Enriching Limited Wireline Data with Drilling Data for a Geologically and Geomechanically Constrained 3D Frac Simulator and Fast Reservoir Simulation – A Wolfcamp Midland Basin Case Study

D., Daves[1], D., Thomas[1], B., Lewis[1], N., Umholtz[2], A., Ouenes[2],

[1]: Legacy Reserves, Midland, TX
[2]: FracGeo, The Woodlands, TX

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. Field development, especially in the Permian basin, more and more often prioritizes factory mode drilling and completions over basic data acquisition. Reservoir modeling efforts are plagued by the detrimental impact of these 'data deserts'. It becomes a vicious cycle of poorly constrained models, providing diminishing actionable value, cutting data acquisition budgets, and repeat. 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.

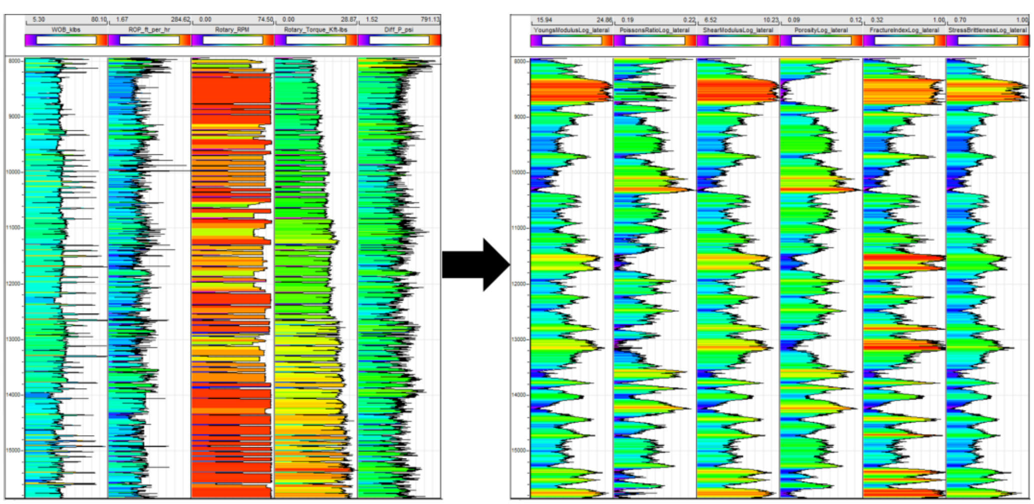
As the physics of unconventional reservoirs becomes more complex, the data available at each well to correctly model that physics is dwindling at an alarming rate. The introduction of the continuum multiscale approach (Ouenes et al. 2017b) and the use of surface drilling data provide the unique opportunity 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, 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 will illustrate the entire "Inverse Design and Validation Process" where multiple wells with only surface drilling data are used as a basis for an entire 3D modeling effort designed to better understand the stimulated reservoir volume of two zipper fraced wells. The unique workflow described in the next sections illustrates how surface drilling data can be transformed to enrich traditional wireline data to provide the inputs required by fast physics-based simulation tools to address complex problems. A pad with two wells in the Midland basin 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. **Fig. 1A** shows the typical input available in any rig: Weight on Bit (WOB), ROP, RPM and Torque 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 (**Fig. 1B**). Although the concepts used to derive the end products shown in **Fig. 1B** 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.



(A) (B)

Figure 1: (A) Using the commonly found surface drilling data to estimate the (B) key geomechanical logs, porosity and natural fractures along any wellbore.

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 can be estimated in a stratigraphic framework over a large area that encompasses many wells (**Fig. 2**). 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.

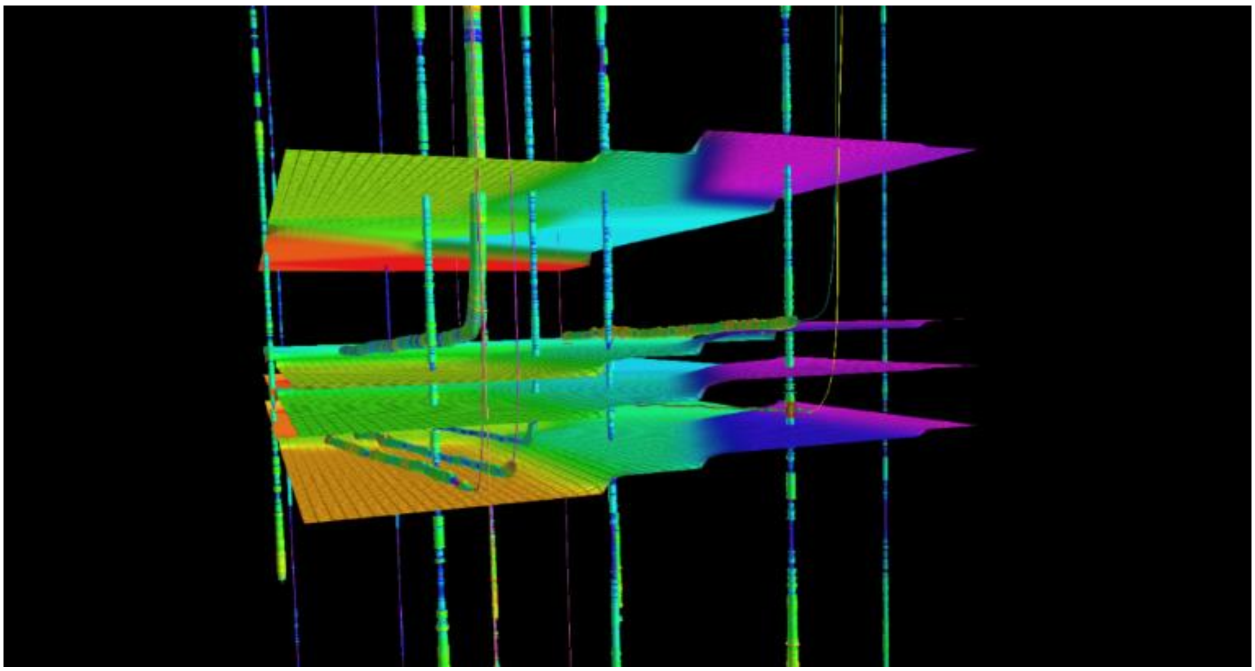


Figure 2: Drilling derived and wireline data within a stratigraphic framework to be used for geomodelling.

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 are used together in a large reservoir grid to create the 3D models from which smaller well grids (**Fig. 3A**) will be extracted around a well or a pad. With this approach, all the available well data will be used to improve the 3D distribution of the key properties (**Fig. 3B-F**) 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.

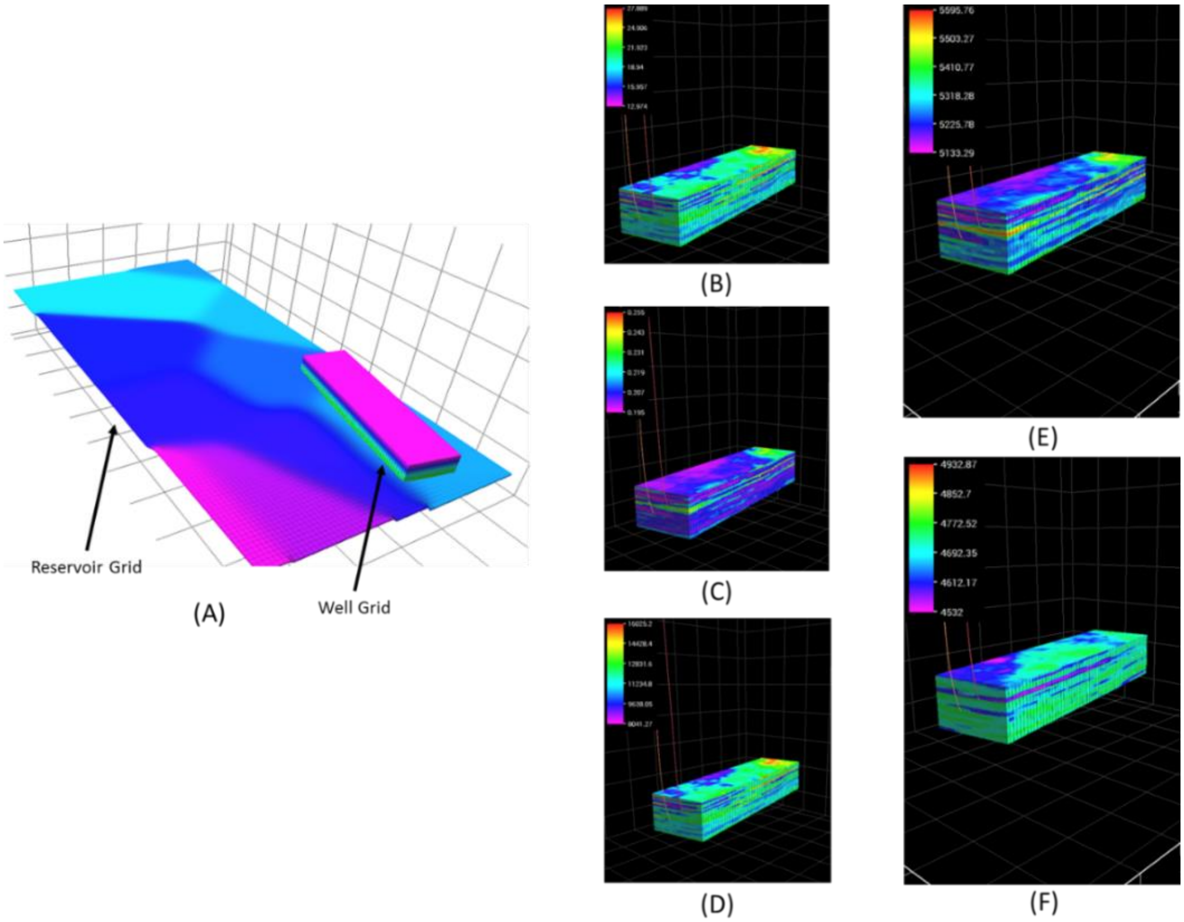


Figure 3: (A) Using all the available wells a large stratigraphic 3D geocellular grid is used to build all the 3D reservoir models from which a well grid will be extracted to provide to the 3D planar frac simulator a 3D distribution of (B) Young's modulus, (C) Poisson's ratio, (D) unconfined compressive strength (UCS), (E) minimum stress. and (F) pore pressure shows the lateral and vertical variability captured by the 3D models and provided to the 3D planar frac simulator

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 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.

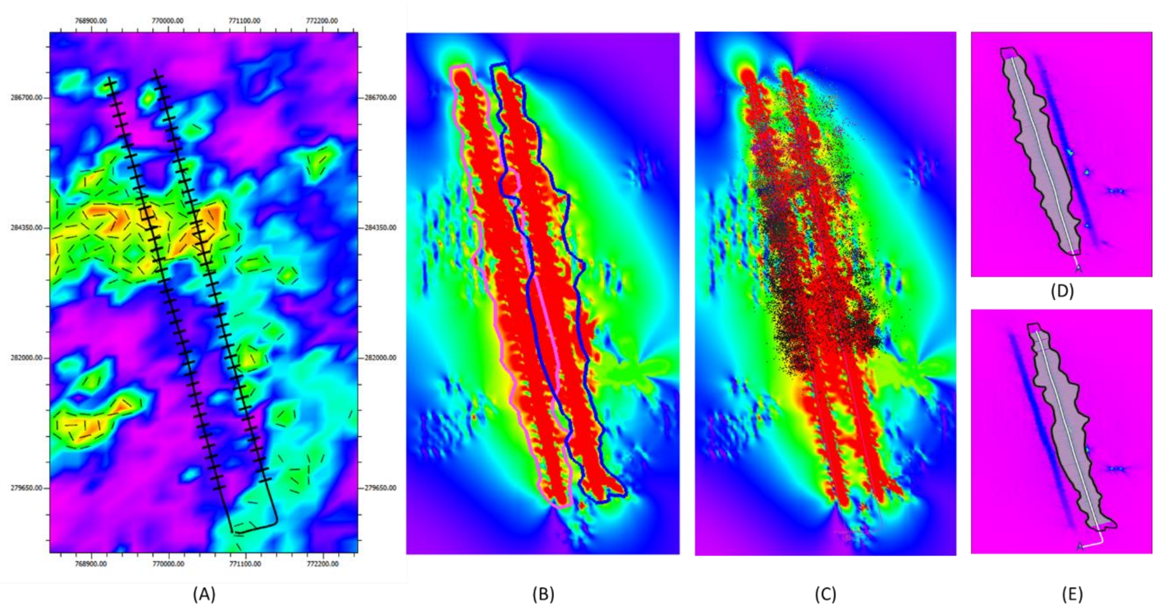


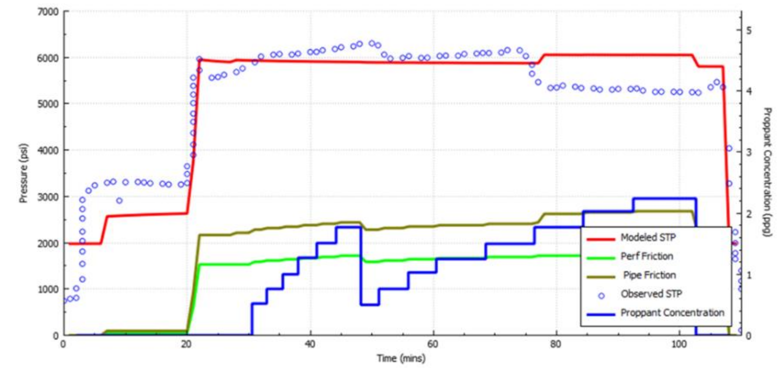
Figure 4: (A) Equivalent Fracture Model (EFM) used as input in the reservoir geomechanics that provides the initial perturbed stress field and the subsequent (B) asymmetric strain resulting from the fracing of the wells and (C) comparison to microseismic (note: the heel section of the wells was not monitored due to operations). (D) and (E) The envelope of strain provides the gross geomechanical half lengths which provide the lateral stress gradients needed to constrain the 3D frac simulator

The first result of the reservoir geomechanics approach described in Aimene and Ouenes is the differential stress 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. Field examples from the Wolfcamp shown in Paryani et al. (2017) demonstrated that the resulting differential stress, validated with microseismic data, captures the variable stress field around the well. Hence, when applying the pressure on the hydraulic fracture faces to simulate the fracing process, the resulting strain (**Fig. 4B**) captures the asymmetric deformation caused by hydraulic fracturing as confirmed by the ability to predict microseismicity (Aimene and Ouenes, 2015, Paryani et al., 2017). Using these validated strain models (**Fig. 4C**), the gross geomechanical half lengths derived from the strain envelope (**Fig. 4D,E**) could be estimated and used as a constraint in the 3D planar frac simulator which will discretize the volumetric SRV captured in the strain shown in **Fig. 4B**.

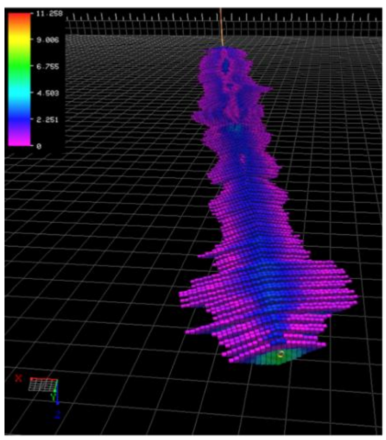
Constrained 3D planar frac analysis

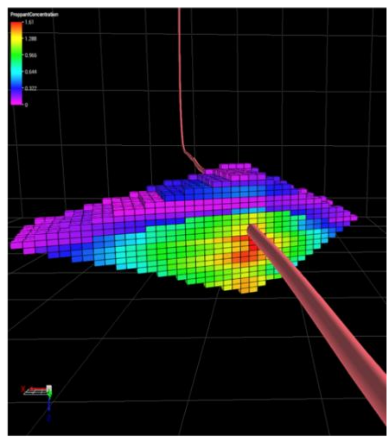
Given the vertical and lateral variability of the key rock properties used as input in a 3D planar frac simulator (**Figs. 3B-F**), it is imperative that the frac simulator has the ability to use an actual 3D distribution of the properties needed for the simulation. In this study because we have both 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. Additionally, the geomechanical half lengths capturing the lateral stress gradients (**Fig. 4D,E**) are used as constraints ensuring a reasonable estimate of the fracture heights. Using all of these constraints as inputs in the 3D planar frac simulator, the pressure during fracing is easily matched

(**Fig. 5A**) by altering only the pipe and perf friction and the leakoff coefficient which depends on the input porosity or natural fracture model. The resulting frac geometry along the wellbore (**Fig. 5B**) or at one stage (**Fig. 5C**) shows the major lateral and vertical variations due to the variable nature of the rock properties captured by the surface drilling data and reservoir modeling efforts. With this result at each well, we have all what is needed for the reservoir simulation.



(A)





(B) (C)

Figure 5: (A) Pressure match at stage 20 and resulting (B) complex fracture geometry and conductivity along the wellbore with major lateral and vertical variations due to the variable nature of the rock properties captured by the surface drilling data and (C) at each stage.

Fast Marching Method for the evaluation of well interference – using the derived value to optimize NPV

The motivation and the unique features of the Fast-Marching Method (FMM) simulator used in this study were described in Ouenes et al. (2017b) and Paryani et al. (2018b). The 3D models and frac geometry derived in the previous sections were input in the FMM simulator along with the PVT and other input data. Ouenes et al. 2018 has shown that the resulting pressure depletion at the end of the simulation derived from the FMM simulator shows the same features as those seen in the pressure depletion estimated in a classical reservoir simulator. Hence, we use in this project the FMM simulator to examine the pressure distribution both in an aerial view (**Fig. 8A**) as well as a cross-section view as shown in **Fig. 8 B-D**. Notice that along the wellbore there are some areas of overlap of the individual wells stimulated reservoir, and some areas which were not as well stimulated. The benefit of the FMM simulation is that the results were derived in less than one minute. With such a rapid evaluation tool and robust workflow that leverages the multiple constraints derived from the use of surface drilling data, the complex balance between finding the optimal NPV per well or per section could be easily estimated in few days. Using the current industry tools to achieve the same objective will take many months and will have a large uncertainty if limited logs are available and no seismic is available as was the case in this study.

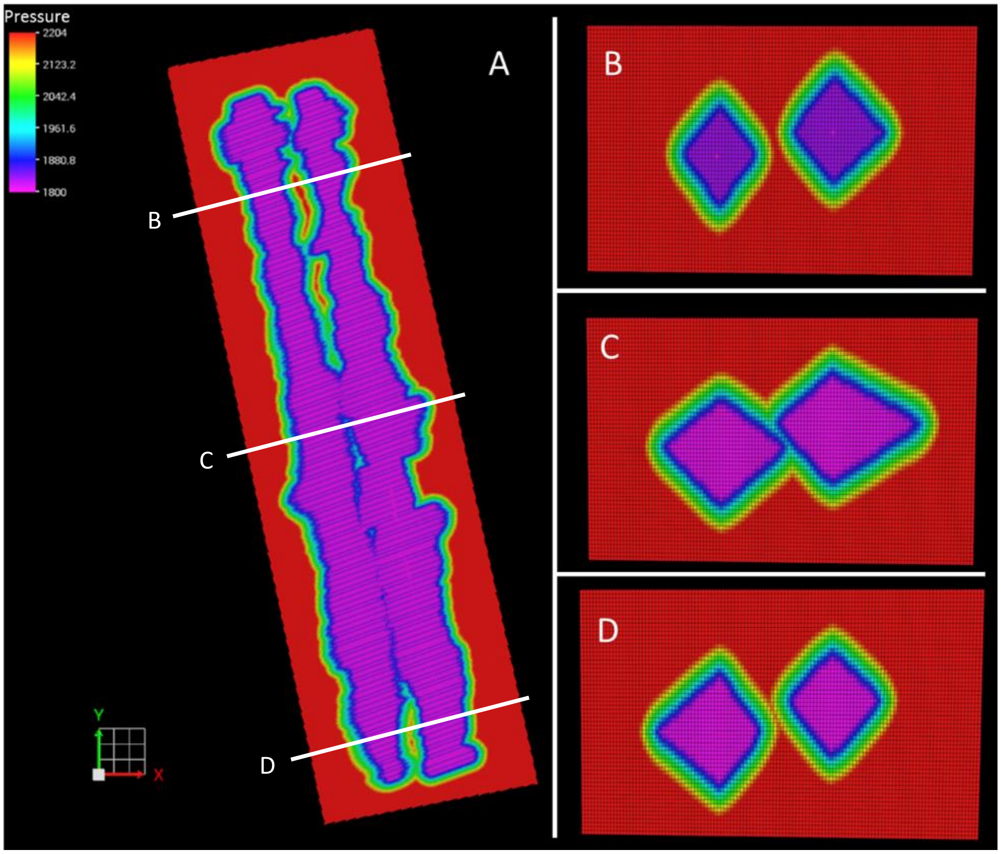


Figure 8: (A) Aerial view of the pressure depletion from the Fast-Marching Method simulator. (B) to (D) shows cross sections illustrating the overlap in some areas as seen in (C).

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 to enrich traditional wireline data in reservoir geomodelling efforts. These 3D reservoir models provide additional value including using them in reservoir geomechanics, 3D planar frac design and reservoir simulation. When using all these 3D models and their results in a Fast Marching Method simulator the impact of the interference between two wells could be estimated quickly while providing similar results as those derived with a classical reservoir simulator. This fast and constrained approach allows the correct estimation of the NPV for each development scenario.

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