Optimization of Horizontal Wells Utilizing Multi-Variate Analytics of Seismic Inversion in the Wolfcamp Formation of the Midland Basin*

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Abstract

The Midland Basin Permian play is a continuous resource play with a minimum of six independent productive zones. These zones vary in geological complexity and exceed 4,500 feet in thickness. Careful consideration is required in order to maximize value of the asset. The play is in the early to mid-stages of the development lifecycle and provides a valuable opportunity to leverage production data from early delineation testing into a statistically valid model for predicting future horizontal production. In 2012, Laredo began testing methods of integrating geophysical, geological, petrophysical, completion, drilling, and production data to regionally high-grade drilling targets across their Midland Basin asset. Bi-variate analysis revealed that higher resolution multi-variate statistics were necessary to develop a local scale model that could forecast production. Utilizing Multi-variate statistical analytics on 82 seismic attributes (pre-stack, post-stack, and inversion), Laredo has created an "Earth Model" based on the combination of five seismic attributes in order to predict cumulative oil production volumes of horizontals at a set point in time. Historical well performance was then used for calibration and initial validation. The model is normalized relative to completion length, completion testing, and spacing from the calibration data to understand the variations of the drivers on production.

The results of the model have undergone further refinement using microseismic, petrophysical, and empirical data, all of which further validity of the results behind major geological contributors of production. The model was confirmed utilizing a population of blind test wells, which resulted in a correlation 0.85 of actual versus predicted cumulative 90-day oil production.

The goal of Laredo's Multi-variate analytics is to improve well performance by maximizing lateral length in the most productive portions of the formation with an optimized well design and completion methodology. This technique, based on high quality 3-D seismic, can be utilized in any unconventional play where good sample sizes of production and high quality geological information are available in order to high grade drilling inventories and improve individual well performance.

Introduction

Attempts to utilize conventional mapping and high grading techniques on the Wolfcamp Shale of the Midland Basin have yielded regionally graded areas not delineated by local variation and which are not captured with open hole log distribution. Due to the thickness of the Wolfcamp Shale unit, multiple landing points are needed to fully develop the asset and ranking and high grading not only regional areas but vertical development as well is paramount.

Laredo's entry into the Wolfcamp play began in 2011. By the end of 2012, thirty-two horizontals were producing across the acreage position. The production results showed variations in cumulative oil rate which could not be solely related to one known parameter. To understand the controlling factors on the variability in a laterally heterogeneous reservoir, Laredo's Phase 1 modeling began with utilizing geo-cellular modeling to extrapolate petrophysical values in the subsurface more accurately (Figure 1) and, ultimately, to identify sweet spots within the acreage position (Figure 2).

Extractions of petrophysical and mechanical variables along the length of the laterals were compared to the well performance utilizing bi-variate analysis methods. Correlation coefficients of 0.5 or lower showed weak relationships with production (Figure 3) indicating that there is no single primary driver in well performance. It was quickly determined that grading multiple parameters based on arbitrary cut offs to predict areas of increased well performance will not yield an accurate result. Instead, a methodology is required to statistically relate the combination of multiple parameters to well performance.

A high density of core, seismic, and open hole logs data, combined with an extensive aerial distribution of horizontal production data, presented an ideal opportunity to implement the next round of modeling, Phase II. Phase II modeling utilizes Multi-variate statistics to relate well performance to seismic inversion products based on petrophysical relationships that has been calibrated to core data. The integration and extrapolation of petrophysical responses in seismic inversion products is described by Young (2009).

The initial multi-variate model began with 21 horizontals that had 90-days of production data. After normalizing the data for variations in completion type, operational issues, and completed lateral length, the model was developed with 17 horizontals. Fifty seismic attributes were compared to production. The final product was a combination of three seismic attributes per model and the average of five models. Each of the five models had a mechanical factor (Young's modulus, MuRho), a structural or natural fracturing factor (Positive Curvature, Curvature Inclination, Maximum Curvature, Frac Factor) and an interval thickness variable (Spectral Decomposition). The correlation between the prediction and actual 90-day cum was 0.92. Additional information and description of Laredo's Phase I and Phase II process can be found in Curth et al., (2015).

A second iteration of the multi-variate model was performed due to a significant increase for horizontals that had reached 90-days of production, creating additional control in all zones. The model included 41 horizontal wells and after normalizing for spacing and completion impact, the model was created with 37 horizontals (19 Upper Wolfcamp, 11 Middle Wolfcamp, 4 Lower Wolfcamp, and 3 Cline). The number of seismic attribute products increased to 78. Through collinearity analysis and multi-variate statistics, 78 attributes decreased to 10 that were then combined through five models of four to five attributes each. Each of the five models had a mechanical factor (Young's modulus, Shear velocity, Shear impedance), a saturation or lithology discriminator (porosity, resistivity), a structural or natural fracturing factor (Kpos, Kdip, Kmax, dip azimuth), and an interval thickness variable (Spectral Decomposition). The correlation coefficient of the prediction was 0.85. Blind wells were used to test the model's accuracy, and are referred to as the validation well set. The resulting correlation was 0.79 (Figure 4). This volume was tested against production logs and single zone tests that showed the same directional relationships to the model response. Microseismic was plotted against the model and containment of events could be seen at areas of lower predicted production, with intervals of higher expected productions showing an increase in event count. The model was related back to rock parameters by extracting the prediction response at wells with petrophysical logs. Utilizing the petrophysical logs, a probabilistic model was developed to recreate the model's 90-day cum prediction as a log at any well. The petrophysical relationship was critical to ground truth the model and to extrapolate results into areas where high quality seismic was not available.

Expansion multi-variate models were created in areas of significant well density utilizing the same workflow that was established in the initial model and subsequent models. The models were based on the same 88 sq. mile extent as previous models and had similar correlation coefficients. The benefit of the localized data sets was the mitigation of extrapolating predictions into untested areas and developing false positives. The limitations of localized models lie in the ability to create regional comparisons across the acreage position, and executing wells that transitioned between two models. These models were discussed in Wicker et al., (2016).

Through multiple rounds of updates and expansions (Figure 5), the Earth Model now covers the majority of Laredo's acreage and utilizes 228 wells for calibration in a contiguous model that has three distinct sub-models based on stratigraphic intervals. The improvement in the modeling methodology can be seen in the higher correlation of the model zonation to stratigraphic intervals (Figure 6). The models are developed using 82 attribute products and the final models are a combination of three engineering based variables and up to six seismic products. To date, the Earth Model has been implemented in planning and drilling 91 horizontals with a correlation coefficient of 0.74 between predicted and actual production. The average accuracy for all wells that have used the Earth Model is 95%.

In addition to planning wells, the Earth Model prediction has been used to normalize the geological variation between lanes to better understand the impact of well spacing and completion design. This type of evaluation has assisted Laredo in developing a completion strategy of higher sand concentration. Further information on impacts of the Earth Model is outlined by Courtier et al., (2016).

Earth Model Creation Methodology

The methodology described below has been refined through many iterations of the model development. The model workflow is illustrated in Figure 7. Initial requirement for model creation is depth-converted seismic volumes to accurately extract seismic variables. The utilization of all synthetic well ties in addition to all available well control helps to ensure minimum variation when relating petrophysical properties to seismic data for the creation of post- and pre-stack attributes.

First, seismic variables are sampled along the completed length of the lateral at multiple widths to assess the impact of radius size on the average seismic response at each lateral. Several tests determined that the amount of variation decreased at a sample radius of 80' around the wellbore. The seismic inversion product is averaged to a single response for the length of the lateral, which can then be conveyed into analytics.

The response variables used to compare well performance are 90 and 180-day cumulative oil production with non-production time removed. The start time of the calculation is standardized to the first day of oil production during flow back. Horizontal wells are divided into groups that are in similar lithologic and stratigraphic intervals so that parameters controlling well performance in one zone are not extrapolated to zones of differing deposition or sourcing. The current methodology in place separates the vertical interval into three distinct units.

Engineering variables are brought into the analytics in order to normalize well design parameters from geological contributions. Among these variables are completion length, proppant volume, stage spacing, well spacing, distance to existing horizontals, well inclination, and azimuthal variation of the wellbore. Each variable is summed or averaged for the entire completed portion of the wellbore.

The primary multi-variate model used only engineering variables in order to identify dominant controllers of production that are integrated into the seismic-based Multi-variate models. Engineering parameters identified as dominant controllers are lateral length, total proppant volume, total acid volume, well spacing, and proppant concentration as shown in Figure 8.

The oil prediction model starts with all variables tested through multi-collinearity to remove any redundancy and to ensure that independent variables are tested in modeling. Variables that are correlated to direct measurements of fractures, lithologies, thickness, or mechanical properties are forced to be retained over ambiguous variables.

Variables are combined utilizing non-linear regression methodology and initially checked with N-fold validation. N-fold validation is the process of removing a set of the calibration population and re-running the model to understand the accuracy and amount of error. The number of variables per model is limited to a maximum of one variable per 10 horizontals in the control set.

This ensures that the data is not over fit. Higher levels of correlation can be achieved, but the potential of over fit solution increases as illustrated in Figure 9. Multiple models are created for each interval and those with the highest correlation are combined to produce a 3-D SEG-Y volume showing the predicted attribute. Engineering variables are held at the current completion and spacing parameters for the model's end result.

The validation process begins by extracting the model at vertical wells containing a significant amount of data to relate the prediction of well performance to known log responses (Figure 10). Wells with production information that do not have all the parameters used in the calibration are utilized as blind wells. Current blind well tests must fall within one standard deviation of the prediction in order for the model to be considered valid. Model responses are qualitatively compared to single zone tests and production logs to ensure that the model is showing the same lateral variability as all direct measurements. Microseismic is compared to understand fracture buffers and to identify potential containment between zones.

Location Grading and Well Planning

Regional variation in the quality of targets can be viewed by looking at the average magnitude response of the defined intervals of interest to develop high-graded regional areas. To provide insight to the economic impact with variation in landing point or lane selections, extractions are run for each landing point in each lane in order to grade the relative production for each target (Figure 11). The relative production output can then be scaled to show the impact of target selection on full development, based on the current spacing assumption. Extractions can be scaled to the correct lateral length, completion volumes, and current spacing to formulate an estimate of oil production in 180 days, which in turn can be incorporated into economic analysis.

To implement the proposed well path, a pseudo-directional survey is created based on the highest predicted target in the volume. A quality check is performed to ensure depth accuracy of the model to the offset petrophysical response along the well path, which is then sent to directional planning to produce a drillable well plan.

Modeling Impact on Well Performance

Utilizing Laredo's latest Earth Model for well execution and optimized completion techniques well performance has increased by 36% above Laredo's 2017 type curve (Figure 12), through production of 2/15/2017. In total Laredo has implemented the Earth model on a total of 91 wells and of those wells 66 have had optimized completions. For all Earth model implemented wells the average Earth model prediction is 95% of the actual production at the 90 day cum time period.

Conclusions

Utilization of seismic responses based upon relationships to rock properties can provide a tool to reasonably estimate horizontal well performance in unconventional resource plays. Laredo has developed models based on mechanical properties, natural fractures, fluid saturations, and interval thickness to extrapolate well performance across the Midland Basin acreage position. This methodology can provide insight to economic evaluation and impact well performance by placing and steering wells in zones with higher production potential. The Multi-variate approach provides a methodology to condense large and dynamic data sets into a package that can be interpreted and utilized to delineate the relative impacts of variables on production.

Acknowledgements

We express our appreciation to our colleagues from eSeis, Halliburton, and Global Geophysical who provided insight and expertise that greatly assisted in the development of the Earth Model technique, although their views may not be conveyed in this paper.

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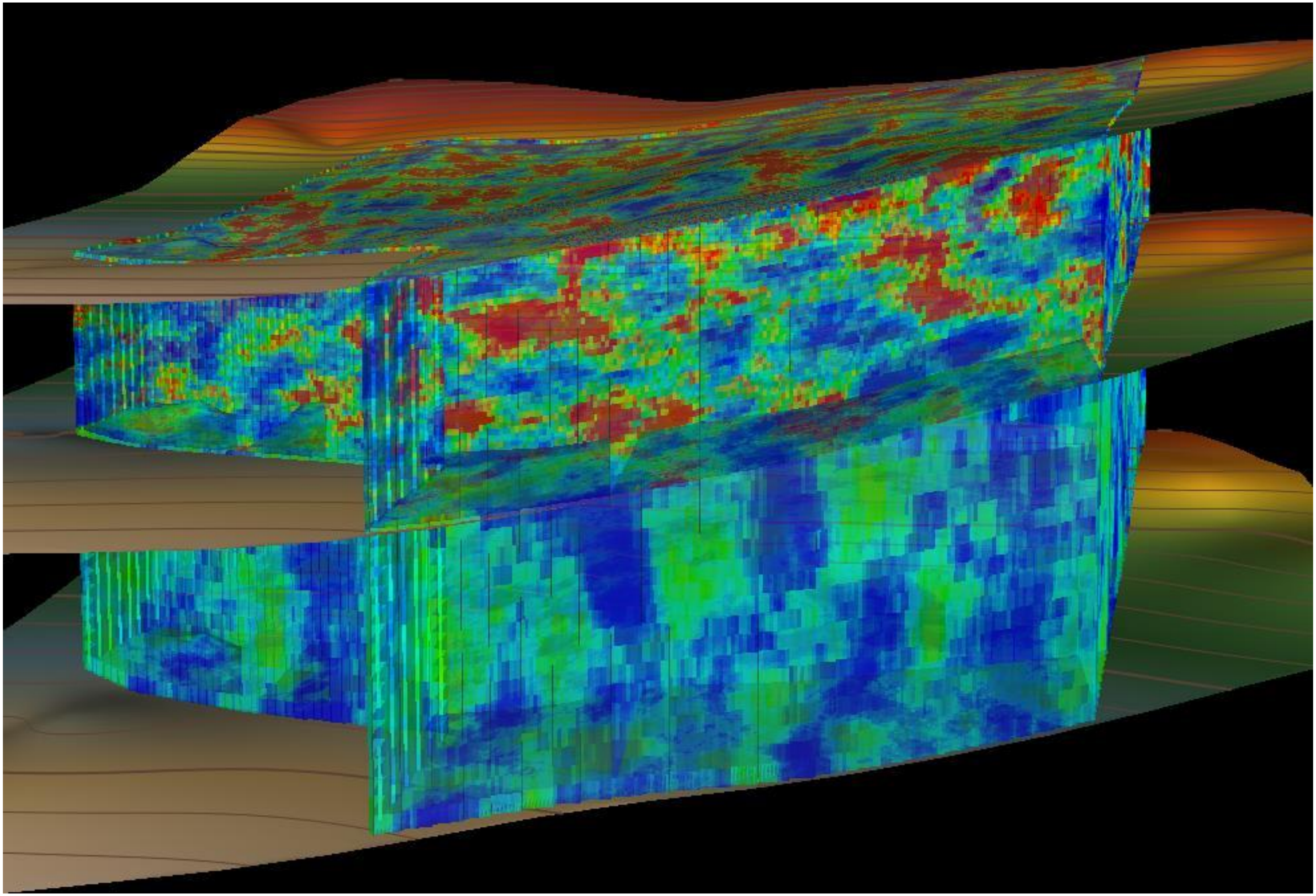


Figure 1. Example of Phase 1 geo-cellular model indicating lateral discontinuity in hydrocarbon pore volume and vertical dispersion that requires multiple lateral landing points to develop.

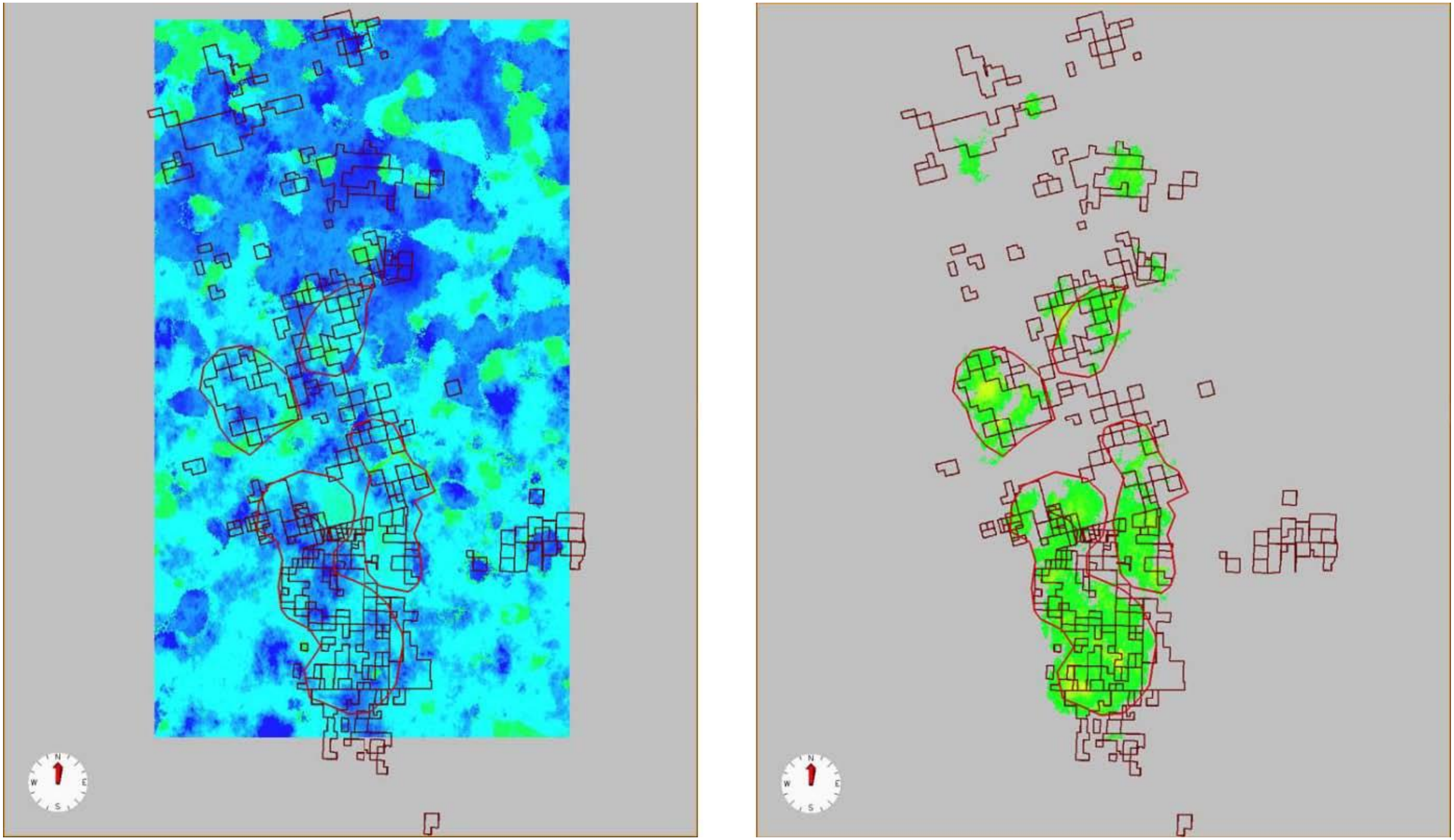


Figure 2. Example of Phase 1 regional grading based on hydrocarbon pore volume for a single landing point. Arbitrary cutoffs were used to high-grade acreage.

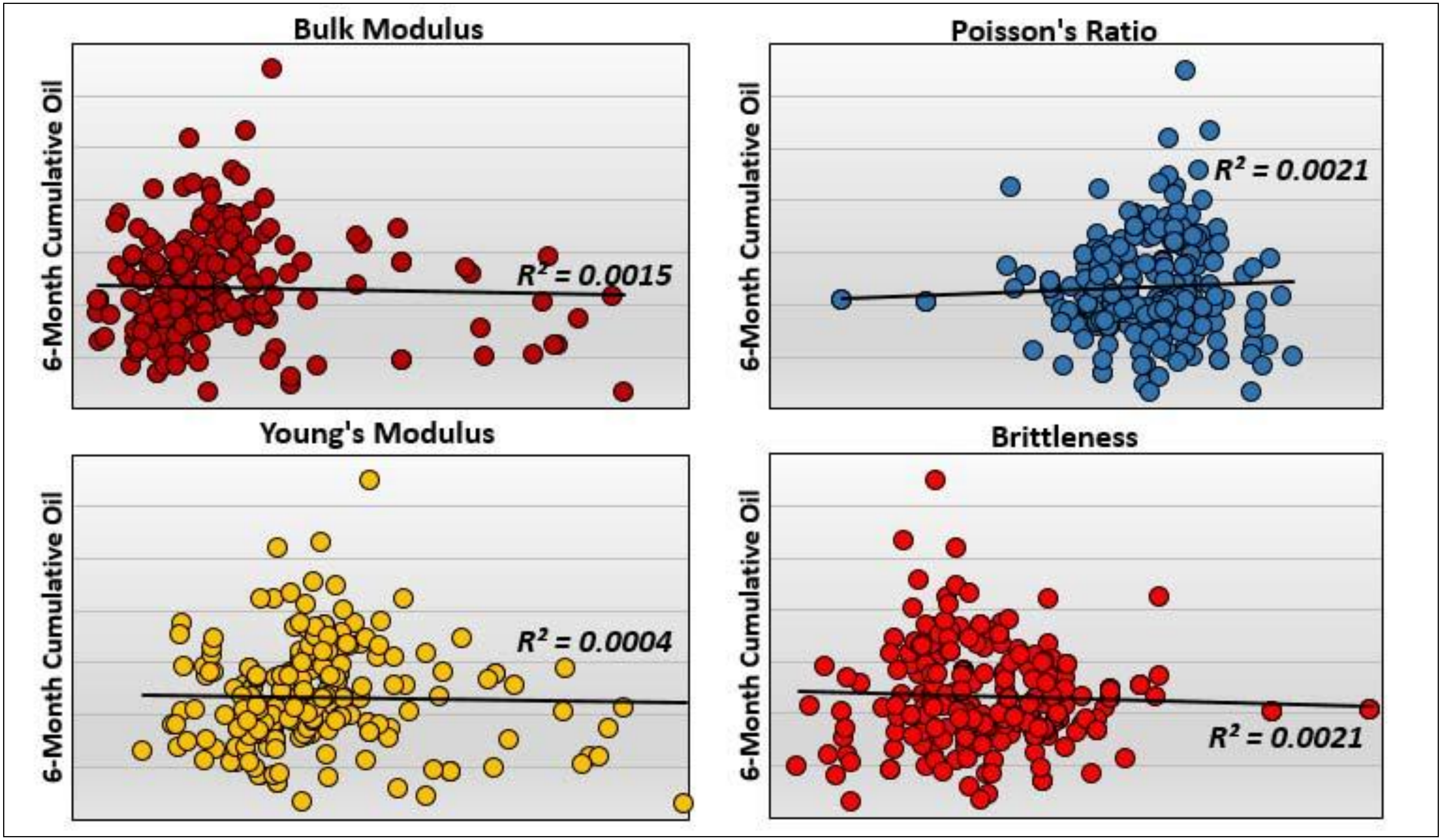


Figure 3. Example of bi-variate cross plots single variable against production metric. Bi-variate analysis yields low correlation of any one variable to production.

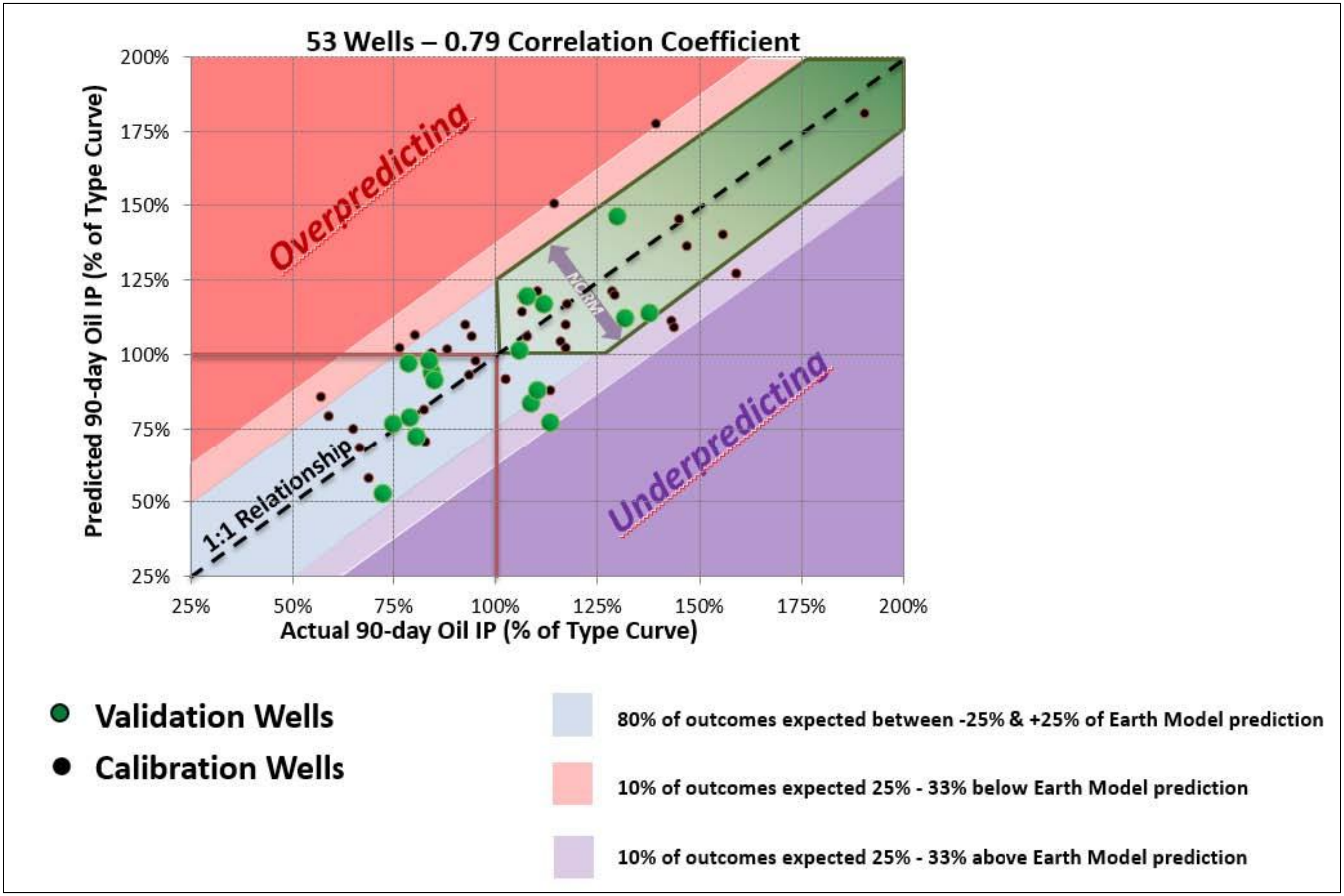


Figure 4. Validation of Earth Model with blind well performance.

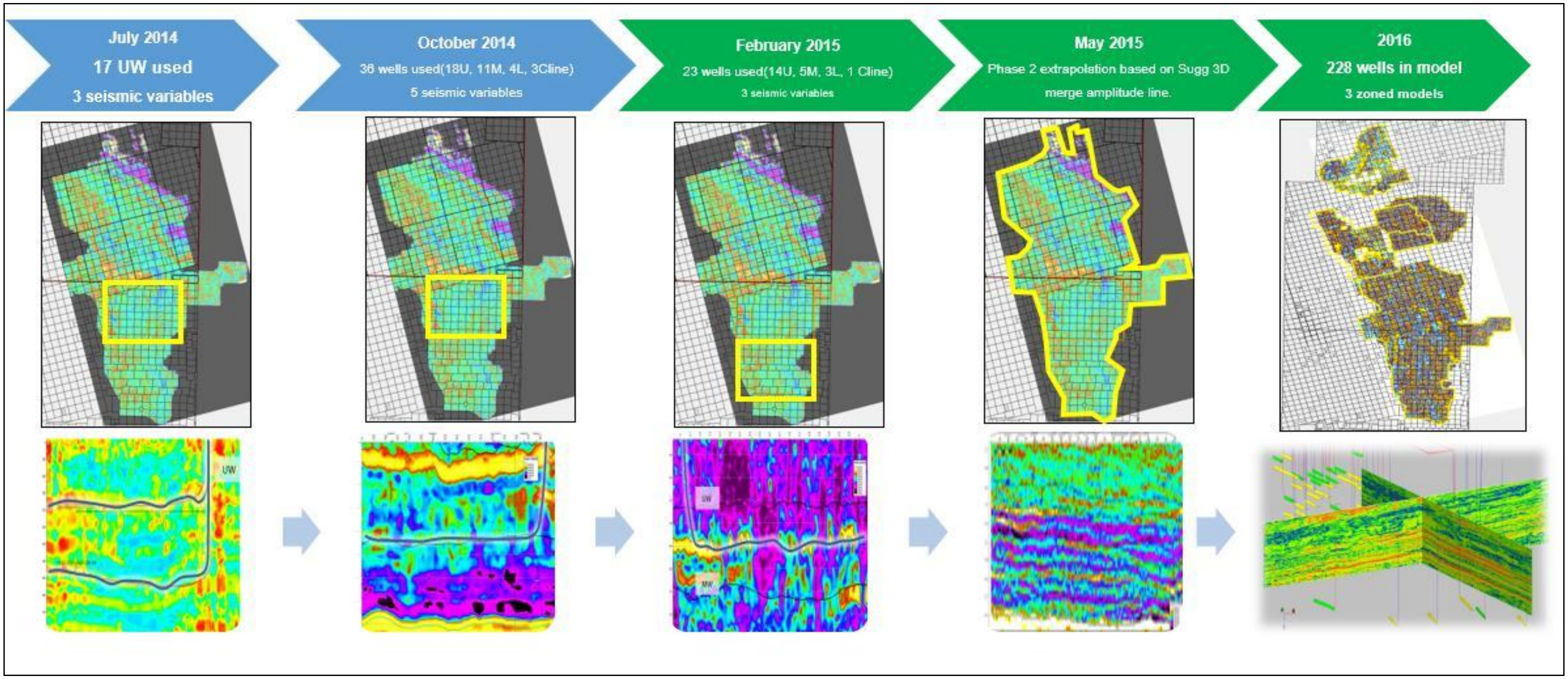


Figure 5. Progression of Earth Model during course of project to gain additional control and aerial coverage.

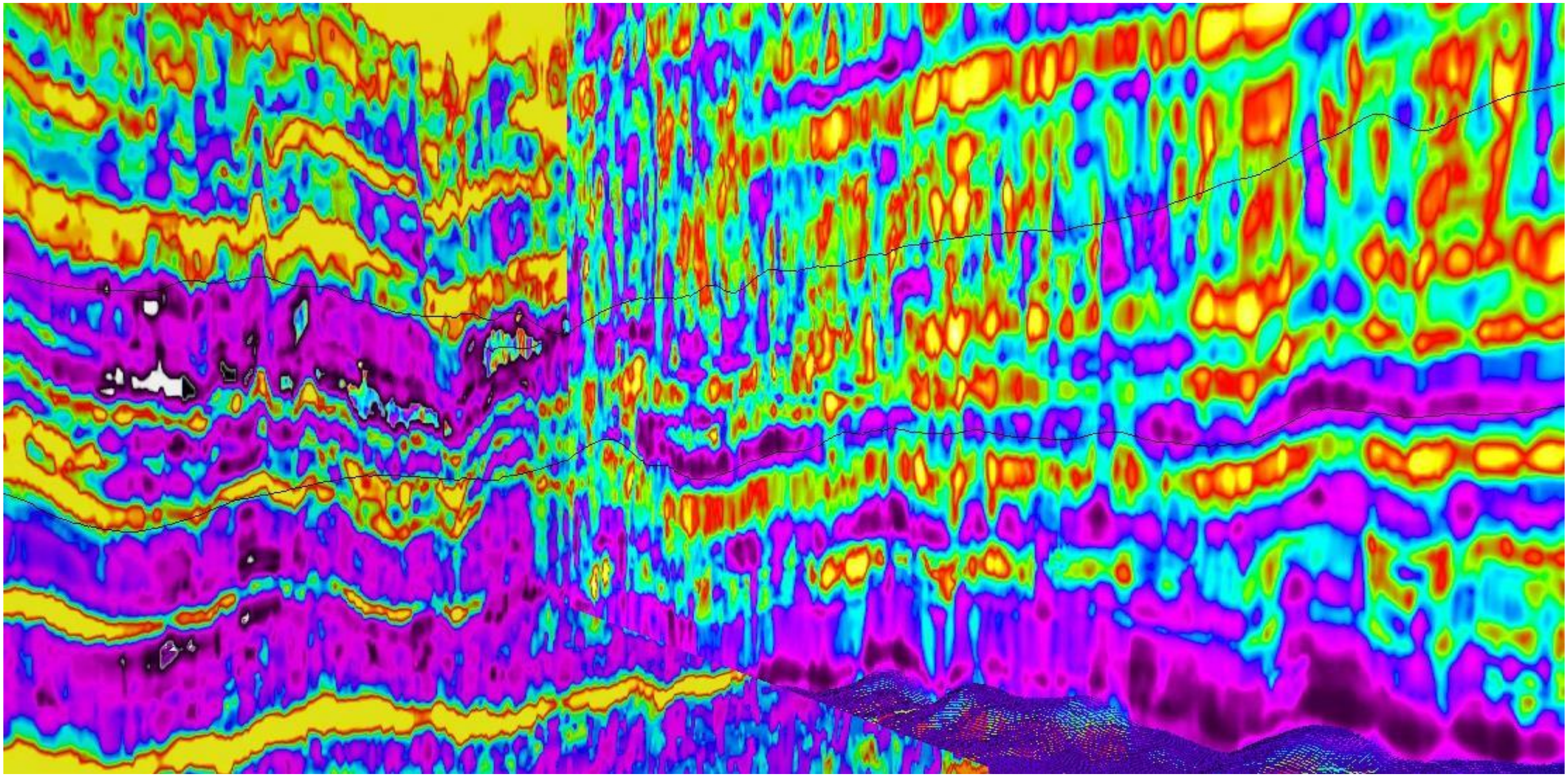


Figure 6. Updated model provides higher resolution and better relation to stratigraphy compared to original fast track models.

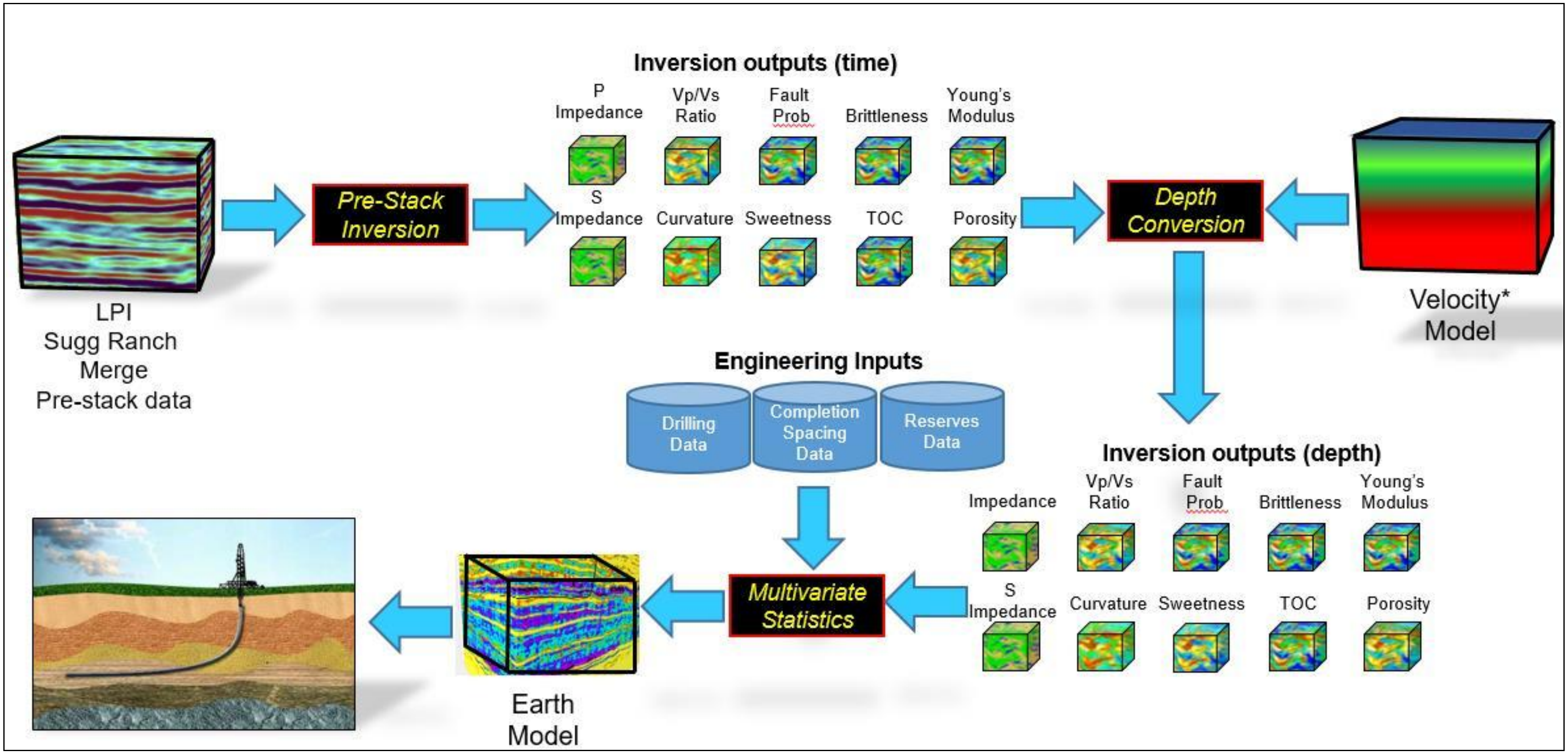


Figure 7. Workflow for creation of earth model.

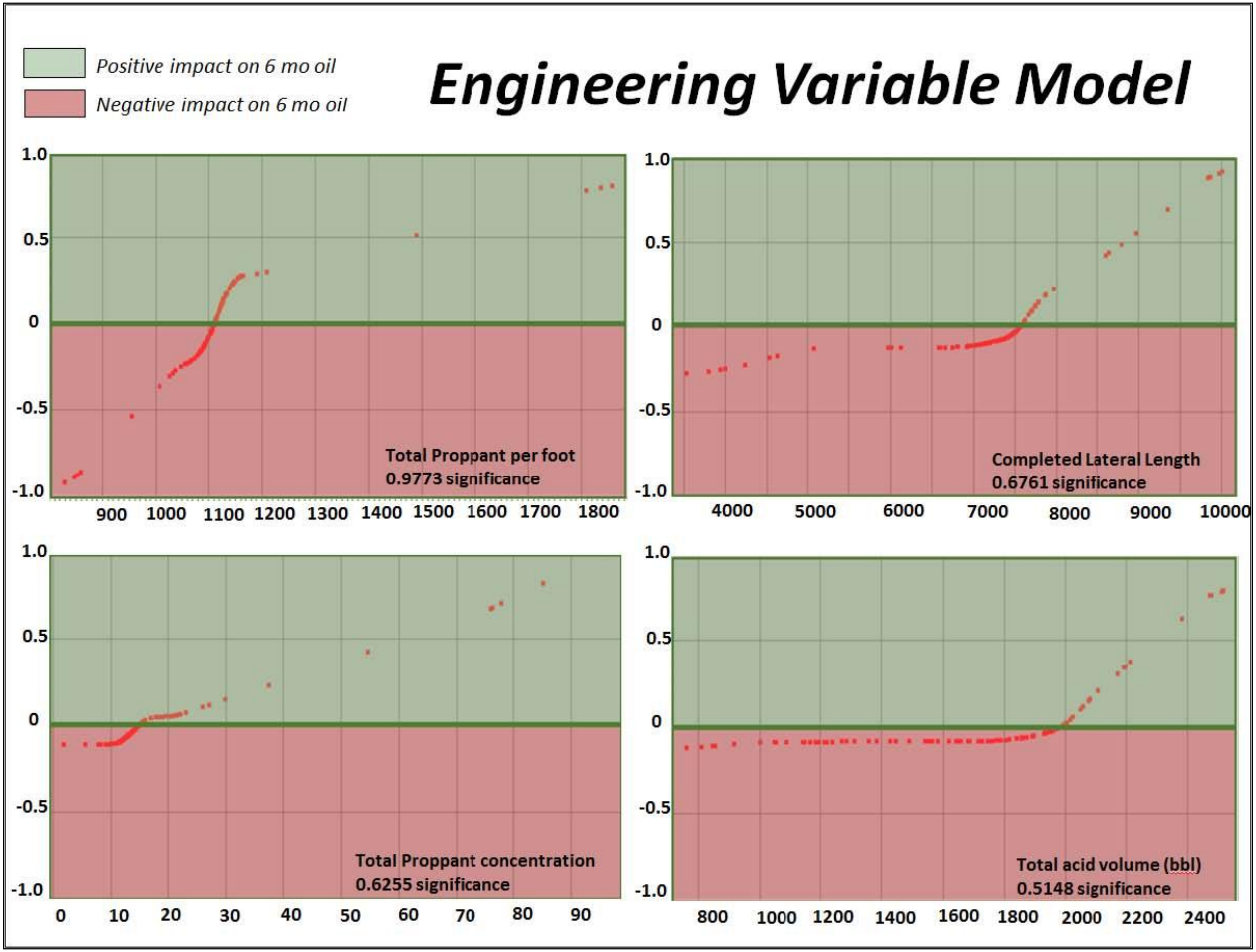


Figure 8. Engineering variable model, showing that lateral length and proppant volume as the primary drivers are needed in the final modeling.

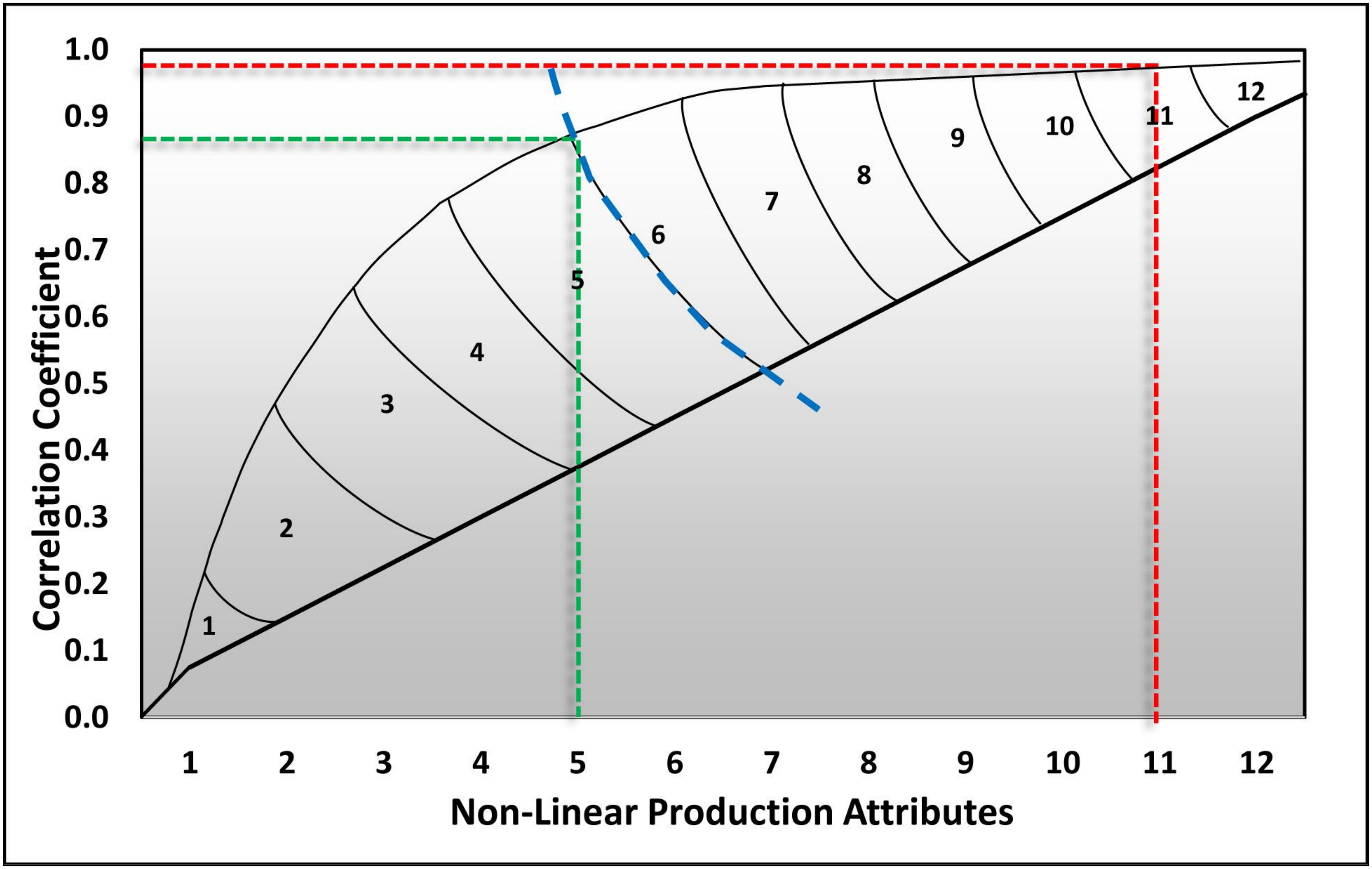


Figure 9. Illustration showing the diminishing rate of increased correlation coefficient with the addition of variables into a non-linear solution.

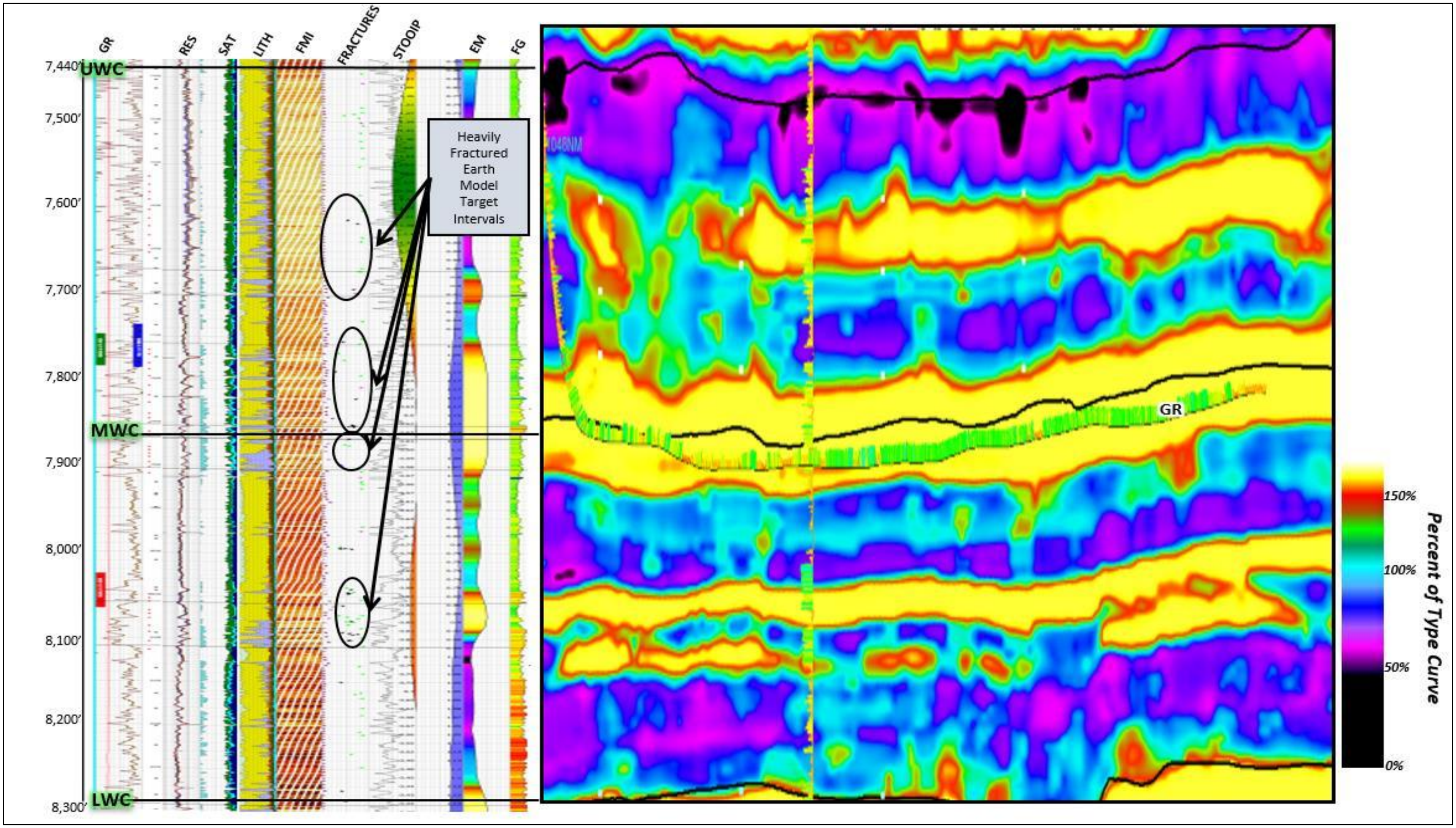
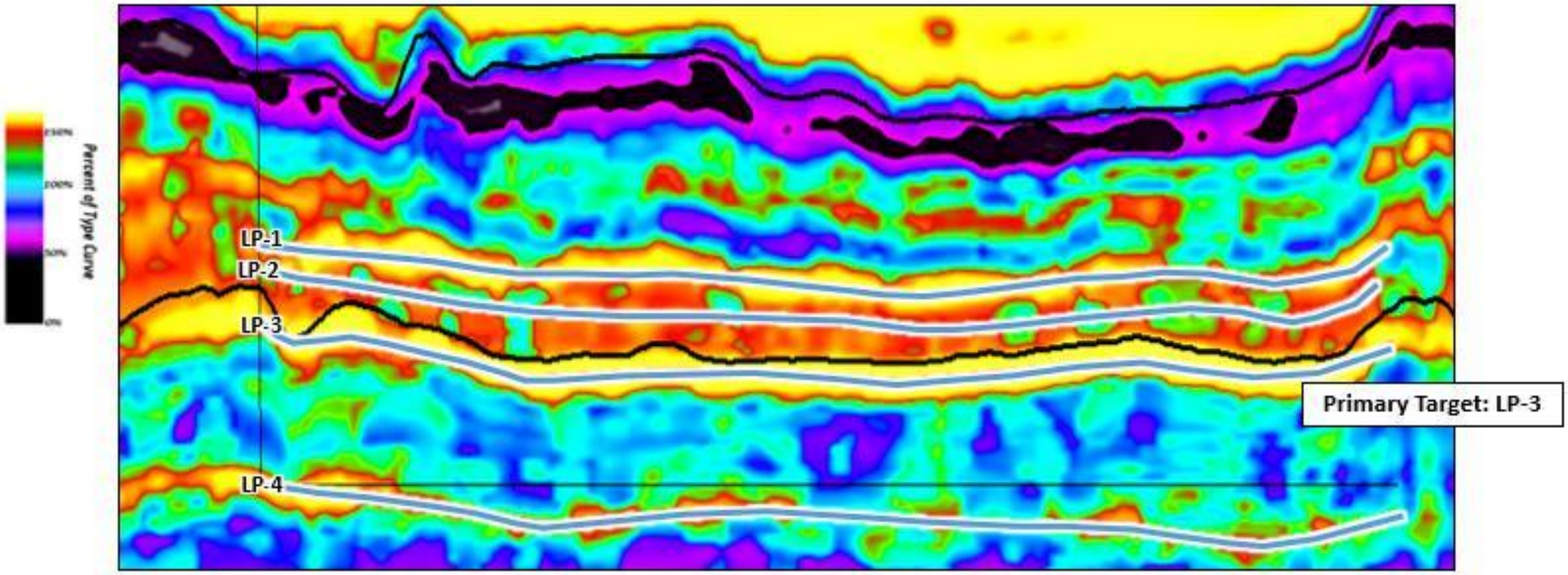


Figure 10. Validation of Earth Model by relating response to petrophysical and fracture measurements. Log (FRACTURES) are interpreted FMI fracture sets, and log (EM) is the petrophysical re-creation of the Earth Model response.



Landing Point	Scaled 90-Day CUM. OIL Prediction	% of Type Curve
LP-1	56,146	111%
LP-2	63,423	126%
LP-3	60,394	142%
LP-4	45,888	108%

Earth Model extraction drives landing point selection

Figure 11. Ranking of lateral landing points in a single lane to high-grade development.

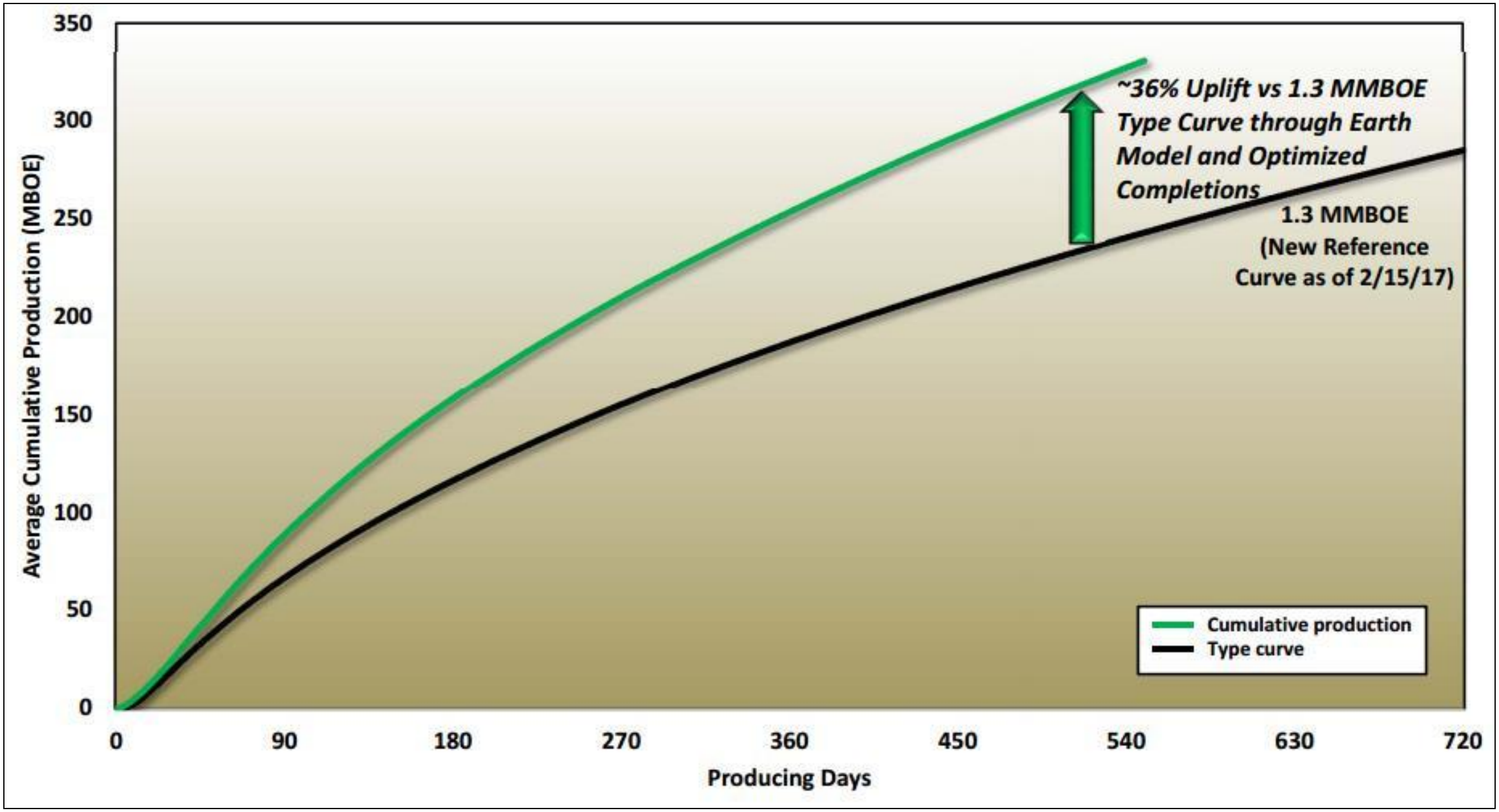


Figure 12. Cumulative production of the population of Earth Model wells compared to Laredo's type curve.