Modeling Unconventional Resources with Geostatistics and Basin Modeling Techniques: Characterizing Sweet-Spots Using Petrophysical, Mechanical, and Static Fluid Properties*

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Abstract

Unconventional resource plays have become front-and-center in the exploration and development arena, particularly in North America. Effective modeling efforts of these resources are struggling to keep pace with exploitation, principally because of the novelty of these source/reservoirs. Best modeling practices have yet to be established with successful stimulation treatments. Currently, the industry is in a state of trial-and-error, with only immature research results available to help improve defining the physical characteristics of so-called "sweet-spots" and the appropriate methods to stimulate them. Practical workflows to describe these source-reservoirs for sweet-spot identification can be created using conventional geomodeling techniques with some modifications and innovations. Traditionally, reservoir geomodeling has focused on present-day descriptions of static rock properties in the subsurface in a localized area. Such models could be stochastic or deterministic, but these techniques have no capability to describe the means by which the reservoir arrived at this current state, nor the predictive condition of the petroleum fluid properties residing within. The state of petroleum is usually determined in a basin model, which simulates, through time, a variety of conditions and variables, such as sedimentation, burial, erosion, uplift, thermal condition, pressure calculations, diagenesis prediction, etc.—all of the processes acting on rocks and fluids during the development of a sedimentary basin. These calculations are generally applied to entire basins or large portions of them. This article combines geostatistical reservoir modeling along with classical basin modeling techniques to identify the source-reservoir sweet-spots in unconventional plays, along with their rock and fluid characteristics that define the formation.

Introduction

While the roles of source and reservoir rock are reasonably well understood in conventional resource development, source reservoirs are not so well understood in unconventional (shale) plays. Traditional workflows and methods for identifying "good" versus "poor" quality in such reservoirs do not work very well and continue to elude operators. Despite being well into the second decade of shale exploitation and consistently keeping drilling and stimulation designs within current best practices, understanding the variability in rock quality is still difficult. There are a variety of reasons for this, such as the lack of clarity around shale facies themselves and the difficulty of remotely identifying their quality with current tools. Figure 1 shows the statistical variability of 100 horizontal wells drilled by one operator in one portion (20 □ 22 miles) of the Barnett shale core area during a two-year period after stimulation best practices had been, by and large, resolved (Chorn et al. 2013). Initial month production rates (per 100 ft of lateral length) vary by a factor of more than 10; four-year cumulative production (per 100 ft of lateral length) varies by a factor of 22.

In unconventional resources, unlike traditional reservoirs, far more emphasis is given to mechanical rock properties that measure components of elasticity and non-elasticity. The principal emphasis is to identify the maximum direction of stress, and common wisdom is to induce fractures perpendicular to it. Further, consideration should be given to other mechanical and petrophysical properties to discover where the rock is most fracable. The assumption is that there are combinations of measurable properties that, when mapped, can identify areas or zones that are more susceptible to stimulation than others. To complicate this modeling effort, many of the resource plays appear to be naturally fractured. Successfully defining the mechanical sweet-spots likely requires an understanding of the existing natural fracture system, when present. Induced fractures will likely respond differently in the presence of natural fracture systems. In this regard, there has been an industry-wide resurgence in the use of software that allows direct modeling of natural fractures in an attempt to create more realistic dynamic-flow modeling in unconventional plays.

Finally, the integration of petrophysical and fluid properties must be captured. While it is common and generally important to populate models with petrophysical properties, such as porosity, permeability, and even total organic content (TOC), it is important to recognize the role that matrix properties play alongside the complex discrete fracture network (CDFN) and the coalescing of the natural (discrete fracture network, or DFN) and induced fracture networks (complex fracture networks, or CFNs). This integration can be achieved either in a traditional structured grid system or in a non-traditional unstructured meshing system that is compatible with industry flow simulators (Figure 2); however, further discussion of this topic is beyond the scope of this article.

These properties serve not only to add valuable information to improve static modeling, but also to improve the final stage of flow modeling. Because of the relatively short time frame within the basin history in which the shale resource was deposited, it is computationally possible to calibrate a dynamic version of the regional basin simulation model to a smaller volume and scale of resolution. The advantage of doing so is that by modeling the geohistory of the reservoir-scale earth model, the entire history of the reservoir, and its constitutive fluids, can be recreated, not only helping to validate the structural integrity of the model, but also to determine when the hydrocarbons were generated, exactly where in the reservoir they reside, the quality of the hydrocarbons (over-/under-cooked), and the current state of the hydrocarbons (gas, liquid-rich, oil).

Contribution of the Static Earth Model (Reservoir-Scale)

The contribution of the static earth model is two-fold; it provides a three-dimensional (3D) representation (deterministic or stochastic model) of the current distribution of both petrophysical and mechanical properties in the context of the present-day structural framework, and it also provides input into a variety of downstream operations, such as well planning and flow simulation (Yarus and Chambers, 2006). A significant difference between earth models for conventional and unconventional reservoirs is the emphasis in the latter on mechanical properties. Optimally, a model of an unconventional resource would provide information on the distribution of matrix properties, natural fractures, and fracture properties so that an appropriate drilling program could be designed and an estimate of recovery could be calculated.

Figure 3a represents an example earth model showing the distribution of matrix porosity calibrated to seismic acoustic impedance, TOC, brittleness, and the structural framework in which it was built. Figure 3b shows the reservoir model in more detail. Two directions of natural fracturing are present in portions of the model where rocks are most brittle. In this workflow, the earth model becomes the input to a basin modeling exercise to validate the distribution of key rock properties and distribute critical static (from the earth model perspective) fluid properties.

Contribution of the Dynamic Basin Model (Basin-Scale)

Basin modeling concerns the simulation of sedimentation, burial, erosion, uplift, thermal calculation, pressure calculations, diagenesis prediction, etc.—all of the processes acting on rocks and fluids during the development of a sedimentary basin. The modeling process is generally applied to entire basins or large portions of them.

Typical reservoir modeling concerns the present-day description of the rock and fluid properties in the subsurface in a highly localized area, with no means to calculate or describe the events by which the reservoir arrived at this state. This article describes a workflow for performing "basin" modeling at the reservoir scale, providing a link between present-day and the historical process that acted on the rocks and fluids.

Workflow

The basic workflow is as follows (Figure 4)**:**
1. Build a detailed, high-resolution earth model that captures the geometry and architecture of the reservoir (e.g., Figure 3).
2. Model the burial history of the reservoir using classical basin modeling techniques.
3. Apply the burial history to the reservoir model to calculate both the rock and the petroleum fluid properties through time.
4. Calibrate against present-day observed data and map dynamic basin simulation results to the static reservoir model.
5. Use the rock and fluid data to identify sweet-spots, perform well planning, and initialize reservoir production simulators.

Building the Reservoir and Basin Models and Applying the Burial History

The first step is to use classical reservoir modeling techniques to build a high-resolution, present-day, accurate description of the reservoir's geometries and properties, as discussed in the previous section. In parallel with this, a basin modeling study is performed over the corresponding area. If the area is relatively small, such that thermal, pressure, and other effects are more or less uniform over the study area, then a one-dimensional (1D) basin model might be sufficient. If the basin processes vary significantly over the area, a 3D study is warranted.

The primary objective of the basin modeling study is to determine the burial history of the reservoir; specifically, its pressure (stress) and temperature histories. When both studies are completed, the burial history information from the basin study can be applied to the reservoir model. To accomplish this, the reservoir structural model is assumed to be correct and fixed. A temperature gradient and overburden (the volume of rock above the reservoir) must be determined. The objective of this step is to provide both rock and fluid properties, through time, and ideally arrive at a solution that calibrates to present-day conditions. Miscalibrations, or difficulties in calibrating, can indicate weaknesses in the initial earth model, suggesting either inaccuracies in its structural framework or in the distribution of static petrophysical or mechanical properties.

The effective stress, temperature, and other properties derived from the basin model are applied to the reservoir grid. The basin

model provides these properties for a number of discrete time points in the past. The output of this process is the through-time representation of the rock properties on the reservoir at the resolution of the original earth model. At this point, geomechanical and other production-evaluation-oriented rock properties can also be calculated from the same process.

Applying the Burial History to the Reservoir Model to Derive Fluid Properties

As important as the rock properties are in validating a static earth model and preparing it for flow simulation, the distribution of petroleum fluid properties, included in the output of this workflow, are arguably more important because they address the fundamental economic basis of the oil and gas industry. In the same way that each element in the model was assigned a lithology ID (Figure 5) that led to the calculation of rock properties, a source type ID is also assigned to each element in the model to calculate source fluid properties. It is linked to source property calculators that include kinetic information on the kerogen types, adsorbed gas, and other in-situ fluid and rock-fluid reactions that occur within the source rock reservoir through time. By applying the burial (temperature) history (Figure 6) to the model, the sediment and source maturities (e.g., Ro) of expelled and adsorbed masses can be calculated. The masses of the fluid components can then be combined with the historical pressure and temperature information to provide pressure, volume, temperature (PVT) -based fluid properties. These would include phase state (liquid/vapor), fluid densities, and fluid viscosities.

Calibration and Sweet-Spot Identification

The outputs of both the static (reservoir) and the dynamic (basin) calculations are compared with observed data, and the processes are iterated, as necessary, to minimize the difference between modeled and observed conditions. The end results of this workflow are a suite of both rock and fluid properties described at the resolution and scale of the original reservoir model. Combined (Figure 7), this can provide a comprehensive set of properties not only to prepare the static reservoir model for dynamic simulation, but also for well planning (Figure 8). Additionally, "sweet-spots" can be determined based on a combined set of rock and fluid properties, including adsorbed gas, geomechanical properties, proximity to existing infrastructure, hydrocarbon state, hydrocarbon quality, rock brittleness, natural fracture distribution, and more, further contributing to drilling and completions strategies.

Summary and Conclusions

The understanding and modeling of unconventional reservoirs is one of the major challenges of this decade. While such

resources have the capacity to dramatically change the balance of energy independence globally, identifying precisely how they work and how they can best be commercially exploited is still unclear. Applying earth modeling workflows from conventional plays is a start, but the distribution of static properties, including petrophysical and mechanical properties, is not always sufficient for shale rock types that were previously believed to be homogeneous. A great deal more must be learned about "shale" facies and the appropriate scale at which they must be modeled. Even so, these static properties largely represent matrix porosities, but many of these source reservoirs are naturally fractured, a property for which direct measurements are sparse, at best. This, combined with stimulation and the interaction between the induced and natural fractures, makes modeling and updating models a challenge.

Understanding the burial history of the reservoir is a step forward in modeling unconventional resources. By integrating the burial history at this detailed level, this work suggests that static reservoir properties can be calibrated and validated; furthermore, the quality, distribution, and state of fluid properties can be assessed in preparation for dynamic simulation, well planning, and drilling. As part of a complete workflow from static modeling to dynamic modeling through production, an understanding the through-time history of the reservoir will provide a more solid foundation upon which to build a knowledge base for better drilling programs and economic forecasting.

References Cited

Chorn, L., J.M. Yarus, S. del Rosario-Davis, and J. Pitcher, 2013, Identification of shale sweet spots using key property estimates from log analysis and geostatistics: SEG Global Meeting Abstracts, L. Baez, K. Beeney, and S. Sonnenberg, eds., Society of Exploration Geophysicists.

Yarus, J.M., and R.L. Chambers, 2006, Practical geostatistics—An armchair overview for petroleum reservoir engineers: Journal of Petroleum Technology, v. 58/11, p. 78–88.
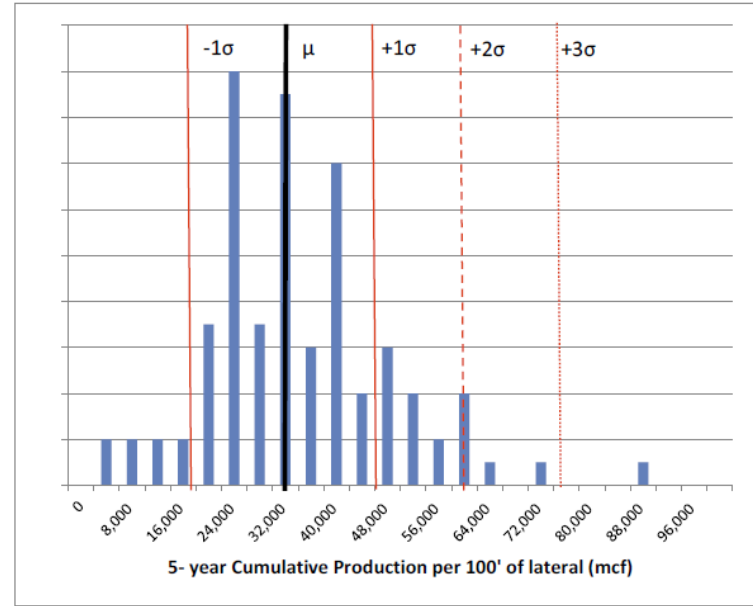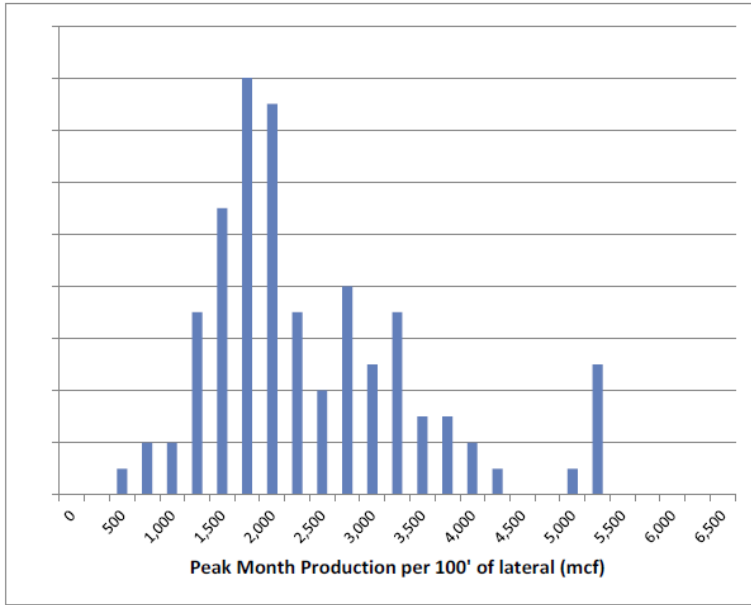
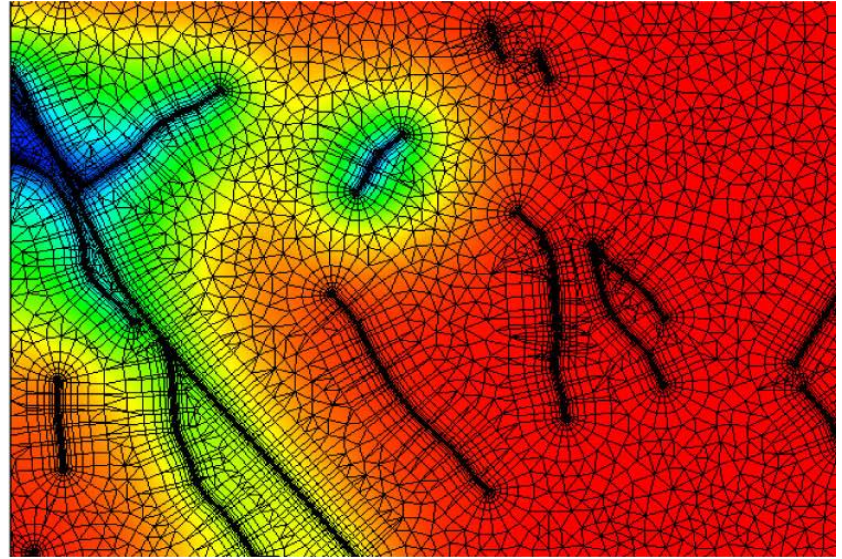Figure 1. Variability in well performance from the Barnett shale (from Chorn et al. 2013).
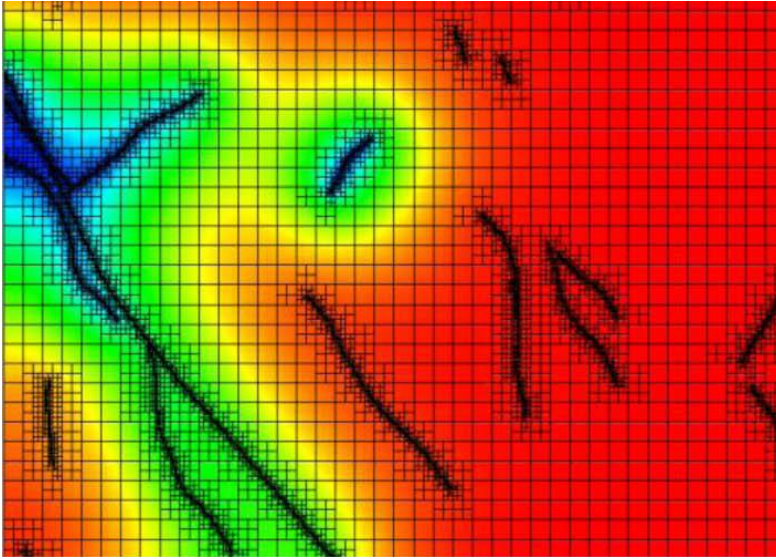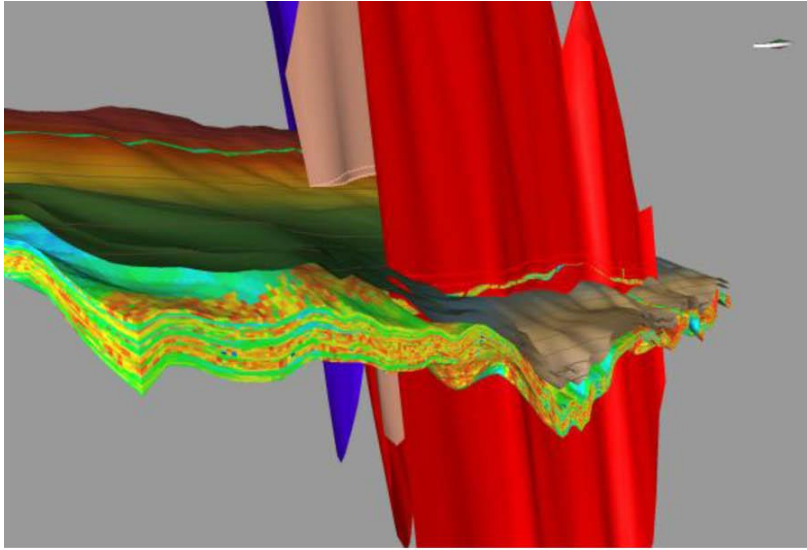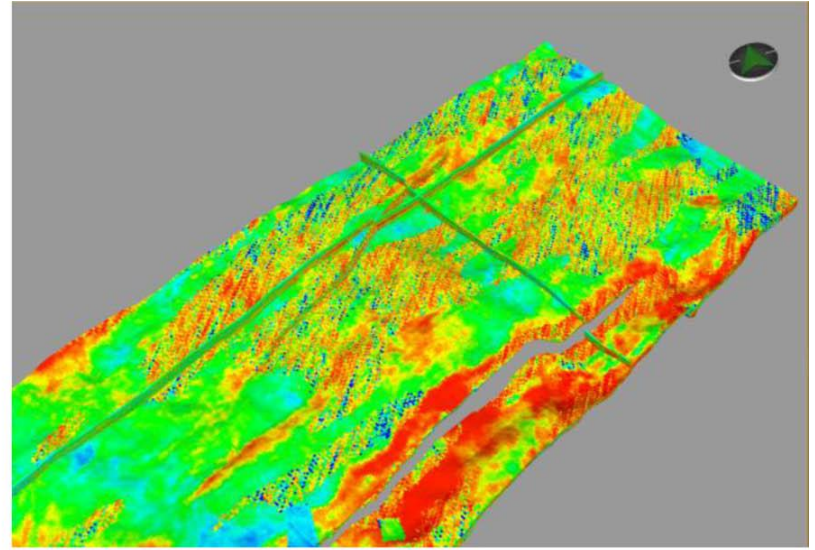
Figure 2. A (left). Simple CDFN showing pressure in a structured regular structured grid. B (right). Simple CDFN showing pressure in an unstructured grid.

(a)   **(b)**

Figure 3. Two views of a 3D Geocellular earth model showing the framework and distribution of matrix porosity calibrated to acoustic impedance, porosity, and TOC. The model serves as input into a thermal-maturation burial-history workflow.
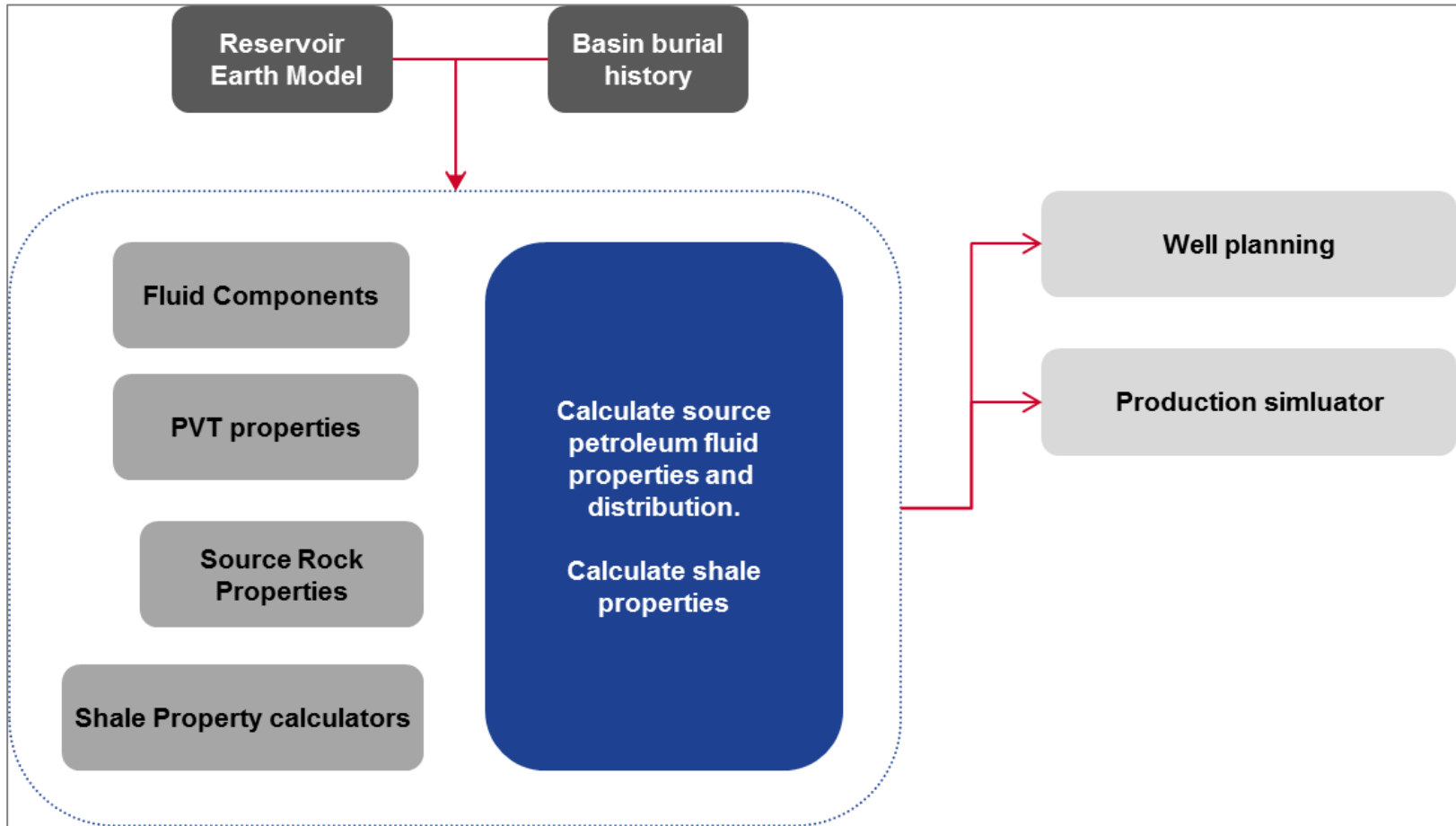
Figure 4. Basic workflow for calibrating a 3D reservoir earth model with a thermal-maturation burial-history model.
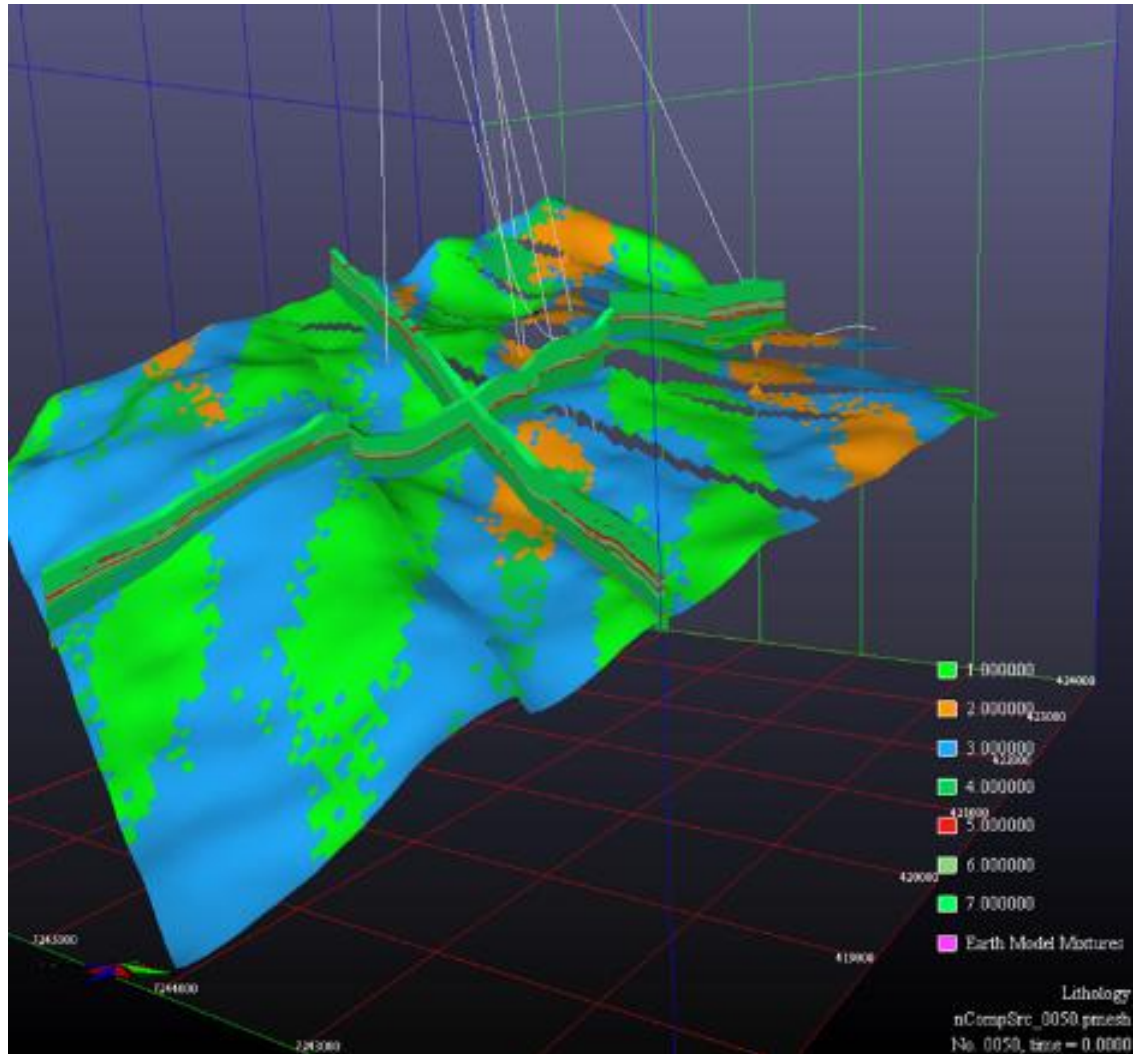
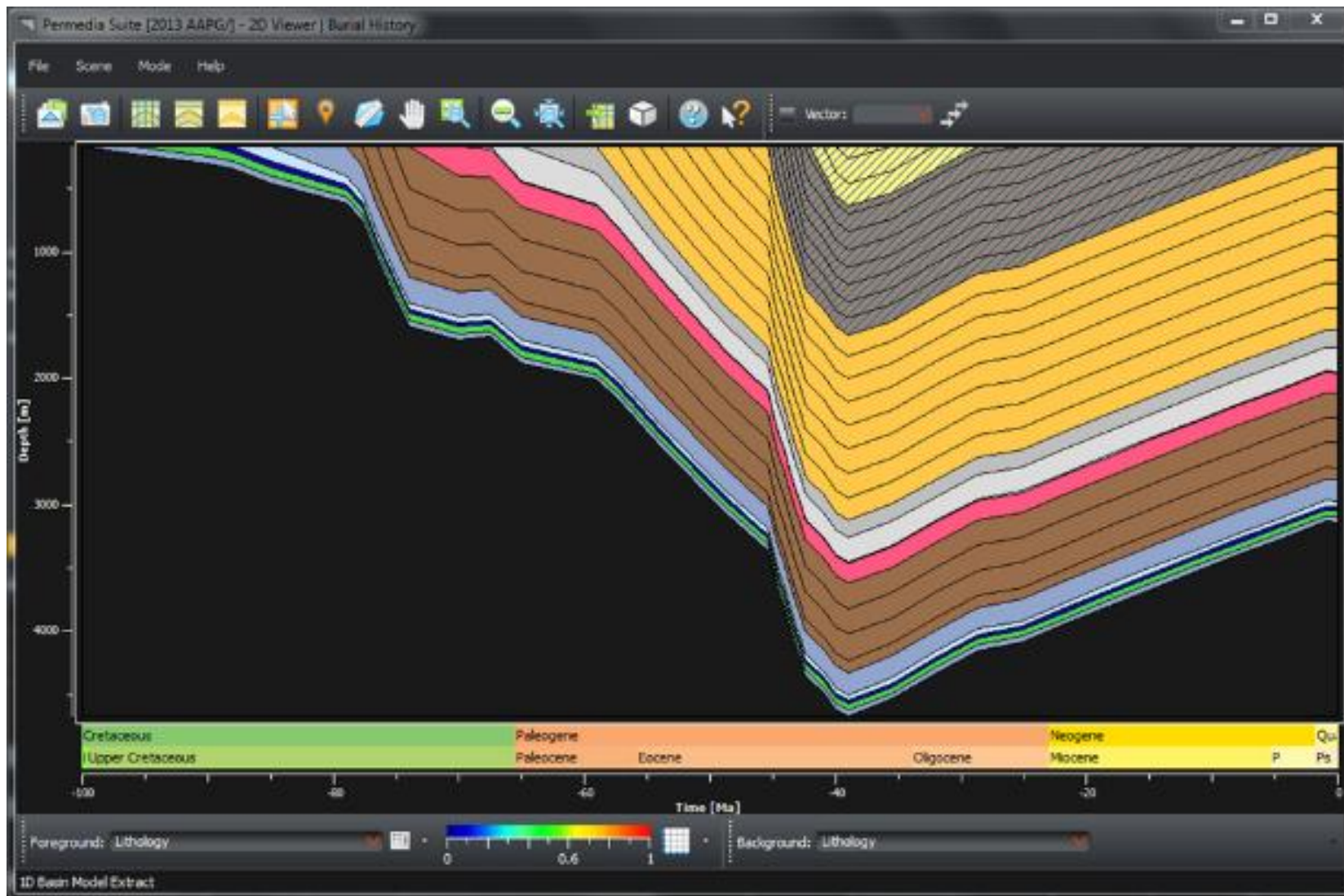Figure 5. 3D Earth model showing distribution of lithologies.
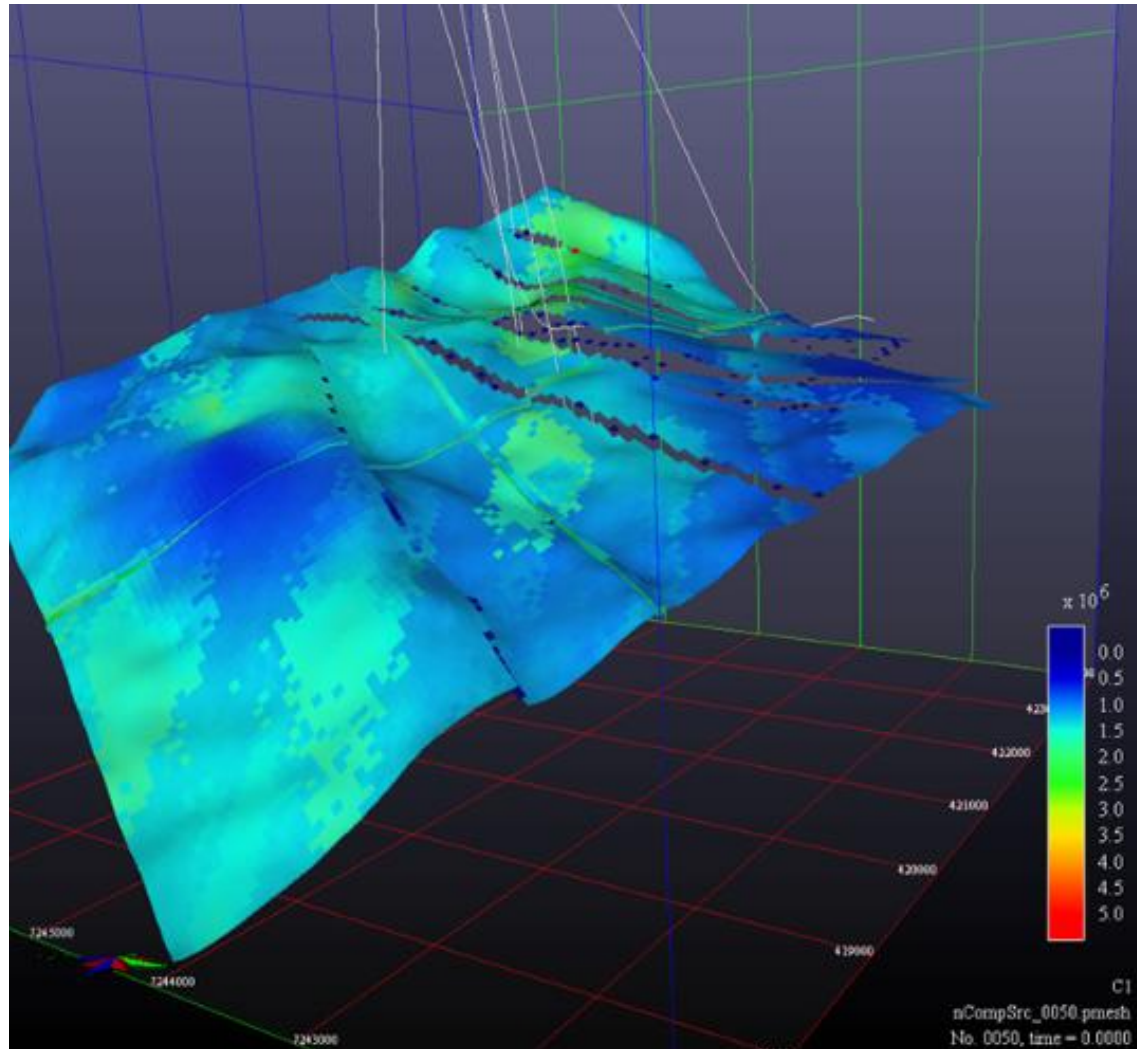
Figure 6. Burial history from Basin model.

Figure 7. Fluid properties, such as expelled and adsorbed component masses and PVT information, are available by combining static and dynamic workflows.
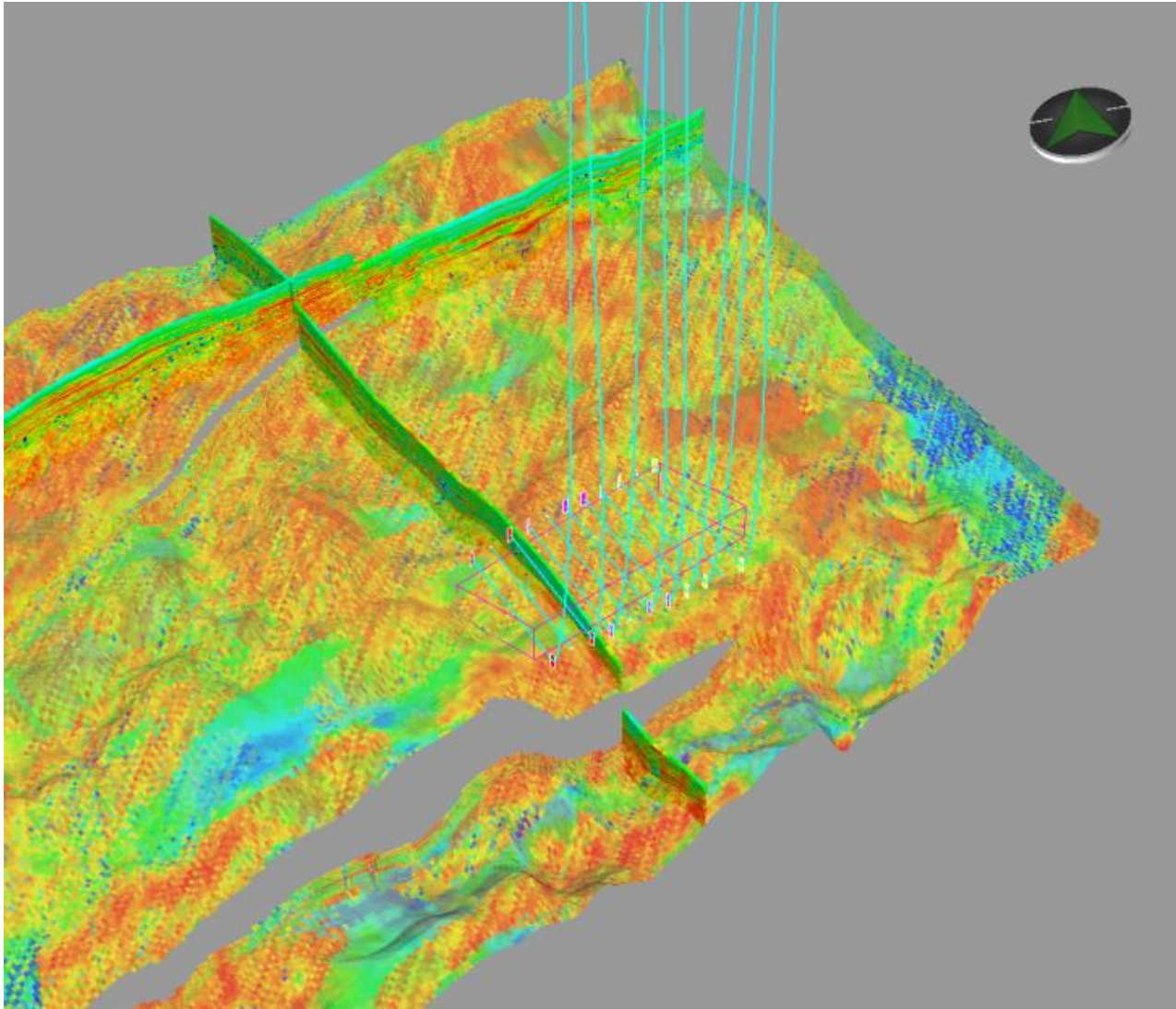
Figure 8. Geocellular earth model showing the distribution of shale quality and initial well design.