Completion Optimization in Barnett Shale Using Drilling Data for a Geologically and Geomechanically Constrained 3D Frac Simulator and Fast Reservoir Simulation*

R. Dirksen[1], S. Poludasu[2], D. Fairchild[2], S. Rehman[2], and A. Ouenes[2]

Search and Discovery Article #42306 (2018)**
Posted October 29, 2018

*Manuscript received July 24, 2018; revised manuscript accepted October 5, 2018.

[1]RigMinder, The Woodlands, TX
[2]FracGeo, The Woodlands, TX (schand@fracgeo.com)

Introduction

Modeling unconventional reservoirs requires increasingly complex physics to capture and describe the phenomena that affect the performance and efficiency of wells. This presupposes sufficient input data to constrain the models. The first shale boom, followed by a collapse in oil prices, incentivized the development of many technologies, especially in the realm of reservoir modeling and simulation, but as new development continues, it becomes increasingly difficult to deploy these technologies without the proper data to drive them. For example, poroelastic geomechanical simulation (Ouenes et al., 2017b) is needed to model frac hits and well interferences resulting from the presence of stress- and pressure-dependent natural fractures and other geologic factors. Recent field observations related to stress relaxation required the introduction of viscoelasticity (Peterson et al., 2018) to better understand the effect of timing during fracing. Lately, the importance of interfaces and their impact on fracture growth required the introduction of 3D damage mechanics (Aimene et al., 2018) to model the propagation of hydraulic fractures in a more realistic rock that considers the layering of the various lithologies and the resulting weak interfaces that will in turn interact with natural fractures.

As the physics of unconventional reservoirs becomes more complex, the data available at each well to correctly model that physics is dwindling at an alarming rate. The introduction of the continuum multiscale approach (Ouenes et al. 2017b) and the use of surface drilling data (e.g., torque (T), rate of penetration (ROP), weight on bit (WOB), etc.) provide the unique opportunity to address both the lack of data and the increasingly complex physics. In the absence of wireline logs and seismic, surface drilling data collected at each well is used in different scales ranging from wellbore to reservoir scale. In this process called “Inverse Design and Validation,” the information contained in the surface drilling data is used 1) during the drilling to optimize the landing zone and geosteering, 2) during the design of the completion to geoengineer the stages while accounting for the variability of the rock, and 3) to build 3D models that will allow the correct estimation of petrophysical and geomechanical properties and stresses needed in 3D planar frac simulators as well as fluid-flow simulation. By augmenting publicly available data with drilling data, robust reservoir models can be developed of both geological and geomechanical properties.

Surface Drilling Data and Its Applications in the Unconventional Well Cycle

When using a rigorous workflow that combines multiple disciplines, the information contained in the surface drilling data can be extracted and used in multiple critical stages of the development of an unconventional well. During drilling and immediately afterwards, Ouenes et al. (2017a) and Jacques et al. (2017) have shown the benefits of deriving, in real time, geomechanical logs, pore pressure, stresses, and natural fracture indices and propagating them in 3D for geosteering and planning ahead of the drill bit. The 3D models derived from the drilling-derived logs allow the driller to remain in a tight drilling window dictated by geomechanical properties which will ultimately affect the performance of the stimulation and the resulting production. Paryani et al. (2018a, 2018b) have shown how the drilling-derived logs are used to geoengineer completions and to provide the necessary 3D input to frac simulators. In this case study we shall illustrate how the multiple uses of surface drilling data are used as a basis for an entire 3D modeling effort designed to better understand the stimulated reservoir volume during and after drilling. The unique workflow described in the next sections illustrates how surface drilling data can be used in real time to provide the inputs required by fast physics-based simulation tools to address complex problems. A pad with five Barnett wells is used to illustrate this workflow.

Critical Logs in Every Unconventional Well - Extracting Value from Surface Drilling Data

The Mechanical Specific Energy (MSE) computed from commonly available surface drilling data such as torque (T), rate of penetration (ROP) and weight on bit (WOB) has been widely used to improve drilling efficiency. Most of the recent MSE applications for completion optimization use surface drilling data which do not represent the MSE at the drillbit. The challenge in unconventional wells is how to reduce costly and risky downhole equipment to measure the downhole MSE while ensuring accurate results. The solution is the Corrected Mechanical Specific Energy (CMSE) calculated in real time using the surface drilling data, the wellbore geometry, and drilling equipment parameters to estimate the friction losses along the drill string (Ouenes et al. 2017a). This technology currently deployed across North and South America, the Middle East, and China, uses advanced drilling and wellbore mechanics to estimate the multiple factors that create the frictional losses in real time. Once these losses are correctly estimated, they can be used to correct the MSE measured from surface drilling data. Figure 1 shows GMXSteering web-based interface and the resulting derived logs at two drilling depths. The GMXSteering interface shows the typical input available in any rig (ROP as red curve in Figure 1, RPM as blue curve in Figure 1) that is processed in a unique fashion to estimate pore pressure and stresses as well as the critical geomechanical logs: Young's modulus (YM), Poisson's ratio (PR), shear modulus (G), stress brittleness (STRBRT), porosity (PHI), and natural fractures (FI). Figure 1 upper windows show in the GMXSteering web-based interface the real time evolution of the derived Young's Modulus. Figure 1 lower windows show the comparison between the derived Young's Modulus log at the considered well and the initial 3D model derived by modeling the 3D distribution of the previously derived Young's Modulus logs estimated from the surface drilling data of prior wells drilled in the considered pad.

Although the concepts used to derive the end products shown in Figure 1 appear to be simple, the mechanics to make such accurate predictions are extremely complex. Not accounting for multiple details will result in the inability to make quantitative predictions of these key properties along the wellbore. For those who succeed in modeling all the key aspects affecting the drilling data, a powerful tool will provide the critical geomechanical logs, pore pressure, and stresses at each well drilled in the past, present, or future. Given that all the unconventional wells require stimulation, this common data provides the necessary information to geoengineer the completion and ultimately increase efficiency.

Well-based 3D Modeling Using Geostatistics and Machine Learning – Propagating the Derived Value across the Reservoir Volume

The large number of wells drilled in unconventional assets combined with the estimation of critical mechanical logs at all of the wells provides the unique opportunity to propagate the well information into a 3D reservoir model. Since many companies do not have seismic on their acreage or for cost reasons do not plan to license the existing seismic, these multiple logs derived at all the wells allow the construction of reliable 3D reservoir models. These 3D models (Figure 2) can be estimated in a stratigraphic framework over the area that encompasses all the wells drilled in the pad. In such cases, geostatistics can be used to estimate the distribution of gamma ray, porosity, Young's Modulus, Poisson's Ratio, and shear modulus. However, the pore pressure, minimum stresses, and natural fracture are more complex continuous properties that need to be estimated with neural networks (Jenkins et al., 2009) and other machine learning tools able to capture the complex geologic reasons that control their variability.

One major reason for propagating these rock properties in 3D is to provide that information to the 3D planar frac simulator. To achieve this goal, all the wells drilled in the pad are used together in a large reservoir grid to create the 3D models from which smaller well grids will be extracted around a well. With this approach, all the available well data will be used to improve the 3D distribution of the key properties needed for the 3D planar frac simulator. The other benefit of these derived 3D models will be the estimation of the stress gradients resulting from the interaction between the regional stress and the three sources of perturbation created by the local geology: variable geomechanical properties, pore pressure, and natural fractures all available thanks to the propagation in 3D of the logs derived from surface drilling data.

Interaction between Regional Stresses and Local Geology – Using Reservoir Geomechanics to Estimate Stress and Strain

The propagation of a hydraulic fracture depends largely on the stress gradients present near and beyond the wellbore. The variable geology interacts with the regional stresses and creates these local stress gradients which are modeled and validated with microseismic data, as shown by Aimene and Ouenes (2015). A major geologic factor causing changes in the magnitude and orientation of the local stresses is the natural fracture system. Since the previous section shows how the continuous 3D natural fracture and pore pressure distribution were derived with machine learning tools and how the other rock properties, such as Young's Modulus and Poisson's Ratio, were derived using geostatistical tools, all of the inputs needed for reservoir geomechanics are available.

The first result of the reservoir geomechanics approach described in Aimene and Ouenes (2015) is the differential stress (Figure 3) which could be used as shown in Paryani et al. (2018b) to geoengineer completions. The advantage of using differential stress for geoengineering completions is the ability to consider the complex geology beyond the wellbore. In other words, well centric approaches, such as the one relying entirely on using a reference log derived from surface drilling data, are approximations that work only if the geology is not highly variable around the considered well. If the geology is variable and there is important variability of the geomechanical properties, natural fractures, and pore pressure, then the best approach is to use the derived 3D models as input in the reservoir-geomechanics approach described in Aimene and Ouenes (2015) to estimate the differential stress. In the considered pad, the differential stress computed from surface drilling data (Figure 4 right track) is compared to the one derived from the reservoir geomechanical simulation shown in Figure 3. This comparison shows very strong similarities between the differential stress derived from full reservoir geomechanics (Figure 4 left track) with the one derived from the well centric approach based only on surface drilling data (Figure 4 right track). Both curves indicate the same zones for high differential stress zones where engineered completions are required to overcome earth resistance to hydraulic fracturing. The engineered completion will adjust the stage length and number of clusters according to the derived differential stress as shown in Figure 5. The resulting engineered completion was derived two hours after the well reached TD. The engineered completion will be used to estimate the fracture geometry and pressure depletion.

Constrained 3D Planar Frac Analysis and Resulting EUR and Pressure Depletion

Given the vertical and lateral variability of the key rock properties used as input in a 3D planar frac simulator, it is imperative that the frac simulator has the ability to use an actual 3D distribution of the properties needed for the simulation. In this study because we have both the 3D distribution of the key rock properties derived from the surface drilling data and the 3D planar frac simulator able to use them, this step is straightforward. Using all of the geologic and geomechanical constraints (Figure 2) as inputs in the 3D planar frac simulator, along with the engineered completion (Figure 5) and a considered pumping schedule, the resulting frac geometry along the wellbore (Figure 6A) is derived. Unfortunately, a frac geometry does not provide the necessary input required for the economics, and the well performance needs to be evaluated with other tools

To estimate the well performance and the pressure depletion, the estimated frac geometry is input in the asymmetric linear model to estimate the EUR (Figure 6B) and in the Fast-Marching Method (FMM) simulator described in Ouenes et al. (2017b) and Paryani et al. (2018b). The resulting pressure depletion (Figure 6C) provides the necessary information needed to evaluate the considered completion and pumping schedule and could be used to optimize the SRV in the considered well pad.

The EUR predictions and the FMM depletion results were derived four (4) hours after TD. In other words, what used to take engineers weeks, is now available with more robust methods that could provide the necessary answers just few hours after the well reaches TD.

Conclusions

The use of surface drilling data provides valuable mechanical information along each wellbore. This information includes the estimation of geomechanical logs, pore pressure, stresses, porosity, and natural fractures. These rock properties can be used as inputs in reservoir geomodeling efforts. These 3D reservoir models provide additional value including the use of them in reservoir geomechanics, 3D planar frac design, and reservoir simulation, which could provide few hours after reaching TD valuable information about the well just drilled.

Acknowledgements

The authors would like to thank Mohit Paryani, Bilel Attia, Nick Umholtz, and Shruti Oza for their contribution to this case study.

Selected References

Aimene, Y., and A. Ouenes, 2015, Geomechanical modeling of hydraulic fractures interacting with natural fractures - Validation with microseismic and tracer data from the Marcellus and Eagle Ford: Interpretation, v. 3/3, p. SU71-SU88. doi: 10.1190/INT-2014-0274.1.

Aimene, Y., C. Hammerquist, J. Nairn, and A. Ouenes, 2018, 3D anisotropic damage mechanics for modeling interaction between hydraulic and natural fractures planes in a layered rock - Application to Eagle Ford and Wolfcamp: paper URTeC 2902985, Houston, TX.

Jacques, A., A. Ouenes, R. Dirksen, M. Paryani, S. Rehman, and M. Bari, 2017, Completion optimization while drilling – Geomechanical steering towards fracable rock using corrected mechanical specific energy: paper URTeC 2693870, Austin, TX.

Jenkins, C., A. Ouenes, A. Zellou, and J. Wingard, 2009, Quantifying and predicting naturally fractured reservoir behavior with continuous fracture models: AAPG Bulletin, v., 93/11, p. 1597-1608.

Ouenes, A., R. Dirksen, M. Paryani, S. Rehman, and M. Bari, 2017a, Completion optimization while drilling - Geomechanical steering towards fracable rock for optimal selection of stage spacing and cluster density in unconventional wells: Society of Petroleum Engineers. doi:10.2118/188087-MS.

Ouenes, A., A. Bachir, A. Khodabakhshnejad, and Y. Aimene, 2017b, Geomechanical modeling using poro-elasticity to prevent frac hits and well interferences, First Break, v. 35/7, p. 71-76.

Ouenes, A., D. Almadhun, S. Soza, X. Li, and R. Smaoui, 2018, Using surface drilling data for a geologically and geomechanically constrained 3D planar frac simulator and fast reservoir simulation – Application to engineered completions and well interference prevention: First Break, v. 36/7, p. 51-56.

Paryani, M., R. Smaoui, S. Poludasu, B. Attia, N. Umholtz, I. Ahmed, and A. Ouenes, 2017, Adaptive fracturing to avoid frac hits and interference: A Wolfcamp Shale case study: Society of Petroleum Engineers. doi:10.2118/185044-MS.
.
Paryani, M., D. Sia, B. Mistry, D. Fairchild, and A. Ouenes, 2018a, Real-time completion optimization of fracture treatment using commonly available surface drilling and fracing data: Society of Petroleum Engineers. doi:10.2118/189810-MS.

Paryani, M., A. Bachir, R. Smaoui, N. Umholtz, A. Khodabakhshnejad, and A. Ouenes, 2018b, Engineered completion and well spacing optimization using a geologically and geomechanically constrained 3D planar frac simulator and Fast Marching Method: Application to Eagle Ford: Society of Petroleum Engineers. doi:10.2118/190070-MS.

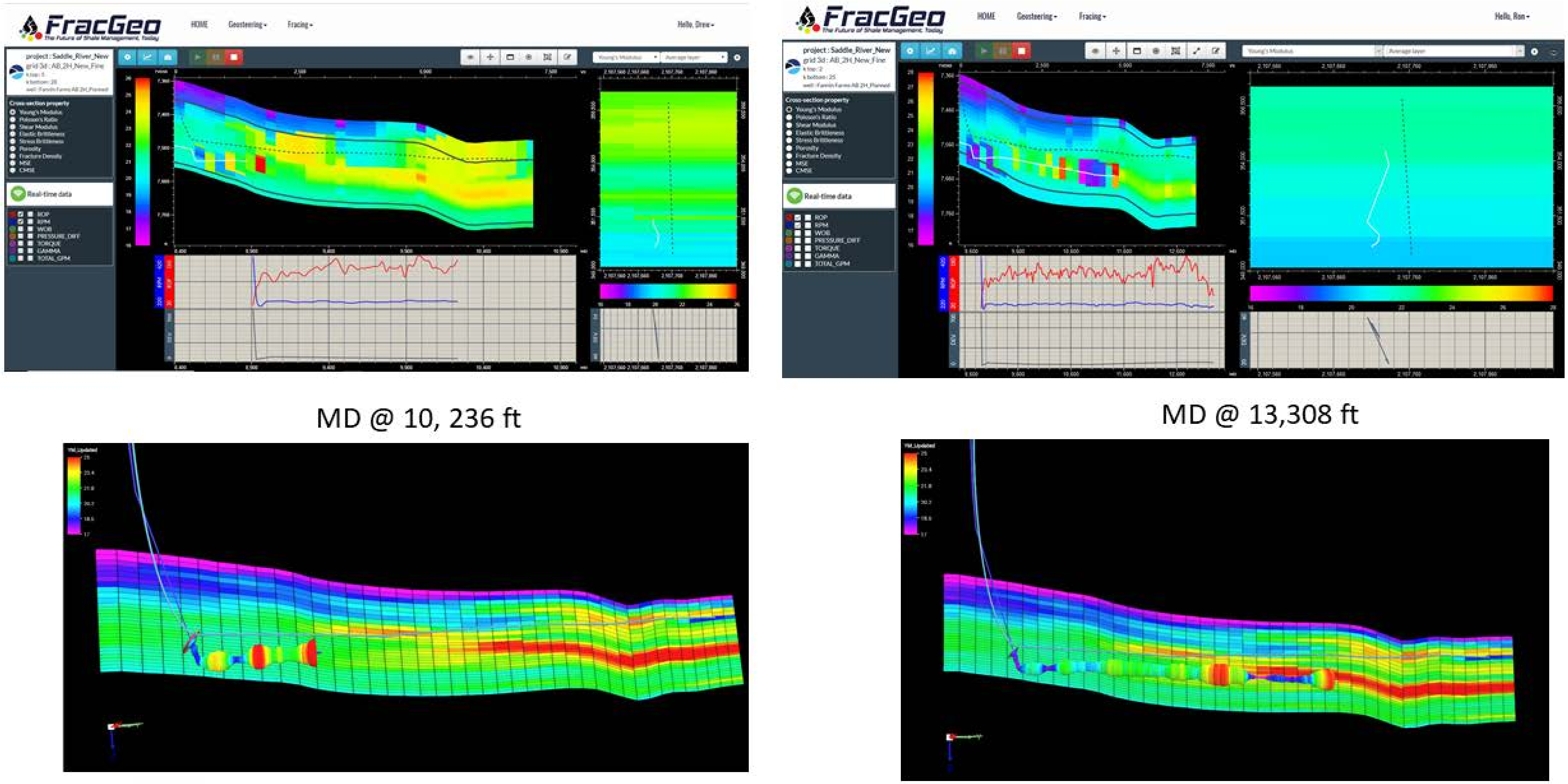


Figure 1. Top windows show the GMXSteering web-based interface at two drilling depths. The interface includes the cross section along the well and the resulting updated 3D model using the derived geomechanical logs that were estimated from surface drilling data such as ROP (red curve) and RPM (blue curve). Bottom windows shows the derived Young's Modulus logs in a cross section showing the initial estimated model.

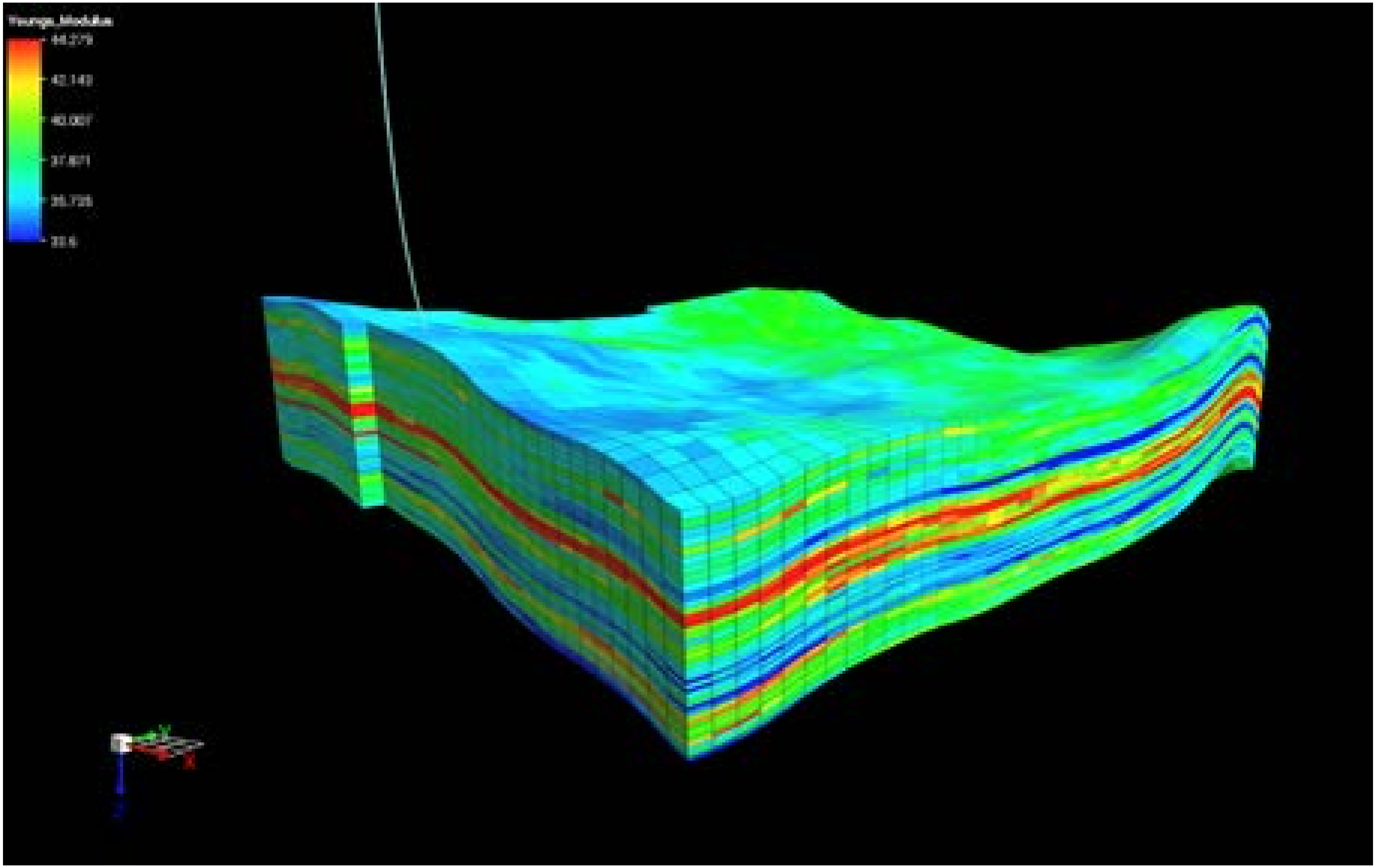


Figure 2. Drilling derived logs are propagated in a 3D geocellular grid each time a new well is drilled.

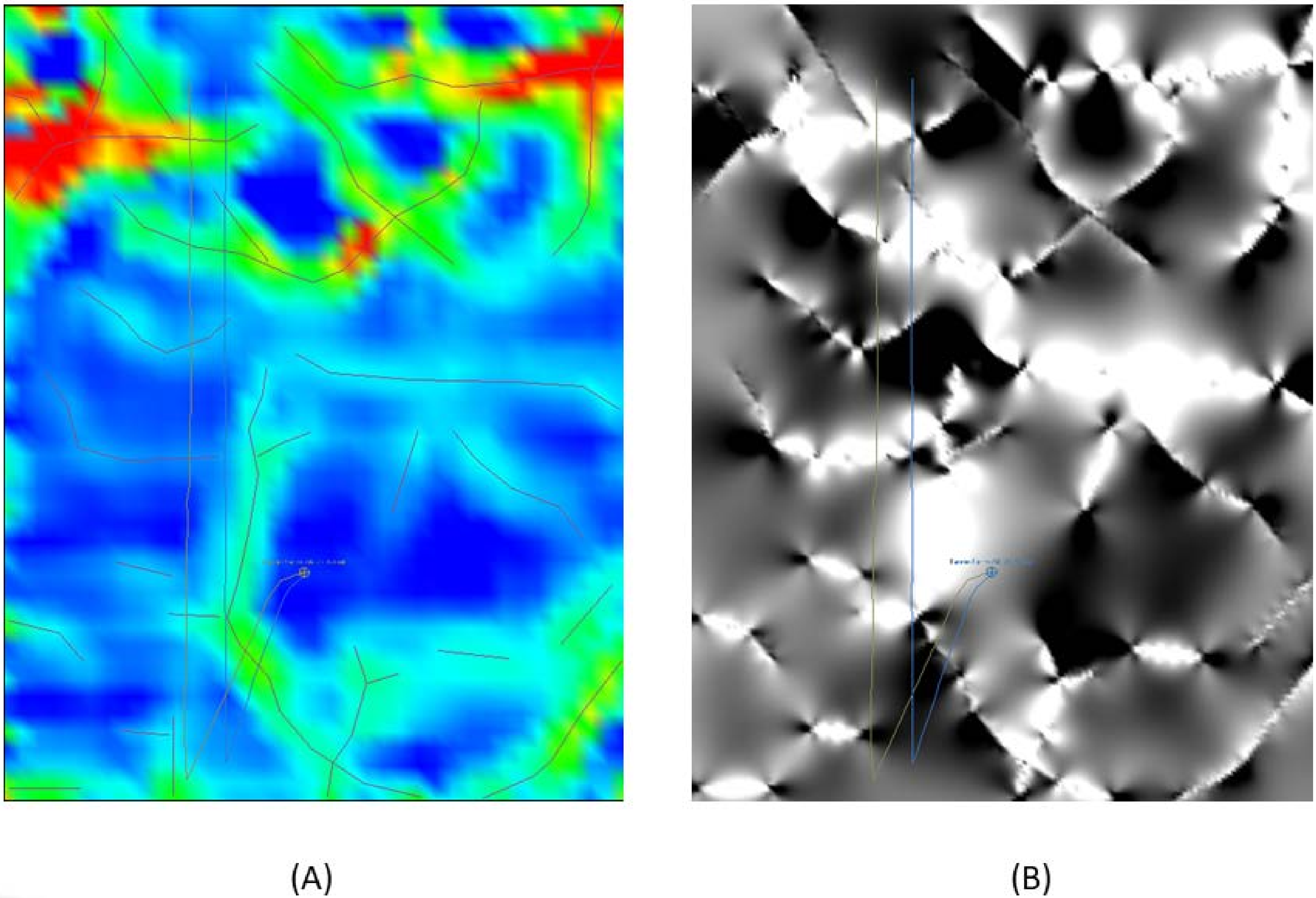


Figure 3. (A) Equivalent Fracture Model (EFM) used as input in the reservoir geomechanics that provides the (B) differential stress which provides the lateral stress gradients needed to geoengineer the stages.

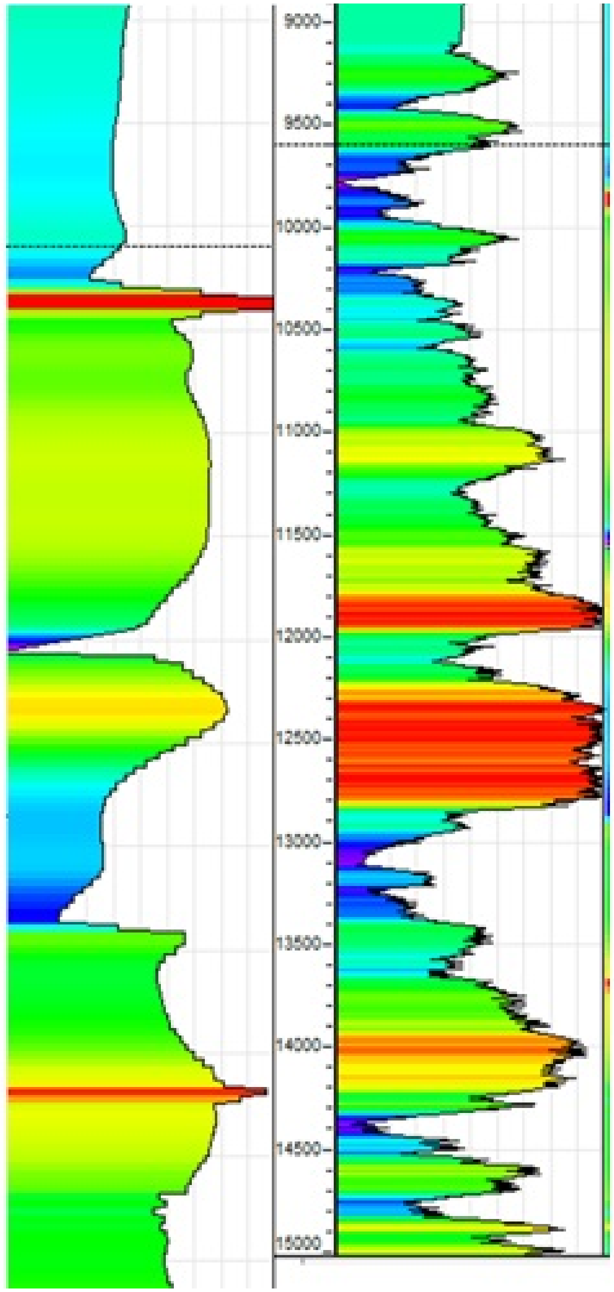
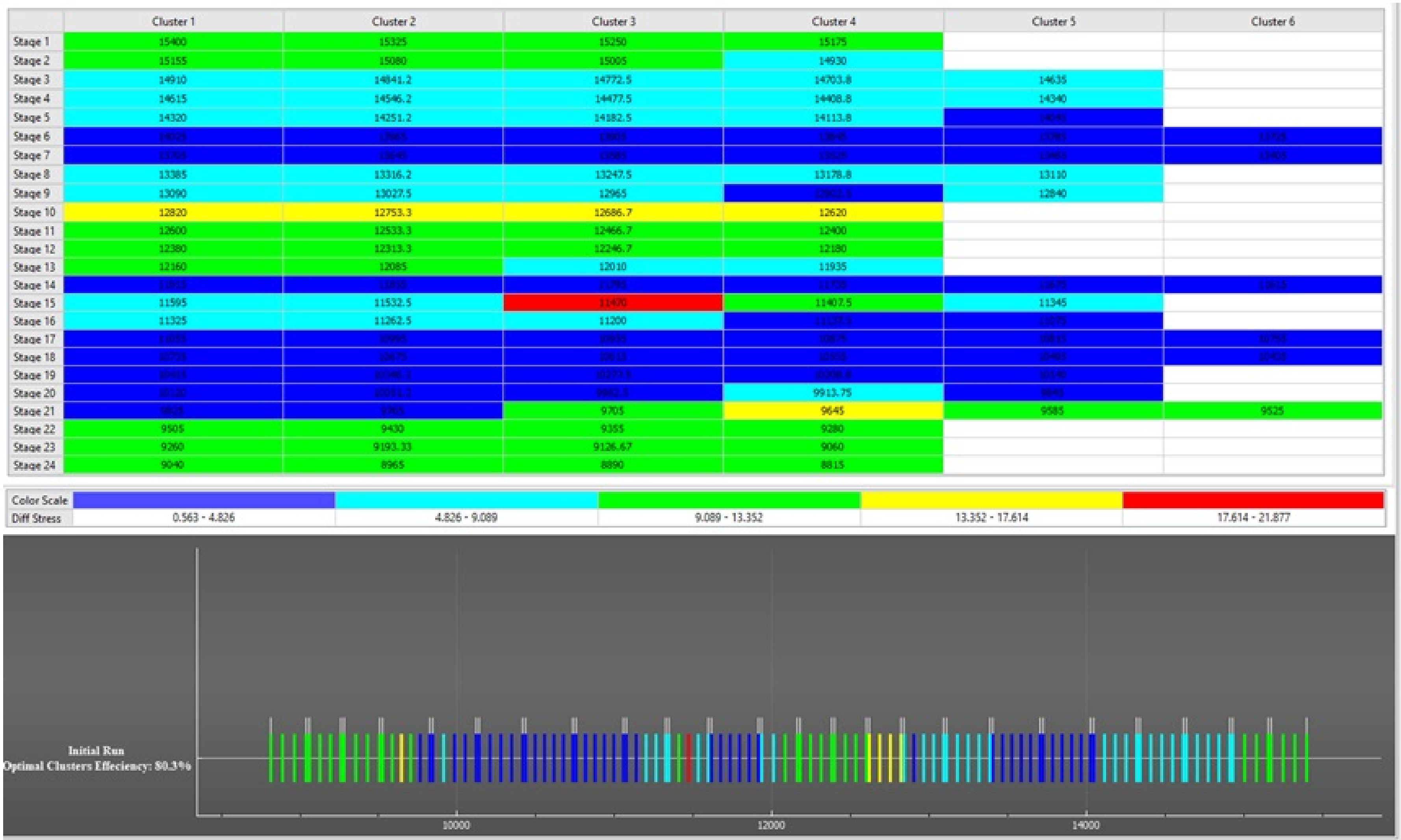


Figure 4. (Left) Differential stress derived from reservoir geomechanics results shown in Figure 3. (Right) differential stress derived from well centric approach using only surface drilling data.



	Cluster 1	Cluster 2	Cluster 3	Cluster 4	Cluster 5	Cluster 6
Stage 1	15400	15325	15250	15175		
Stage 2	15155	15080	15005	14930		
Stage 3	14910	14841.2	14772.5	14703.8	14635	
Stage 4	14615	14546.2	14477.5	14408.8	14340	
Stage 5	14320	14251.2	14182.5	14113.8	[illegible]	
Stage 6	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Stage 7	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Stage 8	13385	13316.2	13247.5	13178.8	13110	
Stage 9	13090	13027.5	12965	[illegible]	12840	
Stage 10	12820	12753.3	12686.7	12620		
Stage 11	12600	12533.3	12466.7	12400		
Stage 12	12380	12313.3	12246.7	12180		
Stage 13	12160	12085	12010	11935		
Stage 14	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Stage 15	11595	11532.5	11470	11407.5	11345	
Stage 16	11325	11262.5	11200	[illegible]	[illegible]	
Stage 17	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Stage 18	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Stage 19	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
Stage 20	[illegible]	[illegible]	[illegible]	9913.75	[illegible]	
Stage 21	[illegible]	[illegible]	9705	9645	9585	9525
Stage 22	9505	9430	9355	9280		
Stage 23	9260	9193.33	9126.67	9060		
Stage 24	9040	8965	8890	8815		

Color Scale					
Diff Stress	0.563 - 4.826	4.826 - 9.089	9.089 - 13.352	13.352 - 17.614	17.614 - 21.877

Figure 5. Engineered completion using the differential stress as a reference log to adjust stage length and number of clusters.

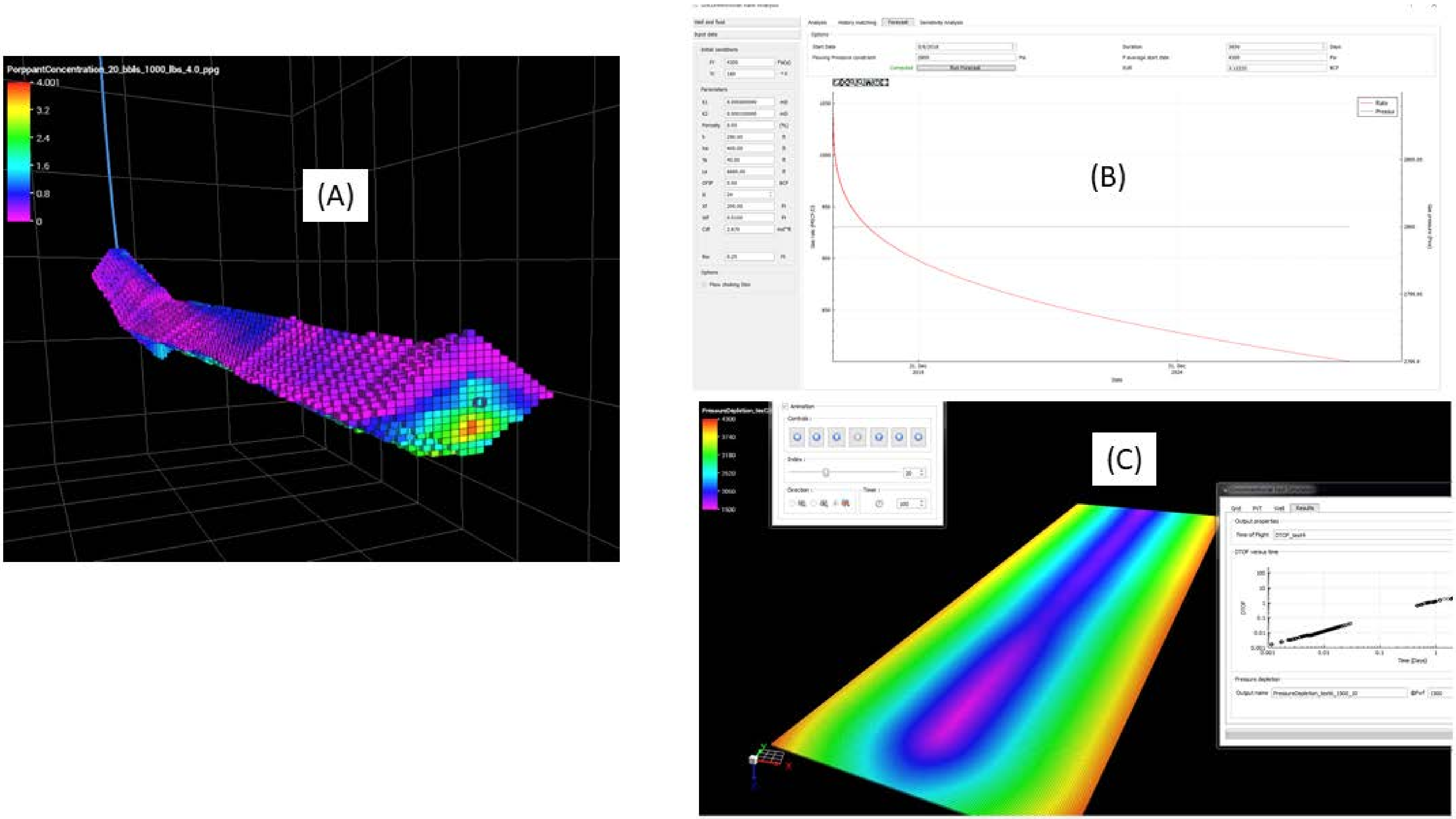


Figure 6. (A) Fracture geometry along the wellbore and (B) resulting EUR and well performance estimated by using the asymmetric tr-linear model. (C) Pressure depletion around the wellbore estimated using the Fast-Marching Method (FMM) simulator.