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Industry Players Still Have Much To Learn About Exploiting Shales

By Marlan W. Downey, Julie A. Garvin and Alex E. Downey

HOUSTON–Through most of its history, the petroleum business focused on oil and gas that had migrated into porous, conventional reservoirs. Now, companies need to refocus toward the peculiar properties of unconventional reservoirs. In particular, they need to become more intimately familiar with source rocks for crude oil and natural gas.

These source rocks once provided oil and gas to nearby reservoirs, and still retain gas and oil within their matrices. These former source rocks can be called unconventional reservoirs because we have developed techniques to extract the gas and oil they contain. They exist everywhere the industry previously found oil and gas in conventional reservoirs.

There appears to be as much oil and gas still retained in source rock matrices as has been expelled and trapped in reservoirs worldwide! Preliminary work by Steven Holditch, Zhenzhen Dong and Duane McVay at Texas A&M University has provided a staggering estimate of 125 quadrillion cubic feet of gas in place worldwide from unconventional reservoirs, of which 58 quadrillion cubic feet is recoverable.

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FIGURE 1

Oil in Place from S1

Simplified Equation

$$\textit{Oil in place per 640 acre/ft} = 9{,}677.48 \times (S1_{AV})$$

Where:

$S1_{AV}$ = *Average S1 (mg/g) from Rock-Eval*

Assumes: 2.5 g/cc bulk density, 50º API oil gravity

Conventional techniques for estimating volumes of in-place hydrocarbons in porous rocks are not accurate for shale systems. Measuring the in-situ hydrocarbons in source rocks requires collecting cores followed by detailed analysis. As shown in Figure 1, Rock-Eval pyrolysis measurements of S1 on source rock cores can determine the volume of oil contained in the sample. Multiplying by the rock volume provides a measurement of oil in place.

Recognizing that suitably immense volumes of hydrocarbons are contained within source rocks, companies are concentrating their efforts toward more efficient extraction of oil and gas from those source rocks. We know we are extracting only a small percentage of the in-situ oil and gas in source rocks, and our production rates are barely acceptable.

Understanding Shale Reservoirs

To understand shale oil and shale gas (source rock) reservoirs, it is necessary to appreciate their unique and peculiar characteristics. They are not low-permeability variants of our well-known conventional reservoirs; source rock properties are not like those of conventional reservoirs.

Studies of conventional reservoirs are concerned largely with the amount and interconnections of the larger void spaces in the rock, and the proportions of water and hydrocarbons in those pore spaces. Void sizes in source rocks are many thousands of times smaller than in conventional reservoirs, and these tiny pores contain very little water.

Their peculiar rock properties arise from their muddy matrices, their large amount of compressible organic matter (10-35 percent by volume), and from the high-pressure hydrocarbon impregnation of tiny matrix pores as solid organic matter was liquefied and volatilized during burial.

Only a limited range of rock types are seen as source rocks. Typically, they are carbonates and clays deposited in lake or marine settings. The peculiar properties of all source rock reservoirs can be attributed mainly to their extraordinary volume of organic matter. All source rocks originate through the preservation of large quantities of organic matter that accumulated in oxygen-deficient sedimentary environments.

The rain of organic matter from overlying, oxygenated waters enters an oxygen-deficient "dead zone" on the sea floor, and undisturbed by burrowing organisms, provides layers of organic matter. The large amount of organic matter, the strongly reducing depositional environment, and the lack of bottom-churning organisms (the preservation of layering) leads to the very dark brown, pyritic, laminated character of typical organic-rich rocks.

During shallow burial, the organic matter (spores, pollen, algal matter and waxes), is still transparent and pale yellow by transmitted light, and is still recognizable as organic debris. If buried to greater depths (to greater temperatures), the organic matter will darken, will be "cooked" (matured), and eventually will decompose to oil, gas and carbon residue. As the thermally generated hydrocarbon liquid expands and floods the micropores of the sediment, the rock is said to be thermally mature, i.e., a source rock for petroleum hydrocarbons.

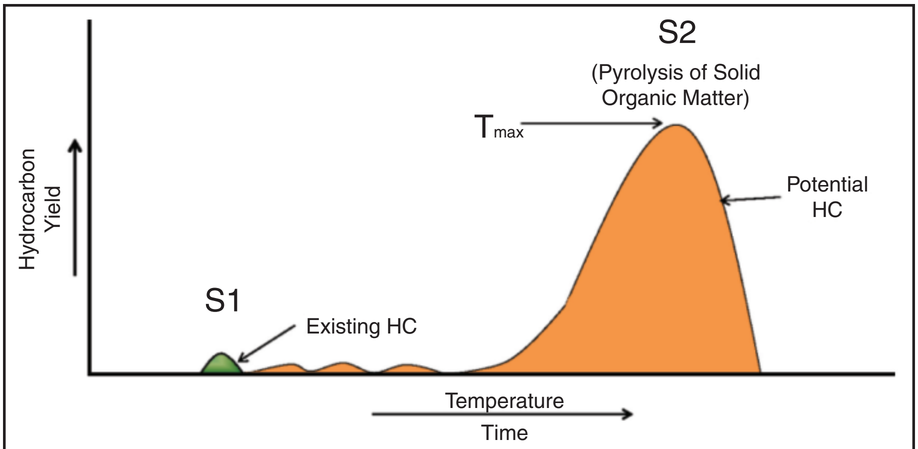
As the generated oil and gas saturates the solid organic matter, and injects oil into the micropores of the source rock, the rock becomes oil wet. In a 2001 American Association of Petroleum Geologists publication, F.F. Meissner and M.R. Thomasson called attention to the widespread change in resistivity of the Bakken Shale below a particular depth in the Williston Basin. They postulated that the resistivity change must be signaling that oil was generating and filling pore space. A generation later, exploitation technology has capitalized on Meissner's observation for the wildly successful Bakken oil play.

Organic Matrix

To best understand the peculiar rock and fluid properties of source-rock reservoirs, one needs to look internally at the organic matrix that is such an important part of the rock. We can make use of a particular sort of analysis that shows the changeable properties of the organic portion of the source rock reservoir.

FIGURE 2

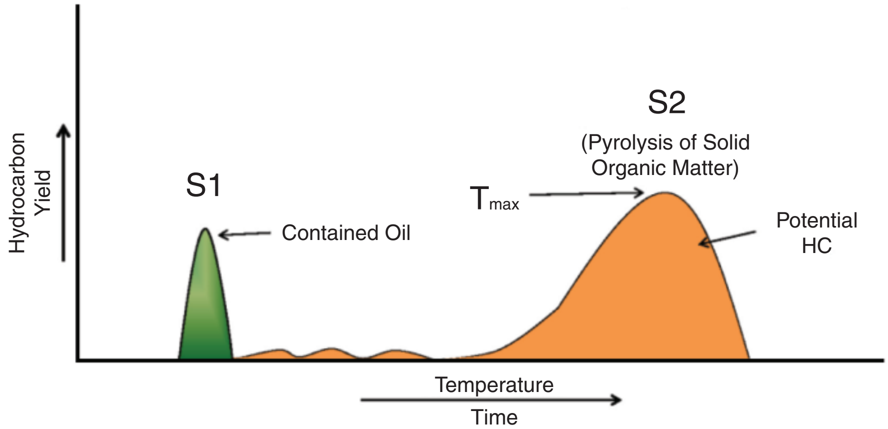
Typical Pyrolysis Profile for Immature Rock



The organic matter contained in an immature source rock has not been subjected to enough heat in the earth to convert its solid organic matter to oil.

FIGURE 3

Typical Pyrolysis Profile for Mature Rock



Oil is contained in the mature source rock.

The laboratory equipment (Rock-Eval) involves the programmed heating of a few grams of source rock sample, coupled to a flame ionization detector that records the weight percentage of hydrocarbon emitted from the rock sample at each stage of heating. Convention describes the low-temperature, first-volatilized product as the S1 peak; the broader, later peak represents the decomposition of the solid organic matter, and is referred to as the S2 peak.

Examining such data reveals how much oil is present in the rock, as well as the temperature history of the solid organic matter.

If one collected source rock samples at various depths (temperatures), and analyzed each sample with Rock-Eval, he could study the changes caused by burial and temperature of the solid organic matter in the rock, and in effect, observe the in-situ generation of oil. With even greater burial to higher temperature, the remaining solid organic matter will become a carbon sponge, becoming an unconventional gas reservoir itself.

With continued burial, the newly generated oil (S1) increases until it has saturated the solid organic matter (S2), and fills the micropores of the rock. With continued generation of oil, geopressured oil and gas are expelled from the source rock through microfractures, and may migrate by buoyancy to conventional porous reservoirs (Figures 2-4).

Enabling Technology

It is known that the oil and gas in all source rock reservoirs is contained within a low permeability matrix that allows only very slow migration of the oil and gas molecules. Natural permeability of the source rock reservoirs is four-five orders of magnitude less than that needed for commercial flow rates and exploiting conventional reservoirs.

In a source rock matrix, even methane molecules (the smallest of the hydrocarbons) can move laterally only a few feet a year. Movement of the larger oil molecules through the matrix is even slower. Commercial production of hydrocarbons from such low-permeability rocks has been limited fundamentally by the extremely low rate of hydrocarbon movement through the matrix microporosity to a producing bore hole.

Today's extraction technologies are based fundamentally on horizontal drilling to expose a maximum rock volume to treatment, and hydraulic fracturing to create an extensive network of high-permeability flow paths. The power of these tools can be easily understood if one looks at the amplifying effect of each technology for extracting oil and gas:

- A horizontal well drilled 5,000 feet laterally exposes 100 times as much reservoir to the well bore as does a 50-foot vertical penetration of the same reservoir.
- Gas moves through fractured source rock at rates of hundreds of feet a minute. It moves through unfractured source rock at rates of one to two feet a year. Oil moves even more slowly.

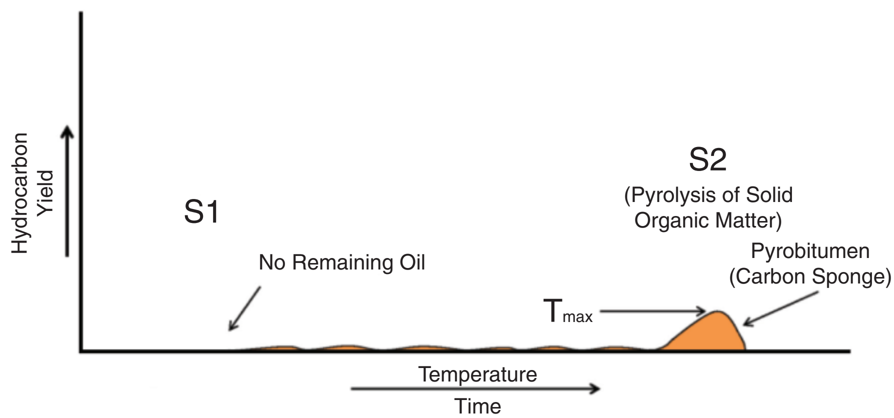
The role of horizontal drilling plus massive fracturing is to provide an extensive overprinting fracture network so that oil and gas molecules in the matrix have only a few feet to migrate before they enter the fractures, thereby providing rapid exit.

One can create a network of fractures in the source rocks through hydraulic fracturing. Early work by M.K. Hubbert and W.W. Rubey provided the fundamental underpinning for fracture development in the subsurface. Not only does theory predict that fracturing in the subsurface is normally near-vertical, it suggests that increased pore pressure makes a rock easier to fracture. As the areas around the fracture network are gradually depleted, one can expect the undrained areas (retaining near-original pressure) may become most susceptible to refracturing.

The fracture volume is most extensive

FIGURE 4

Over-Mature Source Rock with No Remaining Oil



A pyrobitumen "carbon sponge" residue is present in an over-mature source rock with no remaining oil.

when it is developed from a long horizontal bore hole. Increasing the length of the horizontal bore hole provides a linear increase in the fractured reservoir exposed to the bore hole.

Areas Of Ignorance

We know that ease and distribution of induced fracturing are controlled by matrix rock brittleness, ductility contrast, thickness of rock layers, pre-existing joint patterns, internal pore pressure, the hydraulic pressure of the injected water, and the contained proppants. The interplay of these factors has, thus far, been too complex to predict fracturing success without local trials.

We think we know that the specific source rock layer in which the horizontal well is drilled is important. But we have very scanty data available to demonstrate that, say, horizon B is 10, 50, or 100 percent better than horizon D in the same source rock. What data can be collected early to reliably point us to the “best” layer in a thick source rock, instead of drilling numerous lateral tests of various layers?

Another concern is the impact of hydraulic fracturing on the proppant used. Visualize proppant grains in a fracture plane between, for example, two 40-ton reservoir blocks subject to the fracturing vibration forces of a Richter II earthquake . . . multiple times. What size proppant resides in fractures after fracturing multiple stages? What happens to flow paths on flow back of fluids and proppant?

We think we know that inserting larger quantities of frac fluid and proppant provides more fracture area and higher flow back. Is the relationship truly linear and simple?

We have good data on where, and how much, proppant enters the formation. What we really want to know is which perforations actually are providing flow back, and how much. What cost-effective remedial approaches can we consider for perforations that do not yield flow back?

We have little idea of how a cluster of fractures we created changes its internal connectivity over time.

What is the decrease of flowing pressure in an undulating, cased horizontal bore hole? How can we minimize the factors that rob us of flow rate?

How does our estimate of hydrocarbon recovery volume compare with our estimates of the fracture-dominated drainage area?

We have a lot of room for improvement!

Consequences Of Shale

Exploiting source rock hydrocarbons is possible in every hydrocarbon-producing province. Mainly for logistical reasons, for the next decade, it will continue to be less expensive to produce oil and gas from these unconventional reservoirs in the United States and Canada than it will be to produce them internationally.

Producing domestic supplies of inexpensive energy provides a striking advantage to domestic energy users, and is sparking a resurgence of manufacturing that benefits American and Canadian companies. One of the largest elements of America’s balance of payments deficit–buying imported oil–is being eliminated.

At the state and local level, businesses and jobs are booming wherever shale oil and shale gas are being extracted, transported, and used. Notably, independent oil producers did it their way, without government grants.

Even with expected growth in population and energy demand, it now appears that the “hydrocarbon era” of inexpensive energy easily can be extended another 50-75 years, thanks to tar sands, ever more efficient use of energy, modest supplies of alternative energy, and most importantly, American innovations in extracting oil and gas from unconventional source rock reservoirs. ❒

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Marlan W. Downey is chairman of Roxanna Oil, which he founded in 1987. He previously has been president of Pecten International (Shell Oil), Arco International, and the American Association of Petroleum Geologists. He also has served as Bartell professor and chief scientist at the Sarkeys Energy Center at the University of Oklahoma. Downey received the Hedberg Medal and the Sydney Powers Medal, and has been recognized by the world’s largest geological society as a “Living Legend.”

JULIE A. GARVIN

Julie A. Garvin joined Roxanna Oil as president in 2005, after a 23-year career with Marathon Oil. During her tenure at Roxanna, she has been directly involved in generating and executing early entry positions into new and emerging resource plays for Roxanna’s clients and industry partners. Garvin holds an honor’s degree in geophysics from the University of Texas, and serves on the Jackson School of Geology Advisory Council.

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