**Geologic and petrophysical characterization of source rocks and shale-gas reservoirs**

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Many currently producing shale-gas reservoirs are overmature oil-prone source rocks containing Type I or Type II kerogen. Key characterization parameters are: total organic carbon (TOC), maturity level (vitrinite reflectance), mineralogy, thickness, and organic matter type (OMT). Recent studies indicate that although organic-rich shale-gas formations may be hundreds of meters in gross thickness (and may appear largely homogeneous), the vertical variability in the organic richness and mineralogy can vary on relatively short vertical scales (e.g. 10's cm - 1 meter). The vertical heterogeneity observed can be directly tied back to geologic and biotic conditions when deposited. The accumulation of organic-rich rocks (ORRs) is a complex function of many interacting processes that can be summarized by three main control variables: rate of production, rate of destruction, and rate of dilution. The marine realm includes three physiographic settings that accumulate significant organic-matter-rich rocks: constructional shelf margin, platform/ramp, and continental slope/basin. In general, the fundamental geologic building block of shale-gas reservoirs is the parasequence, or its equivalent, and commonly 10's to 100's of parasequences comprise the organic-rich formation whose lateral continuity can be estimated using techniques and models developed for source rocks.

Many geochemical and petrophysical techniques developed to characterize organic-rich source rocks in the oil-generation window (Ro=0.5-1.0), can be applied, sometimes with modification, to shale-gas reservoirs that currently exhibit high thermal maturity (Ro=1.1 - 4.0). Typical sample analytical techniques include: total organic carbon (TOC), X-ray diffraction (XRD), adsorbed gas analysis, vitrinite reflectance (Ro), porosity, permeability, fluid saturation, detailed core description, thin section petrography, and electron microscopy. SEM images of ion-beam-milled samples reveal a separate nano-porosity system contained within the organic matter, possibly comprising ~50% of the total porosity, and 3D serial sectioning indicates that many of these organic pores are interconnected.

Well logs can be used to calculate TOC, porosity, and hydrocarbon saturation, but the nature of the porosity appears to be different from conventional sandstone reservoirs, and much of the gas appears to be associated with the organic-rich intervals. The use of high-resolution standard logs and borehole image logs enhances the interpretation of vertically heterogenous shale-gas formations. It is important to keep in mind that kerogen occupies a much larger volume percent (vol%) than is indicated by the TOC weight percent (wt%); this is because of the low grain density of the organic matter (typically 1.1-1.4 g/cc) compared to that of common rock-forming minerals (2.6-2.8 g/cc).

Porosity, permeability, and fluid saturation determinations of mudstone samples are challenging due to the very small particles and pores within the rock matrix, and this is further compounded by the occurrence of connected nanometer-scale pores within the organic matter. Comparison of vendor laboratory measurements of these basic rock and fluid parameters in mudstone samples indicates systematic and sometimes significant differences between laboratories. Moreover, in clay-rich mudstones, the fundamental definition of porosity is complicated by the high surface area of clay minerals (external and sometimes internal), the volume of surface water, and the presence of water held by capillary forces in very small pores between silt and clay size mineral grains.