %Ro). This process may be similar to the generation of pores within petroleum coke during the refining of heavy crude oils (Picon-Hernandez et al., 2008). The degree of organic matter porosity development observed in SEM images is highly variable, even within the same sample and same field of view. Other researchers have reported organic matter porosity measured from SEM images ranging from <1 to 50% (Curtis et al., 2010; Loucks et al., 2009, 2012; Milliken et al., 2013).

An organic porosity conversion ratio (PCR) is calculated after Driskill et al. (2013) by dividing the porosity associated with organic matter (PAOM) by the sum of PAOM and the TOM measured from analog SEM images:

$$PCR = \frac{PAOM}{(PAOM + TOM)}.$$  \hfill (2)

Measurements from digital SEM images of the Wolfcamp shale resulted in organic PCR values that ranged between 0.7 and 28.7% (mean 13.9%). The predicted average organic matter porosity is calculated by the product of the percent of organic matter cement and the mean PCR. Using the Wolfcamp as an analog for the siltstone example, the resulting predicted average organic matter porosity is 2.5% (18% organic matter cement x 13.9% PCR).

The validity and utility of the proposed pyrobitumen porosity prediction technique requires further testing and calibration by additional measurements from SEM images or other methods. The current model is limited by the assumptions that any porosity reduction by mineral cementation during early diagenesis (pre-oil generation) is included in the analog compaction profiles, and any additional mineral cementation following the onset of oil generation is negligible. Additional research is required to develop mudstone compaction curves for organic-rich rocks or sapropel sediments that may provide improved porosity predictions for the compaction of organic-rich (source rock) reservoirs. Currently it is difficult to separate the amount of amorphous and particulate organic matter that may have originated as kerogen from the void-filling organic matter by routine digital image analysis. This could lead to over estimating the amount of organic matter cement, and thereby organic matter porosity. New machine learning technology, such as described by Zhang et al. (2019), may offer the potential to develop improved methods to segment organic matter types into particles, matrix, and cement from digital SEM images.

Conclusions

The new proposed shale reservoir porosity prediction model is an attempt to improve the existing kerogen porosity models that are based on a conceptual model and empirical correlations that have yet to be rigorously tested. The pyrobitumen model is constrained by detailed SEM petrographic observations that identify organic matter porosity within void-filling organic matter, or organic matter cement. The organic matter cement is interpreted as a thermally altered residue (pyrobitumen) derived from residual oil and solid bitumen within mineral matrix pores at elevated thermal maturity (>1.0%Ro). The primary control on
the amount and distribution of organic matter porosity is a function of the available mineral matrix porosity preserved at the onset of oil generation, and level of thermal maturity. This is a significant departure from previous organic porosity prediction methods that assume pores are developed within kerogen as a function of the volume of oil generated during thermal degradation of labile kerogen.

Although further calibration and validation is required, this new model provides useful insights to the process and controls of the diagenetic evolution of organic matter and organic porosity development. Hopefully, this research will inspire further studies that could positively impact future exploration and development strategies for shale hydrocarbon reservoirs.

![Figure 1](image)

**Figure 1.** The maximum amount of potential organic matter cement is predicted by estimating the porosity preserved following compaction at the depth corresponding with the onset of oil generation.

References


