An Analytic Approach to Sweetspot Mapping in the Eagle Ford Unconventional Play*

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Abstract

The Eagle Ford Shale in South Texas is one of the top producing, yet complex unconventional plays in North America. Well-to-well production variability confounds a "factory" approach to field development, as preferred by many operators. Greater insight into sweetspot locations and optimal drilling and completions parameters is required to drive enhanced well production. While the breadth of engineering, geology, and geophysics variables are daunting – modern analytic techniques provide a means to assimilate and comprehend massive amounts of disparate data.

In this study, over 3500 horizontal wells are modeled with non-linear analytics, to identify what geophysical and geologic properties define drilling sweetspots and what drilling and completions parameters drive better well production. Reservoir depth, related to pressure and thermal maturity; oil/gas mixture; thickness and proximity to faults are some of the major identified controls of Eagle Ford production sweetspots. Nominal well lengths of approximately 5500 feet with 25 fracture stages as some of the key drilling and completions parameters that correlate with optimal well production. Combining these results with current economics for oil, gas and liquids provides a unique perspective into targeting factory-based field development in unconventional plays.

Introduction

With over 250 active rigs and more than 3500 producing oil and gas wells, the Cretaceous Eagle Ford Shale in South Texas has rapidly emerged as one of the top North American unconventional plays. However, even with production exceeding 1 million barrels of oil equivalent per day (~70% liquids), individual well production is highly variable , indicating there is much left to understand about sweetspot high-grading and optimizing both well spacing and completions.

Covering an area of more than 11,000 square miles, the Eagle Ford is grossly a depth-driven petroleum resource: producing oil at depths of 5000-8000 feet to the northwest, grading through condensate and natural gas liquids, to dry gas at depths of 10,000-12,000 feet to the southeast. Initial production rates range from more than 6000 barrels per day of oil to over 20 mmcf of dry gas, across the dip trend.

In 2013, the expected industry capital expenditure in the Eagle Ford is expected to approach US $30 billion. Major Eagle Ford operators, with larger lease holdings, are currently taking a "factory" approach to development – laying out a systematic horizontal well pattern across prospective acreage. However, initial well production levels, which average roughly 1000 barrels of oil equivalent (BOE) per day, range to more than 6-times this rate in the best wells. Clearly, the Eagle Ford is not a simple resource; with sweetspot trends of geology, pressure and hydrocarbon mix, and other factors, defining preferred locations. However, even after 3500 wells, a comparison of drilling and completions "best practices" reflects a high degree of variability in: well length and orientation; number of fracture stages, and hydraulic fracturing volumes and rates.

Optimizing production in the Eagle Ford requires an understanding of both relative production sweetspot locations AND effectiveness of drilling and completions parameters. The sources of these data span: engineering, geology, and geophysics; and assimilating such diverse information is daunting and beyond the comprehension of crossplotting or other basic statistics. However, modern analytics offer techniques for combining many different sources of data in comprehensive, non-linear models - and characterizing the impact of location and engineering on well production.

Method

In our study, we have created a regional database of more than 3500 producing Eagle Ford wells with reported drilling, completions, and production engineering data; merged with available geologic top, geochemistry, and other relevant data. Using predictive analytic techniques, this information was used to correlate geologic and drilling/completion engineering data with individual well performance – highlighting production trends and optimal engineering parameters.

Data preparation entailed extracting relevant data from the Texas Railroad Commission site and creating a database including: well locations, directional surveys, initial production, and completions parameters. Production in the Eagle Ford ranges spans dry gas to the southeast, at depths of 10,000 to 12,000 feet; to a mixture of natural gas and liquids; to oil with natural gas, at depths of 5000-8000 feet, to the northwest (Figure 1).

Initial production rates for Eagle Ford wells range from more than 6000 barrels per day of oil to over 20 mmcf of dry gas, across the dip trend. To facilitate well-to-well comparisons, all production data was converted to barrels of oil equivalent (BOE's), using a factor of 5800 (divided into mmcf gas production). A production distribution plot for a representative sampling of wells is shown in Figure 2.

Standard operating procedure in the Eagle Ford is to drill horizontal wells of 3000 to 8000 feet with 10 to 30 hydraulic fracture stages. A total of 70,000 to 300,000 barrels of water and 2 to 7 million pounds of proppant are typical completions parameters. These and other engineering parameters such as pressure, were obtained from the Texas Railroad Commission site and were incorporated into the study database. Initial well production rates as well as monthly production rates were also extracted from the Texas oil and gas repository. Production rates were averaged over 90 and 180-day periods for applicable wells, with these measurements being designated as the response variable to be predicted.

As certain, if not all, engineering variables are expected to have a non-linear relationship with well production – linear predictor techniques were deemed to be inadequate for this study. As insight into the impact of engineering parameters on production was desired, neural network techniques were also discarded. The chosen technique for this study is a non-linear, multi-variate approach that iteratively models a response variable (production) from a number of predictor variables (well length, fracture length, fluid/ft, proppant/ft, etc.). A piecewise continuous function is applied to the predictor variables, in order to transform them into linear predictors of the response variable. The summation of these transform functions are compared to the response variable values and an error function is estimated. This error function is iteratively reduced by modifying the predictor transforms until an optimized solution has been achieved.

The non-linear predictor model for estimating production, using a subset of wells, has a much higher correlation with production, than any individual predictor variable. This initial non-linear model is shown in Figure 3.

The Upper and Lower Eagle Ford reservoirs are generally comprised of calcareous mudstones, bracketed between the Austin Chalk above and Buda Limestone below. The depth of the Eagle Ford is a major factor driving production and is likely related to pressure and geochemical factors of Total Organic Carbon (TOC) and thermal maturity, which control petroleum conversion from kerogen. Other geologic considerations, such as thickness of the lower and upper Eagle Ford formations, are important considerations for modeling production. This geologic information was extracted and averaged over every wellbore path and included in the non-linear modeling analysis.

Seismic data is essential for understanding detailed geologic constraints in the Eagle Ford play, including: fault locations, fracture trends and orientation, and rock fracturing characteristics. Advanced seismic fault attributes were used to identify the major fault trends that have affected production in certain historic wells. Seismic curvature and azimuthal seismic analysis, for anisotropy modeling, are combined to map natural fracture trends and density – which are thought to aid well performance. Elastic inversion were used to create derivative volumes of Young's Modulus, Poission's Ratio and rigidity; to aid in the understanding of how rocks respond to hydraulic fracturing. These seismic attributes were converted to depth or averaged over time windows and, in either case, were extracted over every wellbore path and were included in the non-linear analysis. Figure 4 illustrates the application of a threshold to a fault probability volume, which is then used to estimated wellbore proximity to the nearest fault.

The combination of engineering, geological, and geophysical data produced a comprehensive and highly correlated model of well production. Predictor transform plots were analyzed to provide insight into how specific parameters and properties affect relative well production (Figure 5). With a reliable and explainable non-linear prediction model in place, a normalization of the engineering parameters was performed, by selecting nominal average values for wellbore length, fracture stage length, etc., across the entire Eagle Ford. The result of this workflow step was a production sweetspot map, indicating expected relative well production –if all well engineering was held constant (Figure 6). In other words, a map was created to indicate what the rocks would likely produce, if every well was drilled and completed the same way.

Examples

Predictor transform plots were created and interpreted, for multiple non-linear prediction models. The interpretation for the example in Figure 5 is that longer wells, with larger choke sizes; drilled within the gas depth zone and in the thicker reservoir; and those paths that avoided faults but targeted fracture trends – resulted in the best production.

Setting the engineering parameters in the final model to the nominal average values of 5000 feet, etc.; supported the creation of a map that indicated the combination of geologic and geophysical properties that correspond to the best production sweetspot locations. Economic values were integrated into the model and, driven by the gas/oil ratio, provided insight into the revenue sweetspots of the Eagle Ford, as illustrated in Figure 6.

Conclusions

Modern unconventional reservoirs are challenging to understand and develop, due to the large number of engineering parameters and geologic properties (including those measured with geophysics) that drive well production. Crossplot analyses are insufficient to comprehend the complex interplay of multiple variables. Linear multi-variate statistics are also too simplistic to model the diminishing returns (i.e. non-linear relationships) of reservoir thickness and size of completions – with bigger not always being better. Neural networks can provide a non-linear option for modeling these reservoirs, but do not provide sufficient insight into the effect of different parameters and properties, to drive an optimization strategy.

A non-linear multi-variate technique, based upon transforming variables into linear predictors of production has proven to a robust and reliable approach for assimilating and understanding the constraints for unconventional well production. Using publicly available engineering data and seismic data provide by Global Geophysical, an integrated production predication model was made for the Eagle Ford. In addition to indicating better economic performance north and adjacent to the Sligo shelf margin, this work points to optimal engineering corresponding to: ~5500-foot horizontal wells, with ~250-foot fracture stage spacing - drilled in geologic sweetspots of: reservoir with nominal thickness of ~150 feet, that avoid major faults by at least 1500 feet, yet target fracture trends.

Acknowledgements

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Selected Reference

Hentz, T.F., and Ruppel, S.C., 2011, Regional Stratigraphic and Rock Characteristics of Eagle Ford Shale in Its Play Area: Maverick Basin to East Texas Basin: **Search and Discovery Article #10325** (adapted from oral presentation at AAPG Annual Convention and Exhibition, Houston, Texas, USA, April 10-13, 2011).

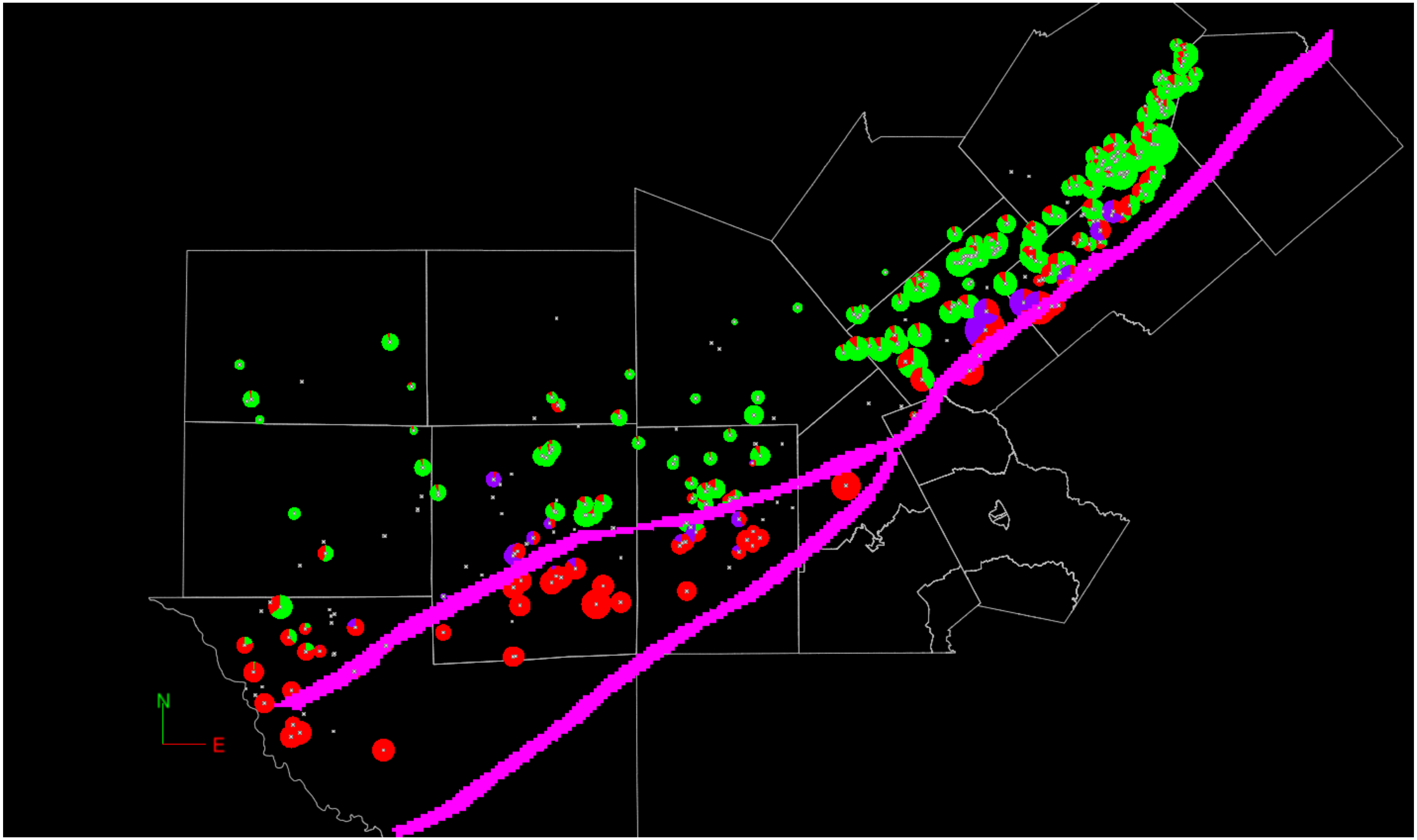

Figure 1. Illustration of well production (BOE's) and petroleum phase changes across the Eagle Ford (red=gas, green=oil, and purple=condensate/natural gas liquids).

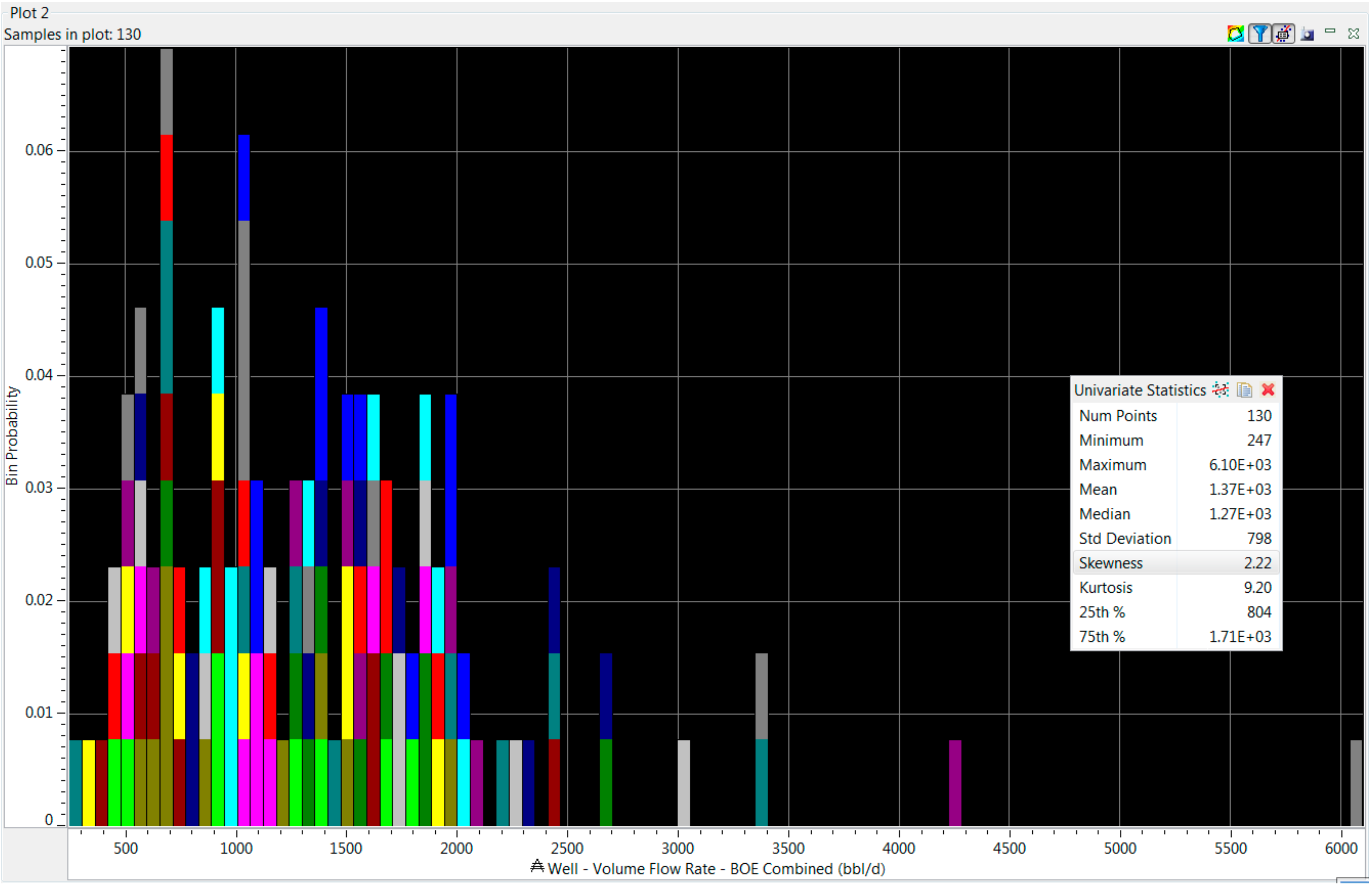

Figure 2. Production variability for a regional sampling of Eagle Ford wells. Oil, gas, and liquids production is converted to BOE's. (Mean production 1370 BOE's – maximum production 6100 BOE's).

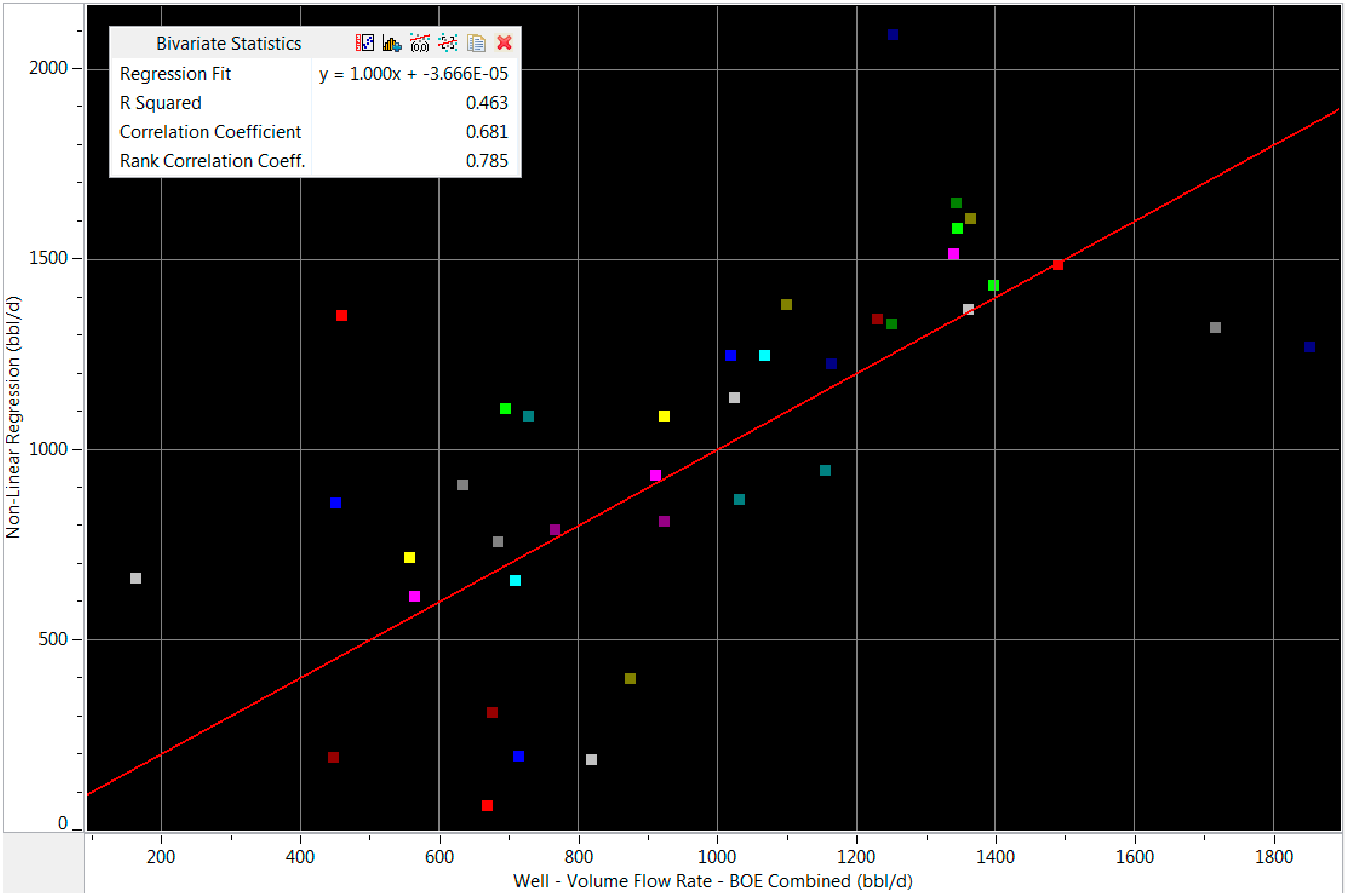

Figure 3. A non-linear production prediction model (y-axis), using only drilling and completions data, has a high level of correlation (.681) with actual production (x-axis).

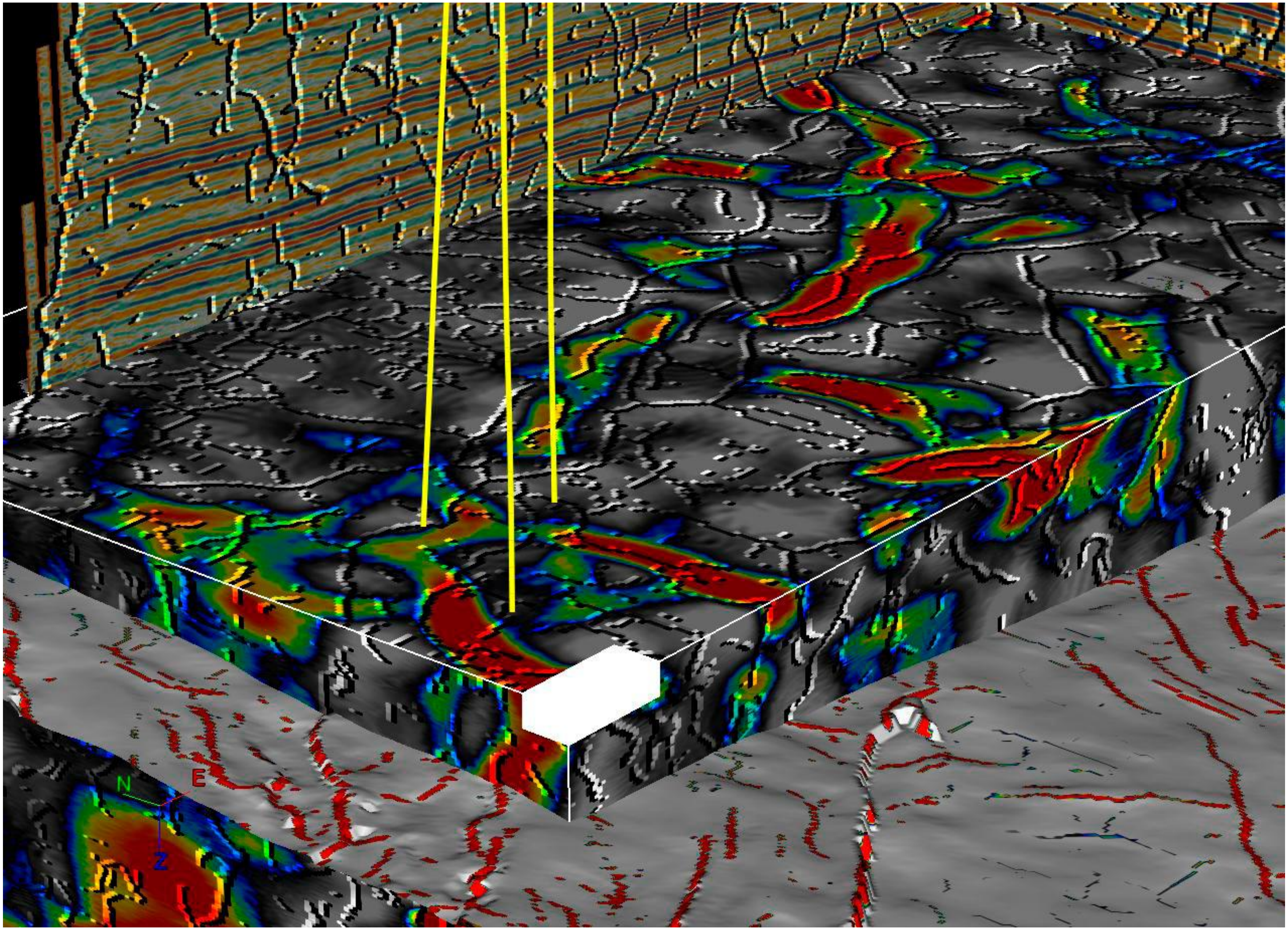

Figure 4. A threshold is set to a fault probability attribute to create a fault proximity volume, where color intensity is an indication of distance to the nearest likely fault. Nearest or average distance to a likely fault is then extracted to each wellbore intersecting the seismic volume.

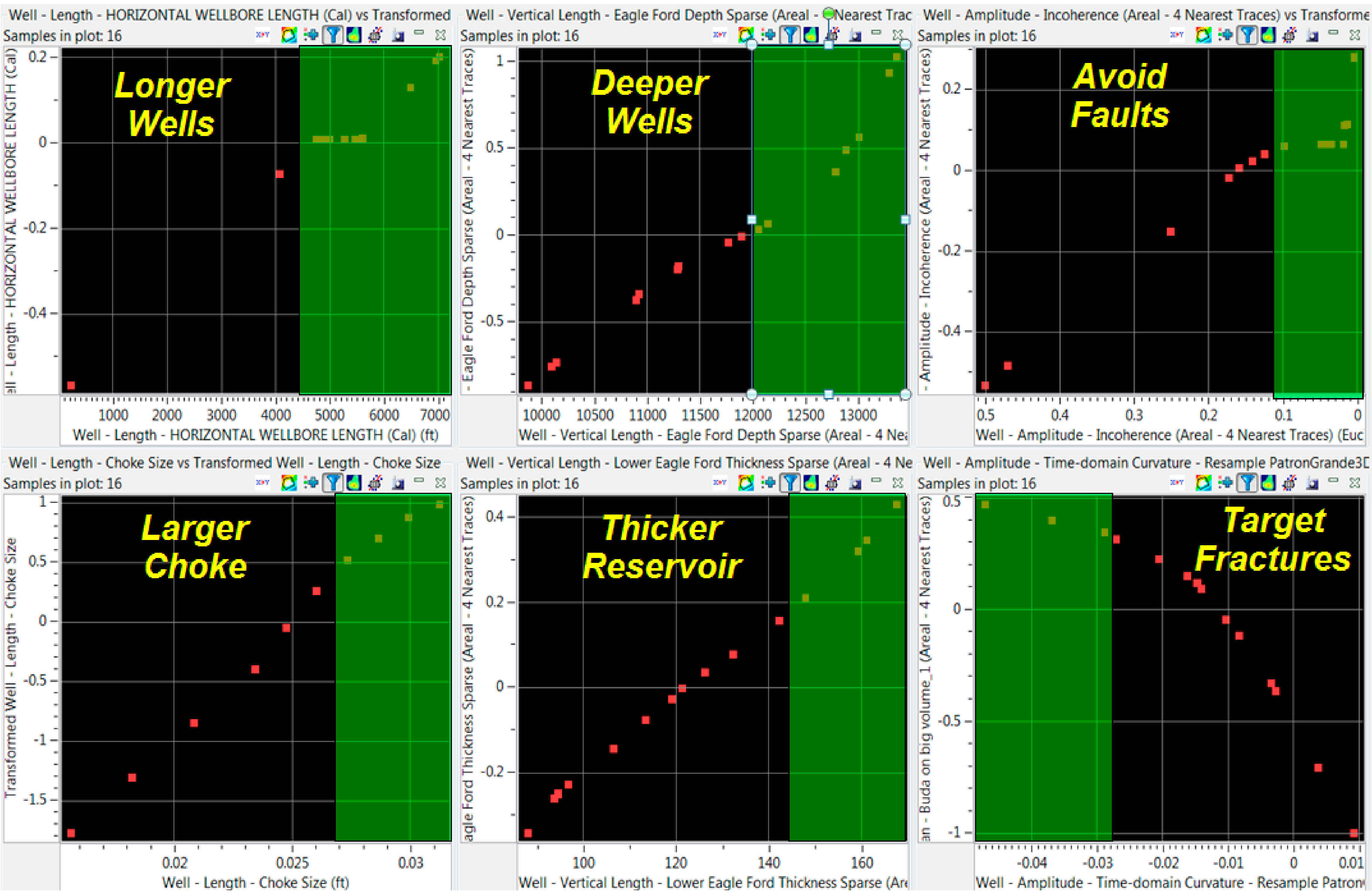

Figure 5. A selection of predictor transformations that highlight (green) the range of parameters and properties that correspond to the greatest well production.

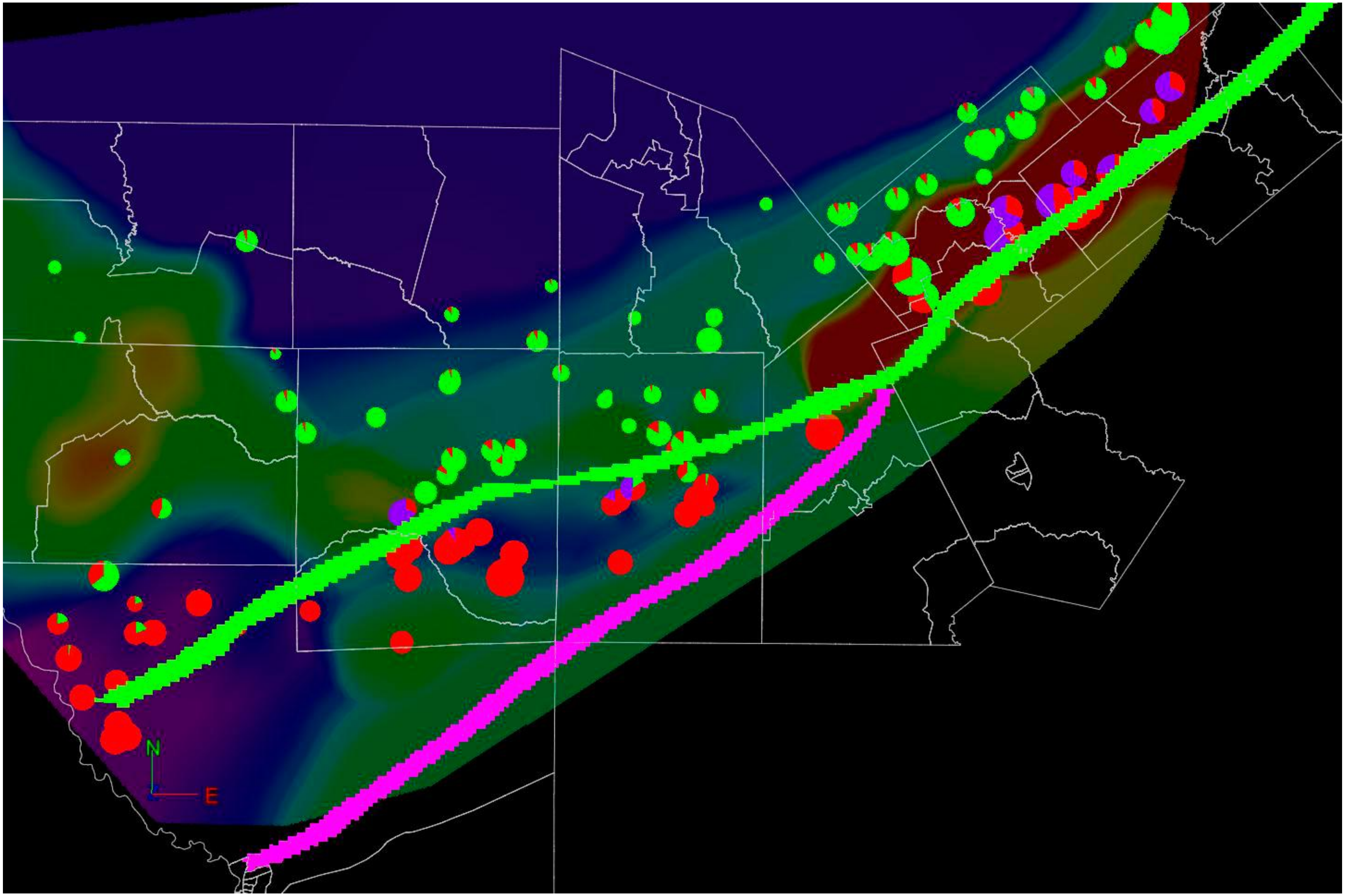

Figure 6. A relative production sweetspot map, indicating the best geology and economics (red) for well production in the Eagle Ford.