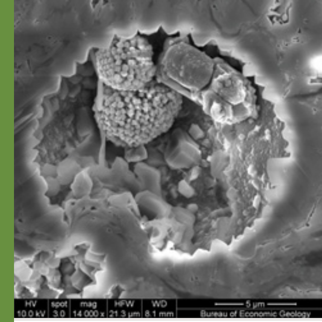
From Source Rock to Reservoir: The Evolution of Self-Sourced Unconventional Resource Plays



An example of intragranular porosity in the Eagle Ford Formation, south Texas

L. Taras Bryndzia* and Neil R. Braunsdorf*

1811-5209/14/0010-271$2.50 DOI: 10.2113/gselements.10.4.271

From a geological perspective, the exploration of shale source rocks is relatively straightforward. Advances in stimulation technologies, such as hydraulic fracturing, have made it possible to economically extract hydrocarbons, both liquid and gas, from their respective source rocks. However, the devil is in the details when it comes to "sweet spotting" which shale reservoirs are going to be the best producers. Organic-rich shales are fine grained and tend to be petrophysically challenging and mineralogically and geochemically heterogeneous on the nanoscale. The advent of focused ion beam – scanning electron microscopic (FIB-SEM) techniques now allows us to image the pore networks in the organic matter that generated the hydrocarbons we produce. Two types of pore networks exist in organic-rich shales. One type is water wetting and is associated with the inorganic component of the shale, mostly clays. The other pore network is hydrocarbon wetting and is associated with the porosity that develops in organic matter during maturation and hydrocarbon generation.

Keywords: source rocks, mudrocks, shale gas, unconventional reservoirs, total organic carbon

In this paper, we review (1) the basic concepts of hydrocarbon source rock formation, (2) the preservation of organic matter, and (3) the generation of hydrocarbons as a result of thermal maturation. We briefly discuss the mineralogical and geochemical characteristics exhibited by organic-rich source rocks, mostly from established North American plays. We also discuss how source rock porosity evolves with thermal maturity and how the evolution of organic matter (OM) porosity is key for the storage capacity of shale source rocks. Finally, we introduce the geochemical aspects of the role of water used in hydraulic fracturing and the consequences of its interactions with the inorganic shale matrix.

INTRODUCTION

Due primarily to the rapid development of unconventional hydrocarbon resources, North America is currently experiencing unprecedented growth in its domestic energy-resource base. This new production is attributable to recent advances in hydraulic fracturing technologies that enable both gas and liquid hydrocarbons to be produced directly from their respective source rocks. Conversely, conventional reservoirs contain hydrocarbons that have migrated from their source rocks, often over considerable distances, and were structurally and/or stratigraphically trapped. Conventional reservoirs usually occur in rocks that have favorable reservoir qualities such as high porosity and permeability, so that drainage is the primary mechanism by which hydrocarbons are initially recovered.

Because of their fine-grained nature, shale source rocks have low porosities and vanishingly low permeabilities, on the order of nanodarcies (Javadpour 2009; Sondergeld et al. 2010a, b). Matrix permeability, together with the viscosity of the reservoir fluid, controls hydrocarbon mobility and production efficiency (Bohacs et al. 2013). Economic production of hydrocarbons from unconventional shale source rocks is only possible if the rocks are stimulated by hydraulic fracturing in order to enhance the overall permeability and its connectivity to the wellbore.

WHAT IS A SOURCE ROCK?

A defining characteristic of a source rock is that it is rich in organic material that has survived deposition, varying degrees of biodegradation/bioturbation/oxidation, burial, diagenesis, and subsequent tectonism (Horsfield and Rullkotter 1994). The most abundant type of OM found in crustal sedimentary rocks is kerogen, a fossilized macromolecular insoluble form of OM (Vandenbroucke and Largeau 2007). Organic-rich source rocks include fine-grained sediments deposited both in marine and continental lacustrine environments, with a spectrum of source rocks representing variable contributions of organic matter and clastic sedimentary input. The depositional environment controls the primary type of OM that is formed (Tissot and Welte 1984).

MINERALOGY OF SOURCE ROCK SHALE

Source rock shales display strong textural and compositional heterogeneity on a submillimeter scale (Fig. 1). They are composed essentially of clays, quartz, carbonate, and OM, with subordinate to minor amounts of feldspar, mica, pyrite, and sulfate minerals. Figure 1 shows the mineralogical and textural diversity observed in source rocks from three unconventional shale gas plays in the United States: the Cretaceous Eagle Ford Formation in southwest Texas, the Upper Jurassic Bossier and Haynesville shales from northwest Louisiana, and the Mississippian Barnett Shale from north Texas. The Eagle Ford Formation is not strictly a shale or mudstone. It is a marl, consisting of fossiliferous carbonate material (up to 90%) and a minor

* Rock Properties Characterization and Modeling Team
Shell International Exploration & Production Inc.
Houston, TX 77251-7171, USA
E-mail: Taras.Bryndzia@shell.com

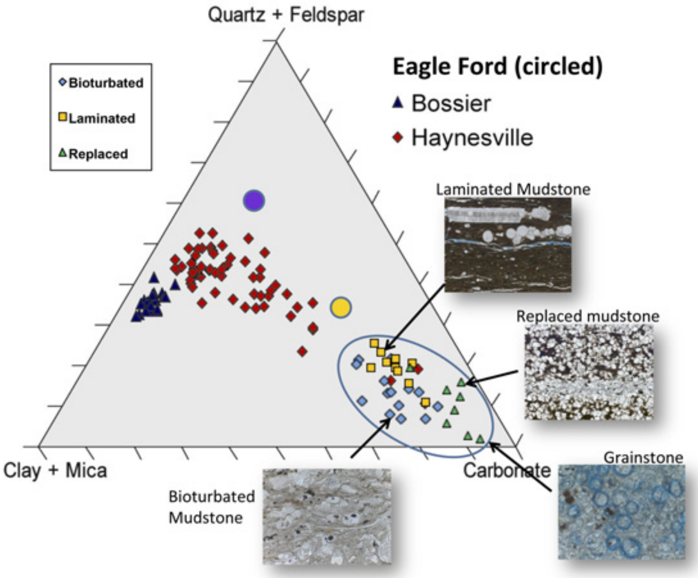


FIGURE 1 Ternary plot showing the range of mineralogical composition in shale source rocks from three major unconventional source rock plays in North America. Average Barnett shale (Texas, USA) compositions: purple circle = siliceous mudstone, gold circle = lime mudstone (Loucks and Ruppel 2007). Carbonate-rich rocks from the Eagle Ford Formation (Texas, USA) are marls (in oval), as described in the text.

fraction of biosiliceous radiolarian tests and sponge spicules (Ozkan et al. 2013). The Bossier and Haynesville shales contain much less carbonate material, with almost equal volumes of quartz and clay minerals, and variable carbonate content. By comparison, the Barnett Shale is unusually quartz rich due to its high content of biosiliceous silica (Loucks et al. 2009). Recrystallization of the amorphous silica during burial and diagenesis imparts a brittle character to the Barnett Shale that is highly desirable in hydraulic fracturing and enhances the producibility of source rock reservoirs (Buller et al. 2010). By contrast, the most silica-rich section of the Devonian Marcellus Formation (northern Appalachian Basin, USA) is the least brittle and also contains the highest volume fraction of total organic carbon (TOC) (Lash and Engelder 2011).

GEOCHEMISTRY AND PRESERVATION OF ORGANIC MATTER

Throughout geological time, there have been episodes of prolific organic productivity in the global oceans. One such example is the global Oceanic Anoxic Event, commonly referred to as OAE-2 (Schlanger and Jenkyns 1976). During this time of Earth history (ca 93.5 Ma), greenhouse climatic conditions prevailed, resulting in the deposition of some of the richest organic-rich source rock sediments on the planet. One example is the Eagle Ford Formation (Driskill et al. 2012; Macaulay et al. 2013).

Once deposited, OM is readily degraded and lost in oxic environments, either through digestion and bioturbation by bottom-dwelling organisms or through oxidation. Preservation of primary OM is enhanced in low-oxygen environments where reducing conditions prevail. It is the preservation of OM through geological time that defines the best unconventional shale source rock reservoirs. Evidence for anoxic conditions may be inferred from the trace element geochemistry of organic-rich source rocks, particularly uranium, vanadium, and molybdenum. Uranium content is commonly associated with high levels of OM. Due to its reduced solubility at low Eh, it is a good proxy for reducing conditions related to the deposition and preservation of OM (Partin et al. 2013). For example, the Lower Eagle Ford Formation contains higher uranium concentrations than does the Upper Eagle Ford (FIG. 2). The heavily bioturbated Upper Eagle Ford contains on

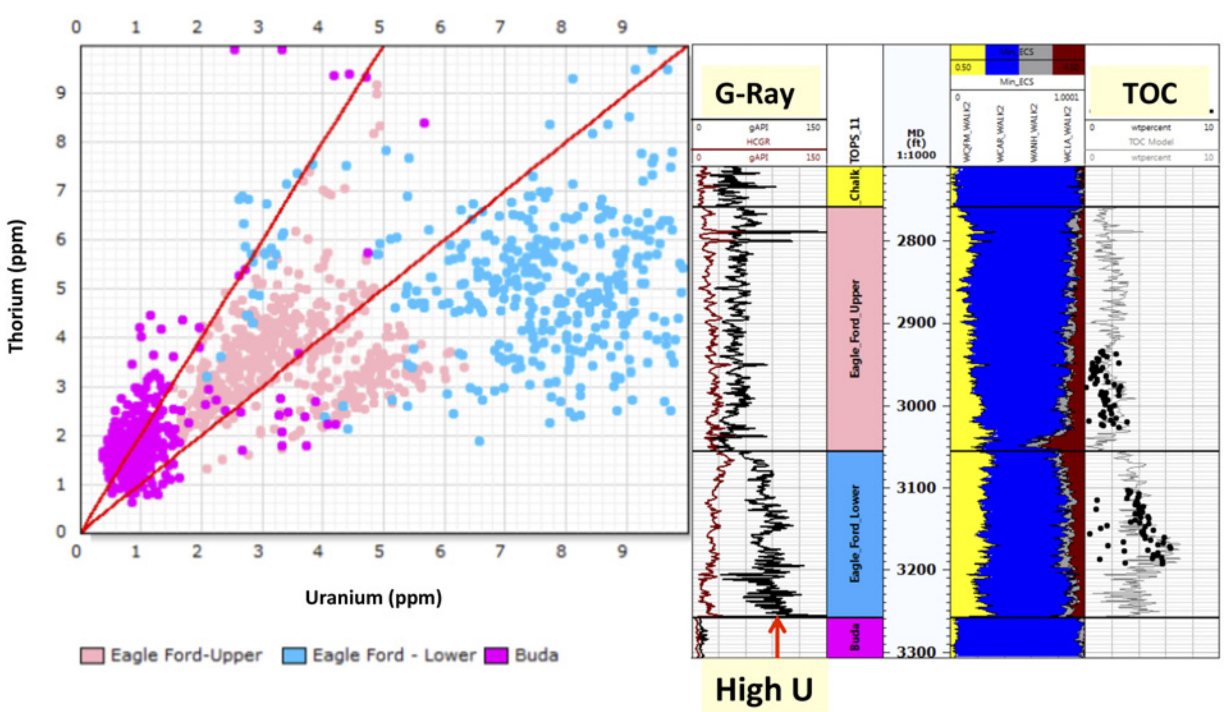
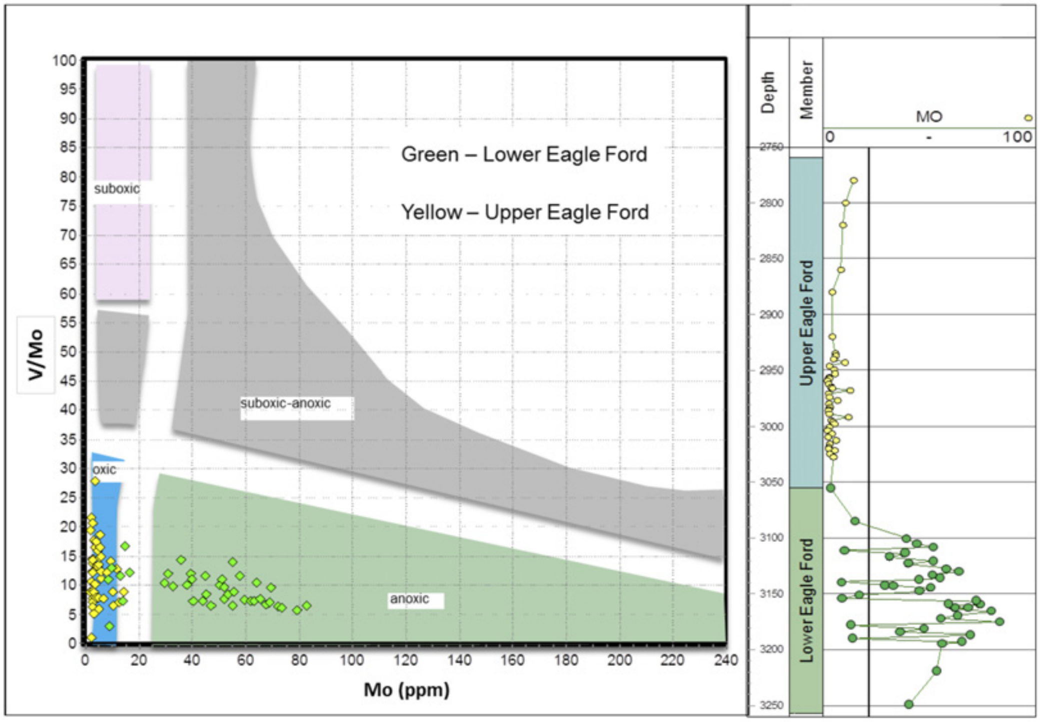


FIGURE 2 Thorium versus uranium plot for the Eagle Ford Formation in Texas, USA (left). Red lines separate fields of organic-rich Lower Eagle Ford from organic-lean Upper Eagle Ford and Buda limestone. Consistent with the data in FIGURE 3, the organic-rich Lower Eagle Ford Formation (blue) is readily distinguished from the lean Upper Eagle Ford Formation (pink) by its high uranium content and by its gamma-ray log response (black curve, central panel). The right panel shows a mineral log: yellow = quartz, blue = carbonate, brown = clay, and grey = sulfur-bearing minerals dominated by pyrite. Depth is in feet.

Figure 3 Paleoredox plot of the V/Mo ratio versus molybdenum content for the Eagle Ford Formation (Texas, USA). The Lower Eagle Ford samples have a V/Mo ratio approaching that of seawater, indicating anoxic depositional environments. The Upper Eagle Ford has both low molybdenum values (ppm level) and V/Mo ratios, indicating more oxic conditions at the time of deposition. Several Lower Eagle Ford samples have a relatively low V/Mo ratio, indicating more oxic conditions. The stratigraphic distribution of the samples using a 20 ppm Mo cut-off for anoxic sediments is displayed on the right (after Piper and Calvert 2009). Depth is in feet.



average 2 wt% TOC while the Lower Eagle Ford contains on average 6 wt% TOC. Vanadium and molybdenum are also good indicators of anoxia and are associated with the preservation of primary OM (Fig. 3).

MATURATION OF ORGANIC MATTER

When buried, organic-rich sediments undergo compaction and dewatering during which the OM undergoes thermal maturation, resulting in the cracking of kerogen macerals to produce a range of hydrocarbon products (Fig. 4). A relative measure of thermal maturity is the vitrinite reflectance (VRo). VRo is a measure of the percent of incident light of a given wavelength reflected off the surface of a polished sample of vitrinite (one of the main components of coal). It is measured under oil and commonly reported as % Ro. The original scale for VRo measurements was based on the level of metamorphism determined on coals, i.e. vitrinite (Hood et al. 1975). Establishing the level of thermal maturity in source rocks with vitrinite macerals is relatively straightforward. In marine source rocks, however, the amount of vitrinite is commonly quite low, particularly for rocks older than the Upper Devonian, when land plants developed. Therefore, for older marine source rocks, establishing reliable estimates of thermal maturity

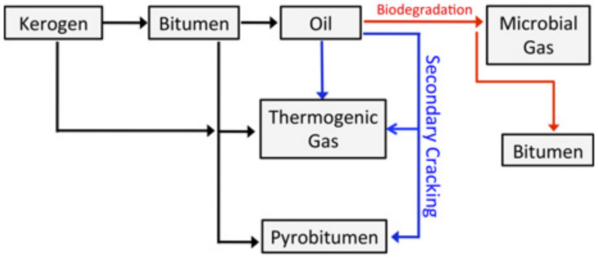


Figure 4 Schematic representation of kerogen conversion to hydrocarbon products, including thermogenic oil, thermogenic gas, and secondary products such as pyrobitumen formed by oil to gas cracking. Blue arrows represent secondary cracking of oil to thermogenic gas and/or pyrobitumen. Red arrows represent microbial degradation of primary oil to microbial gas and bitumen. After Jarvie et al. (2007)

becomes more challenging, and for rocks that contain no vitrinite at all, proxies for thermal maturity are based on fossil material such as spores and graptolites (Stasiuk 1994). In overmature source rocks, such as the Haynesville and Marcellus gas shales, very little vitrinite remains in the rock, particularly at high levels of thermal maturity where all liquid hydrocarbons are cracked to solid OM such as pyrobitumen. This thermal cracking of liquid hydrocarbons is commonly referred to as oil to gas cracking (OTGC). The type of OM remaining in a rock is a function of source rock type, reflecting marine (algal or benthic) or terrestrial (coal or plant debris) origin.

At low levels of thermal maturity, bituminous material is generated and subsequently converted to low-maturity black oil. With progressive increase in pressure and temperature during burial, hydrocarbon products become more gas rich and transition progressively from black oil through wet gas and retrograde gas condensate, and at the highest levels of thermal maturity, to dry gas dominated by methane. Expulsion and retention are clearly competing processes during the generation of hydrocarbons in a source rock. The lack of migration potential of hydrocarbons out of source rock shale is what ultimately defines an economic unconventional resource play. Figure 5 shows the areal distribution of hydrocarbons produced in the Eagle Ford shale/marl. The distribution of hydrocarbon types shows a maturity sequence increasing from the northwest to the southeast, progressing from low-pressure black oil to high-pressure oil and then to a gas-rich condensate liquid and to dry gas dominated by methane in the south.

POROSITY DEVELOPMENT AND STORAGE CAPACITY

Porosity development in OM increases as a function of thermal maturity due to the progressive generation of hydrocarbons (Fig. 6). Due to low permeability, not all of the liquid hydrocarbons are able to migrate out of the source rock. At higher temperatures, liquid hydrocarbons may be cracked to gas in oil to gas cracking (Fig. 4; Stasiuk 1997). Many studies have documented the development of porosity with progressive maturation of OM in organic-rich

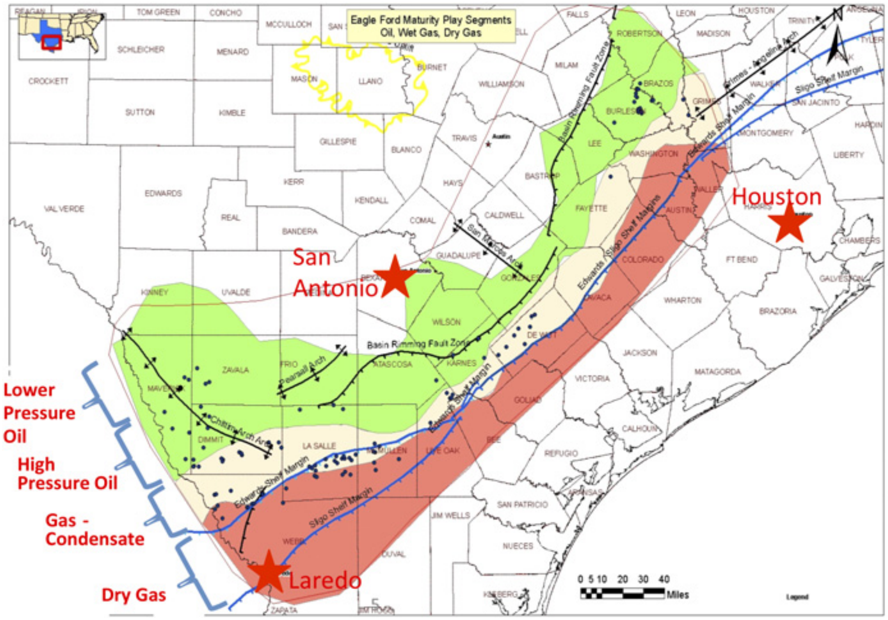


Figure 5 Areal distribution of hydrocarbons in the Eagle Ford shale play (Texas, USA). Maturity in this play increases from the northwest to the southeast and spans a belt of low- to high-pressure black oil (green), retrograde gas condensate (wet gas; pink), and at the highest levels of thermal maturity, dry gas (red) dominated by methane. Stars represent the cities of Houston, San Antonio, and Laredo.

source rocks (e.g. Milliken et al. 2012). In low-maturity source rocks, OM porosity is minor and difficult to detect, even using modern imaging techniques such as FIB-SEM methods. With progressive maturation and hydrocarbon generation, OM porosity becomes more obvious. Porosity is recognized as a significant contributor to both hydrocarbon storage capacity in source rock reservoirs and for providing pathways for hydrocarbon transport from the hydrocarbon wetting phases in the shale matrix, to the hydraulic fracture face, and ultimately to the wellbore (Wang 2009). Figure 6 shows examples of porosity development in OM from the Eagle Ford Formation and an example of pyrobitumen from the Bossier shale formed by OTGC at a Ro of ~2.5%.

Relationship between TOC and Porosity

The relationship between TOC, porosity, and storage capacity in organic-rich source rocks is not simply a function of maturity (Fig. 7). Moreover, the fact that organic-rich shale may contain a high TOC content is no guarantee that it will also have adequate storage capacity for hydrocarbons. As seen in Figure 7, despite relatively high thermal maturities (e.g. Woodford Formation with Ro of ~2 to 3%), most of the high-TOC shales show little to no porosity.

Dual-Porosity Networks

Imbibition experiments with dodecane and water established the presence of two different porosity networks in organic-rich shales (Odusina et al. 2011). One porosity system is water wetting, where water is imbibed either via osmosis and diffusion processes or capillary action (Bryndzia 2012; Engelder 2012). The other porosity network is oil wetting and is associated with OM in the shale. This network is best characterized via imbibition with an organic solvent such as dodecane. The different pore networks may also be characterized using nuclear magnetic resonance techniques (Odusina et al. 2011).

PROPERTIES OF UNCONVENTIONAL SOURCE ROCK RESERVOIRS

Capillary forces are high in fine-grained, clay-rich rocks, and permeability is typically low, such that hydrocarbons cannot readily escape from the matrix. Due to the generation of hydrocarbons, particularly gas, shale source rocks are also able to generate and retain high pore pressures.

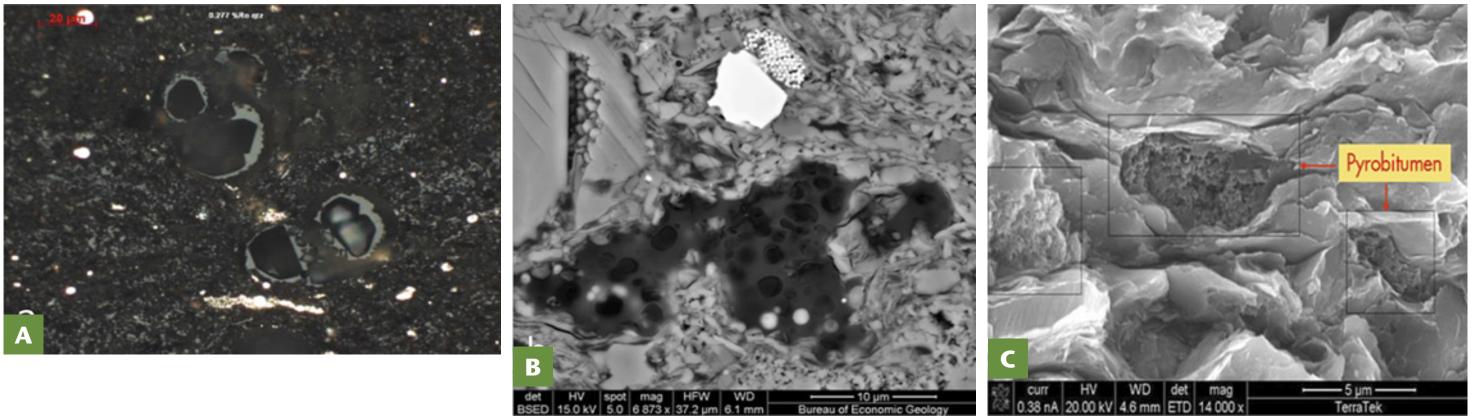


Figure 6 Examples of porosity development in organic matter within source rocks. (**A**) Coccoliths from the Eagle Ford Formation (Texas, USA) containing bitumen in which there is no visible porosity development (Ro 0.3%). Red bar in (A) is 20 µm. (**B**) Start of porosity development in OM from a more mature (Ro 0.65%) example of the Eagle Ford Formation. (**C**) Spongiform texture formed in pyrobitumen from the Bossier Formation (Louisiana, USA). The maturity of this sample is ~2.5% Ro and shows the enhanced storage capacity that can develop in OM in overmature shale source rocks as a result of oil to gas cracking. Compare with OM porosity in (B), which corresponds to a maturity of ~0.65% Ro.

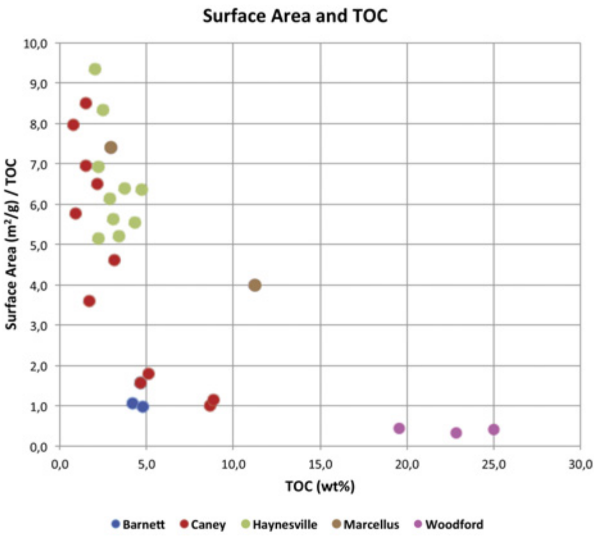


FIGURE 7 Total organic carbon (TOC)–normalized surface area of organic-rich gas-bearing shale from several established shale gas plays in North America. The total surface area accessible to N_2 gas is a proxy for porosity and an indicator of the potential storage capacity for gas in these shales. The data are from Valenza et al. (2013).

For example, the Haynesville gas shale and Marcellus shale have fluid pressure gradients that are estimated to be on the order of ~0.9 and ~0.85 psi/ft, respectively (Engelder et al. 2014). When appropriately stimulated, such high pore pressures contribute to the economic rates of production of source rock reservoirs (Wan et al. 2013). Where source rock reservoirs are breached due to tectonic activity and faulting, as in the case of the Marcellus shale, thermogenic gas may actually seep to the surface (Etiope et al. 2013). In such cases, loss of gas from the shale formation may result in a risk to production due to loss of gas pressure.

As a result of deposition, compaction, diagenesis, and recrystallization of clay minerals (e.g. diagenesis of smectite to illite), organic-rich shales develop intrinsic layering and display vertically transverse isotropy. This results in strong anisotropy in both horizontal and vertical elastic and mechanical rock properties (Lucier et al. 2011). Together with anisotropic rock properties, the orientation of the contemporary tectonic stresses has significant bearing on the distribution of minimum horizontal stresses in the subsurface. This impacts the planning and design of hydraulic fracturing programs because horizontal wells are drilled at right angles to the maximum horizontal stress (S_{Hmax}), and hydraulic fractures propagate along the minimum horizontal stress orientation (S_{Hmin}) (Higgins et al. (2008).

Late-stage OTGC generates prodigious volumes of methane, resulting in high gas saturation of the shale source rock and the formation of a solid carbon residue, commonly referred to as char or pyrobitumen (Stasiuk 1997). Expulsion and migration of large volumes of dry gas also removes most of the mobile water in the source rock shale. Because of the membrane-filtration capacity of very fine-grained, clay-rich, low-permeability rocks such as shales, relatively fresh, low-salinity water is expelled during compaction and kerogen maturation. This results in high concentrations of water-soluble ionic components remaining in the shale matrix. Most of the solute load and any residual water remaining in the inorganic shale matrix probably exist as complexes associated with clay mineral surfaces (Bryndzia 2012).

FUTURE CONSIDERATIONS

Common consequences of hydrocarbon generation in source rocks include:

1. High gas saturations with little to no mobile water,
2. Development of fluid pressures in excess of hydrostatic (i.e. overpressures), and
3. Unusually high concentrations of ions associated with clay mineral surfaces.

An organic-rich source rock having attributes (1) and (2) is an attractive target for unconventional hydrocarbon development. However, attribute (3) is more problematic. When gas shale is subject to hydraulic fracture stimulation using fresh water, the water undergoes rapid exchange with the shale matrix as a result of a coupled osmosis–diffusion process, resulting in flowback waters that have unusually high salinities (Blauch et al. 2009; Gregory et al. 2011; Bryndzia 2012). Due to imbibition, only a small fraction (10 to 20%) of the water used in hydraulic fracture stimulation is ever recovered (Bryndzia 2012; Striolo et al. 2012; Engelder et al. 2014). The availability, treatment, and disposal of this water represent a nontechnical risk to the sustainable development and economic viability of some unconventional source rock resource plays. The sustainable use of limited water supply in the exploitation of unconventional resource plays is also the focus of ongoing research, both within major exploration and production companies as well as in academia and regulatory agencies (Striolo et al. 2012; Bunger et al. 2013).

ACKNOWLEDGMENTS

We owe a debt of gratitude to many Shell colleagues, particularly Calum Macaulay, Amie Hows, Anton Nikitin, Aysen Ozkan, Ruarri Day-Stirrat, and James Eldrett for sharing data and figures, and for their insightful comments on earlier versions of this paper. This contribution also benefited from thoughtful reviews and helpful comments by Terry Engelder and Giuseppe Etiope. We gratefully acknowledge Shell management for permission to publish this paper. We also acknowledge colleagues at the Bureau of Economic Geology, University of Texas at Austin, for some of the SEM images obtained jointly through SUTUR, a Shell sponsored EMR project with UT and BEG.

REFERENCES

Blauch ME, Myers RR, Moore T, Lipinski BA, Houston NA (2009) Marcellus shale post-frac flowback waters – Where is all the salt coming from and what are the implications? SPE Eastern Regional Meeting, SPE 125740-2009

Bohacs KM, Passey QR, Rudnicki M, Esch WL, Lazar OR (2013) The spectrum of fine-grained reservoirs from 'shale gas' to 'shale oil'/tight liquids: Essential attributes, key controls, practical characterization. International Petroleum Technology Conference, Beijing, China, 26–28 March 2013, Document IPTC-16676

Bryndzia LT (2012) Origin of high salinities in hydraulic fracture flow back fluids - an example from the Haynesville shale gas play, USA. 3rd EAGE Shale Workshop, Barcelona, Spain, 25 January 2012

Buller D, Hughes SN, Market J, Petre JE, Spain DR, Odumosu T (2010) Petrophysical evaluation for enhancing hydraulic stimulation in horizontal shale gas wells. SPE Annual Technical Conference and Exhibition, Florence, Italy, 19–22 September 2010, Document SPE-132900-MS

Bunger AP, McLennan J, Jeffrey R (eds) (2013) Effective and Sustainable Hydraulic Fracturing. InTech, doi: 10.5772/45724, 1072 pp

Driskill B, Suurmeyer N, Rilling-Hall S, Govert A, Garbowicz A (2012) Reservoir description of the subsurface Eagle Ford Formation, Maverick Basin area, South Texas, USA. EAGE Annual

Conference incorporating SPE Europec, Copenhagen, Denmark, 4–7 June, 2012. Document SPE 154528

Engelder JT (2012) Capillary tension and imbibition sequester frack fluid in Marcellus gas shale. Proceedings of the National Academy of Sciences 109: E3625, doi: 10.1073/pnas.1216133110

Engelder T, Cathles LM, Bryndzia LT (2014) The fate of residual treatment water in gas shale. Journal of Unconventional Oil and Gas Resources 7: 33-48

Etiope G, Drobniak A, Schimmelmann A (2013) Natural seepage of shale gas and the origin of "eternal flames" in the Northern Appalachian Basin, USA. Marine and Petroleum Geology 43: 178-186

Gregory KB, Vidic RD, Dzombak DA (2011). Water management challenges associated with the production of shale gas by hydraulic fracturing. Elements 7: 181-186

Higgins S, Goodwin S, Donald A, Bratton T, Tracy G (2008) Anisotropic stress models improve completion design in the Baxter shale. SPE Annual Technical Conference and Exhibition, Denver, CO, 21–24 September 2008, SPE 115736, 10 pp

Hood A, Gutjahr CCM, Heacock RL (1975) Organic metamorphism and the generation of petroleum. AAPG Bulletin 59: 986-996

Horsfield B, Rullkotter J (1994) Diagenesis, catagenesis, and metagenesis of organic matter. In: Magoon LB, Dow WG (eds) The Petroleum System – From Source to Trap. AAPG Memoir 60, pp 189-199

Jarvie DM, Hill RJ, Ruble TE, Pollastro RM (2007) Unconventional shale-gas systems: The Mississippian Barnett Shale of north-central Texas as one model for thermogenic shale-gas assessment. AAPG Bulletin 91: 475-499

Javadpour F (2009) Nanopores and apparent permeability of gas flow in mudrocks (shales and siltstone). Journal of Canadian Petroleum Technology 48(8): 16-21

Lash GG, Engelder T (2011) Thickness trends and sequence stratigraphy of the Middle Devonian Marcellus Formation, Appalachian Basin: Implications for Acadian foreland basin evolution. AAPG Bulletin 95: 61-103

Loucks RG, Ruppel SC (2007) Mississippian Barnett Shale: Lithofacies and depositional setting of a deep-water shale-gas succession in the Fort Worth Basin, Texas. AAPG Bulletin 91: 579-601

Loucks RG, Reed RM, Ruppel SC, Jarvie DM (2009) Morphology, genesis, and distribution of nanometer-scale pores in siliceous mudstones of the Mississippian Barnett Shale. Journal of Sedimentary Research 79: 848-861

Lucier AM, Hofmann R, Bryndzia LT (2011) Evaluation of variable gas saturation on acoustic log data from the Haynesville shale gas play, NW Louisiana, USA. The Leading Edge 30: 300-311

Macaulay C and 7 coauthors (2013) Multi-scale characterization of the Eagle Ford (Boquillas) Formation of southwest Texas. Applied Geosciences Conference, Houston, Texas, USA, 18–19 February 2013

Milliken KL, Rudnicki MD, Awwiller DN (2012) Form and distribution of organic matter–hosted pores, Marcellus Formation (Devonian), Pennsylvania, USA. 3rd EAGE Shale Workshop, Barcelona, Spain, 25 January 2012

Odusina EO, Sondergeld CH, Rai CS (2011) NMR study of shale wettability. Canadian Unconventional Resources Conference, 15–17 November, Alberta, Canada. Society of Petroleum Engineers, doi: 10.2118/147371-MS

Ozkan A and 7 coauthors (2013) Influence of primary rock texture, diagenesis and thermal maturity on Eagle Ford pore systems. AAPG Annual Convention, Pittsburgh, Article 90163

Partin CA and 12 coauthors (2013) Large-scale fluctuations in Precambrian atmospheric and oceanic oxygen levels from the record of U in shales. Earth and Planetary Science Letters 369-370: 284-293

Piper DZ, Calvert SE (2009) A marine biogeochemical perspective on black shale deposition. Earth-Science Reviews 95: 63-96

Schlanger SO, Jenkyns HC (1976) Cretaceous oceanic anoxic events: causes and consequences. Geologie en Mijnbouw 55: 179-184

Sondergeld CH, Ambrose RJ, Rai CS, Moncrieff J (2010a) Micro-structural studies of gas shales. SPE Unconventional Gas Conference, Pittsburgh, Pennsylvania, USA, 23–25 February 2010. Document SPE-131771

Sondergeld CH, Newsham KE, Comisky JT, Rice MC (2010b) Petrophysical considerations in evaluating and producing shale gas resources. SPE Unconventional Gas Conference, Pittsburgh, Pennsylvannia, USA, 23–25 February 2010. Document SPE 131768

Stasiuk LD (1994) Fluorescence properties of Paleozoic oil-prone alginite in relation to hydrocarbon generation, Williston Basin, Saskatchewan, Canada. Marine and Petroleum Geology 11: 219-231

Stasiuk LD (1997) The origin of pyrobitumens in upper Devonian Leduc formation gas reservoirs, Alberta, Canada: an optical and EDS study of oil to gas transformation. Marine and Petroleum Geology 14: 915-929

Striolo A, Klaessig F, Cole DR, Wilcox J, Chase GG, Sondergeld CH, Pasquali M (2012) Identification of fundamental interfacial and transport phenomena for the sustainable deployment of hydraulic shale fracturing – role of chemicals used, 2012. Workshop Report, NSF Grant Number CBET-1229931

Tissot BP, Welte DH (1984) Petroleum Formation and Occurrences. Springer and Verlag, Second Edition, 699 pp

Valenza JJ III, Drenzek N, Marques F, Pagels M, Mastalerz M (2013) Geochemical controls on shale microstructure. Geology 41: 611-614

Vandenbroucke M, Largeau C (2007) Kerogen origin, evolution and structure. Organic Geochemistry 38: 719-833

Wan J, Barnum RS, DiGloria DC, Leahy-Dios A, Missman R, Hemphill J (2013) Factors controlling recovery in liquids rich unconventional systems. International Petroleum Technology Conference, Beijing, China, 26–28 March 2013. Document IPTC 17103

Wang F (2009) A new look at gas shales—why do they produce so well? 8th Annual Gas Shales Summit, 30–31 March 2009, Dallas, Texas