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The impact of pressure and fluid property variation on well performance of liquid-rich Eagle Ford shale

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A B S T R A C T

The Eagle Ford Shale presents a unique opportunity to assess the effect of wide-ranging fluid properties and pressure on well performance across a single shale play. Thermal maturity, depth, and pressure vary significantly across the Eagle Ford. Reservoir and fluid property variations impact production performance and complicate decline analysis. In addition, operational decisions and facilities limitations further complicate analysis of well performance. Numerous case studies have focused on local parameters for production analysis, such as geometry and conductivity of hydraulic fractures. Few have addressed field-wide parameters like fluid properties and pressure variations.

In this paper, we outline the impact of variations in pressure and fluid properties on the key characteristics of production performance, such as initial rate, decline rate, gas-oil ratio (GOR), and recovery in two different regions of the Eagle Ford.

The following sources of information were used:

1. Geological and petrophysical evaluation: isopach, porosity, and water saturation were derived from log analysis and mapped across the Eagle Ford.
2. Reservoir fluid characterization: The field was divided into 12 regions on the basis of American Petroleum Institute (API) gravity. Gravity was mapped across the reservoir, and for each region a fluid model was built by matching pressure-volume-temperature data against an equation-of-state model.
3. Production data: Monthly production is available for all the wells. Two windows were selected to investigate the effect of changes in fluid properties and pressure on production performance; each window contains six wells. The east window is in Karnes County, Texas, and the west window covers Dimmit and Webb Counties, Texas. Both windows extend downdip from northwest to southeast, the direction of thermal maturity variation. A numerical model was built for each well and calibrated with production history.

We found that a high initial production rate and steep decline indicate an area of large fracture contact but low matrix permeability. In each fluid region, the difference between initial pressure and saturation pressure controls the GOR. The drainage area and recovery increase from oil-to gas-bearing regions. In the oil-bearing regions of Karnes County, expansion drive is the production mechanism; in Dimmit and Webb Counties, solution-gas drive is effective, along with expansion drive.

1. Problem statement

Different depositional environments and tectonic and structural events have given the Eagle Ford Shale a wide range of thermal maturity (Cardneaux, 2012). Thermal maturity not only changes the fluid type and the American Petroleum Institute (API) gravity but also affects the reservoir pressure distribution and petrophysical parameters like porosity and the presence of natural fractures.

The Eagle Ford dips from its northwestern outcrop to the southeastern boundary, giving a depth range for the effective reservoir that goes from 1500 to 14,000 ft. Different levels of total

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organic carbon (TOC) and thermal maturity (Honarpour et al., 2012) give the Eagle Ford a wide fluid composition range, from low gravity in updip Atascosa County (Billingsley et al., 2015) to volatile oil, gas condensate, and dry gas in downdip Webb County. Thermal maturity increases the porosity associated with kerogen by converting organic matter to hydrocarbons (Allan et al., 2013; Pommer et al., 2014). Generation of hydrocarbons within the shale accounts for part of the overpressure within the Eagle Ford Shale (Cander, 2012). This overpressurization increases toward the south, where greater maturation results in a pressure gradient of 0.9 psi/ft in the dry gas region. When the overpressured Eagle Ford was uplifted in the west (Cardneaux, 2012) pore pressure exceeded overburden pressure. Thus, pore pressure exceeded the fracture gradient, creating microfractures in the west Eagle Ford.

The wide range of reservoir properties results in different production performance. Production performance varies locally and broadly across the Eagle Ford. Many neighboring wells, despite having the same completion design, are producing at different rates (Billingsley et al., 2015). Local variations in well performance are due to rock heterogeneity and completion efficiencies (Gullickson et al., 2014). However, at larger scales, pressure and fluid composition—along with geology—dictate production behavior.

Several studies have related well performance and estimated ultimate recovery to operational and reservoir parameters (LaFollette et al., 2014; Swindell, 2012). Most of these works are based on statistical analysis of the impact of well architecture, completion, and stimulation parameters on production.

In addition, many case studies integrate drilling, completion, stimulation, fracture surveillance, and formation evaluation to address the well's performance (Hull et al., 2013; Cook et al., 2014; Hull et al., 2013; Ilk et al., 2012; Portis et al., 2013). All these studies are applied to a specific region. The focus of this paper is to find the key controls on the productivity of wells in the entire Eagle Ford play and to evaluate them. This study is part of a larger project to assess the Eagle Ford oil and gas resources (Browning et al., 2013a,b; Patzek et al., 2013).

In this larger project in-place resources are estimated, and future play-wide production rates are also modeled, under a variety of price, cost, and technology assumptions. The project required integrating all geological, petrophysical, fluid, and completion information. Data collected from well logs were used to create maps of geologic attributes affecting in-place resources and productivity of the Eagle Ford. The resulting maps represent the key Eagle Ford attributes such as mineralogical composition, TOC, porosity, thickness, and water saturation (Hammes et al., 2014). This work then integrates geological and petrophysical data to explain production behavior across the Eagle Ford. In what follows, we discuss the type of data that were collected and their sources. Then, the procedure for pressure mapping is explained. The Eagle Ford was divided into 12 fluid regions, and the physical properties of each fluid region were derived. Finally, the sensitivity of well performance to reservoir parameters was analyzed with reservoir simulation. We conclude with a discussion of key findings.

2. Data

Data for this study were collected from public and commercial sources. Wireline logs comprising gamma-ray, sonic, density, resistivity, neutron porosity, and density porosity were used to determine reservoir thickness, porosity, and water saturation (Hammes et al., 2014). Monthly production, specific gravity, and completion data are from a commercial database (IHS, 2014). Monthly production data include oil, water, and gas production after allocation for individual wells. Completion data include well stimulation parameters, such as the amount of water and proppant injected, the number of stages, and perforation intervals. Horizontal well lengths were calculated from well survey point data. The first instance where the vertical well angle relative to horizontal becomes less than 85° is where we define the beginning of the horizontal well length. These parameters are provided for 12,500 wells drilled in the Eagle Ford before March 2015. Quality control was performed to make sure data were reliable. In addition, 42 full pressure-volume-temperature (PVT) reports were obtained from the Texas Railroad Commission (RRC). PVT reports contain reservoir fluid composition and provide the results of constant composition expansion and constant volume depletion tests that were conducted on reservoir fluid samples. Some of the reports include an initial reservoir pressure and depth that can be used for generating the pressure map. Bottomhole temperature (BHT) for 3467 wells is available from log data. BHT (minus 60 °F surface temperature) was divided by depth to get the temperature gradient after the temperature was corrected for circulation time. The temperature gradient was multiplied by the depth of the top of the underlying Buda depth to obtain the Eagle Ford temperature.

2.1. Pressure

Pressure maps were generated using pressure data points obtained from PVT reports from the RRC. We obtained 42 pressure points in the narrow gas condensate region in De Witt, Karnes, Live Oak, and McMullen Counties (Fig. 1). The hydrostatic pressure gradient is 0.85 psi/ft in De Witt County and decreases toward the southwest, according to data in the PVT reports (Fig. 1). In addition to pressure data points, an understanding of geology and hydrocarbon generation was used to estimate the pressure field in the Eagle Ford. Overpressurization of the Eagle Ford is partly due to high thermal maturation and hydrocarbon generation. Therefore, pressure gradient increases downdip where maturation increases. In the north, thermal maturity is low. In addition, the Eagle Ford crops out in the north. Therefore, a normal hydrostatic pressure gradient was used for the northern boundary. In the southwest, a hydrostatic pressure gradient of 0.88 psi/ft was used because of the existence of lean gas, indicating high thermal maturity. Between the normal hydrostatic pressure gradient in the north and the 0.88-psi/ft pressure gradient in the south, pressure gradient contours were aligned with thermal maturity contours (Fig. 2). The hydrostatic pressure gradient was multiplied by the depth of the top of the Buda (base of Eagle Ford) to obtain the pressure map (Fig. 3).

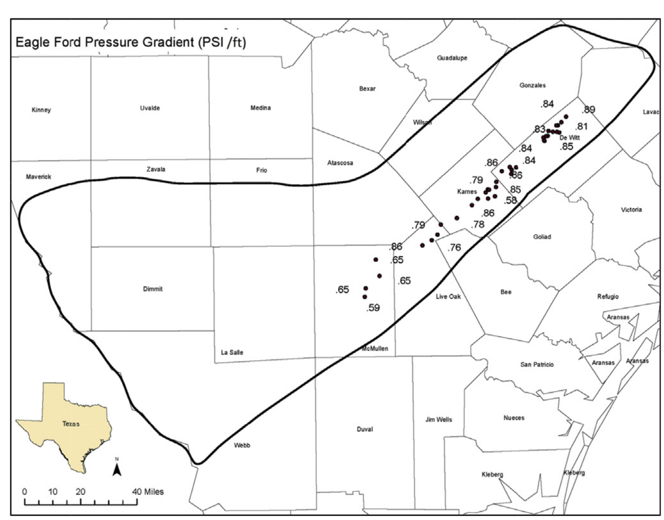

Fig. 1. Pressure gradients calculated from pressure and depth data in PVT reports.