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Assessing Well Performance in a Prolific Liquids-Rich Shale Play - An Eagle Ford Shale Case Study, Texas, U.S.A.

Doug Portis[1], Paul Clarke[1], Gervasio Barzola[1], and Hector Bello[1]

[1]Pioneer Natural Resources

Abstract

A series of subsurface reservoir and geologic properties are reviewed, specific to the Eagle Ford Shale of south Texas and compared with production trends. Currently, an area in excess of seven million acres has been tested for Eagle Ford production potential by hydraulically fracture-stimulated, horizontal wellbores. The bulk of this area is suitably thick (>125 ft [38 m]), organic-rich (>2 wt% TOC), and attains a thermal maturity consistent with hydrocarbon generation for Type-II kerogen (>435°C Tmax). Production trends, highlighted by well performance analysis from > 3,400 wells, point to a clear differentiation of an optimum fairway comprising a greater population of strong wells. Understanding well performance, and more importantly, key drivers that govern well performance provides motivation for this study.

The results of this study highlight the fact that best performing wells across the play (initial 18 month cumulative production) are located within a narrow seven mile wide, SW/NE strike orientated belt that extends across several counties spanning ~140 miles. This fairway in general parallels the ancestral Lower Cretaceous shelf edges (Sligo and Stuart City) and is characterized by a thermal maturity window (460-500°C Tmax) consistent with wet-gas and condensate production. Structurally downdip of these margins the play transitions into dry gas. Moving updip to the north, lower levels of thermal maturity are encountered that deliver lower volume wells, presumably due to lower levels of kerogen conversion and transformation. Thermal maturity is one of the primary well performance drivers in the play.

Across the central portion of the trend, within optimum maturity window, local production sweet-spots exist that are further delineated by a combination of higher reservoir pressure and interaction of local depositional patterns that promote above-average accumulations of organic-rich facies. By contrast, a significant proportion of poorer wells analyzed commonly display much higher values for clay content, even though many of these wells share favorable levels of thermal maturity, reservoir pressure, and moderate organic-richness. Clay content is the single most important metric that significantly degrades well performance, even when other parameters are favorable. Wellbore scale properties such as the occurrence of natural fractures appear to influence early time flow-back profiles, but have a modest influence on long-term well production.