

Lectures

Optimization of Hydrocarbon Production from Unconventional Shale Reservoirs using Numerical Modelling

J. Will, S. Eckardt

Optimization of Hydrocarbon Production from Unconventional Shale Reservoirs using Numerical Modelling

J. Will* and S. Eckardt

DYNARDO GmbH, Steubenstraße 25, D-99423 Weimar, Germany

Abstract: The success of unconventional hydrocarbon extraction depends on the effective stimulation of reservoir rocks. Industry practice is to conduct a large number of field trials requiring high capital investment and long cycle-time. The workflow outlined in this paper, using best available reservoir data in combination with best available simulation models offer a cheaper and faster alternative approach for optimization of the complete design and for the improvement of production. Integrating subsurface characteristics, well completion, well operation, diagnostic and well performance analysis by using asset specific data, the development of an optimal completion design is possible. This results in the reduction of field trials, which is primarily necessary for achieving the optimal completion design. In addition, it provides valuable insights for further data acquisition to evaluate and forecast performance of the well.

This paper introduces the workflow to model, calibrate and optimize the landing and orientation of the well including hydraulic fracturing stimulation design for naturally fractured unconventional shale reservoirs. For fracture simulation, the paper introduces an approach for parametric coupled hydro-mechanical 3D Finite Element (FEM) modeling, including non-linear material modeling of fracture propagation in sedimentary rocks. In order to calculate production out of the created fracture network, estimation of accessible connected hydrocarbons is calculated. For calibration and optimization purposes, automated sensitivity studies for uncertainty variations of the reservoir parameters as well as engineering and operational parameters are performed and are evaluated relative to the resulting Stimulated Reservoir Volume (SRV), Accessible Hydrocarbon initially in Place (AHCIP) and Estimated Ultimate Recovery (EUR).

The current version of this technology does not handle proppant transport and placement. Instead, assumptions are made for proppant acceptance in the fracture network and used in estimating the proppant accepting simulated rock volume, connected hydrocarbons, and hydrocarbon production. Further enhancement of the FEM workflow to capture 3D proppant transport and placement is under development and will be a major update in the upcoming hydraulic fracture simulator version.

Keywords: Hydraulic fracturing simulation, model calibration, hydrocarbon production optimization.

1. INTRODUCTION

The essential and the best available simulation technology in combination with the best available measurements and diagnostics is an industrial requisite. Especially in an environment of low oil and gas price, the costs of drilling and completion relative to the resulting production needs to be optimized, while long trial and error cycles to achieve optimal well and stimulation designs are unacceptable.

Why is traditional fracture modelling in oil and gas too limited?

In order to adopt simulation for decision making, the ability of simulated models to represent the driving fundamental physics, which could, in turn, match the available measurements, needs to be proven in the first place. In unconventional reservoirs, everything begins with the generation of the fracture system. Therefore, the simulation process needs to cover the same accurately enough and to be used later in forecasting the production differences out of different wells and completion designs.

Traditional fracture simulators are often limited to the base assumption of generating single (often symmetric) fracture by tensile failure, under isotropic strength conditions perpendicular to the direction of minimum horizontal stress. These underlying assumptions oversimplify the fracturing process in shale's, which are in turn pre-jointed rocks having anisotropic stress and strength conditions and therefore miss the major driving forces of fracture growth in such types of rocks. [6, Wittke: "The failure of matrix rock can be neglected. The failure along joints dominates."]

What does fracture and fracture network generation really drive in oil and gas shales?

Fracture activation and fracture extension during hydraulic fracturing in shale reservoirs are dominated by anisotropic stresses and strengths resulting from loading on the *in situ* patterns of pre-existing joints or pre-existing planes which are weak in strength. These pre-existing joints represent the "strength texture" of shales, having set of oriented strength anisotropies corresponding to open or closed natural joints. Investigation of the jointed rocks on well logs or outcrops, lead to the identification of 3 to 4 such joint sets. When fracturing the rock, the *in situ* anisotropic

*Address correspondence to this author at the DYNARDO GmbH, Steubenstraße 25, D-99423 Weimar, Germany; Tel: +49 3643900830; Fax: ++49 (0)3643 9008-39; E-mail: johannes.will@dynardo.de

strength in combination with *in situ* anisotropic stresses will dictate the activation of a particular fracture system, the direction of the fracture growth and corresponding activation of the failure mode (tensile or shear). Due to stress redirection and stress shadowing, during the process of the multiple fracture growth, the fracture modes, the directions, and the activities may change and single fracture planes starting from the perforations may meet each other and result in the fracture network. In order to capture these effects with fracture mechanics, three-dimensional modeling of anisotropic stresses and strengths of the *in situ* rock together with the anisotropic conductivity of the generated fracture system is required. Any simplification to 2D, 2.5D or pseudo 3D will again lead to oversimplification of the fracture growth.

[4, Weijers: “Hydraulic fracture design models are useful as predictive tools for the optimization of hydraulic fracturing. However, they all suffer from an incomplete understanding of the mechanics of fracture propagation in the formation. Therefore, the two technologies must be combined such that direct physical measurements of the growth of hydraulic fracture can be coupled to a 3D simulator of hydraulic fracturing. This result in a calibrated hydraulic fracturing model. The input parameters to the model, took from the best available well log and reservoir information must be calibrated from the direct diagnostics measurements to assign the correct level of importance to various mechanisms of the containment of the hydraulic fracturing. Only with this degree of diagnostic characterization of the hydraulic fracture and coupled modeling, it is possible to understand truly the controls on the evolution of the geometry of hydraulic fractures. With this integrated approach, a predictive model for the design of hydraulic fracture can be developed for a

reservoir. By use of the predictive calibrated model the stimulation can be optimized to provide the required conductivity and maximum effective length of the hydraulic fracture to maximize the productive economics.”]

Simulating the discrete growth of multiple fractures in 3D is numerically challenging. So far, only a few available homogenized continuum approaches seem to be numerically efficient enough to be used in calibration and optimization studies by preserving the necessary freedom and accuracy to forecast the differences of fracture networks from different wells and completion designs.

The homogenized continuum approach was initially developed and applied in Civil Engineering field to efficiently determine the influence of water flow in naturally fractured rock, like dam foundations [4]. It is improved and generalized for the coupled hydraulic-mechanical, hydraulic fracturing of naturally fractured rocks in the last 15 years by Dynardo GmbH [2,8]. The developments resulted in a FEM-based Thermo-Hydro-Mechanical (THM) simulation environment, used today for hydraulic fracturing in Oil and Gas as well as other fracture related application in rock mechanics like Enhanced Geothermal Systems (EGS) [13] or integrity of nuclear waste disposals [9].

The hydraulic fracturing simulation is based on coupled hydraulic-mechanical analysis using a parametric modelling approach as shown in Figure 1. The parametric modeling approach is a key in forming an interface to the hydraulic fracture simulation and to automatic sensitivity studies, calibration, and optimization workflows. Finally, a single realization of the reservoir well and stimulation conditions starts from

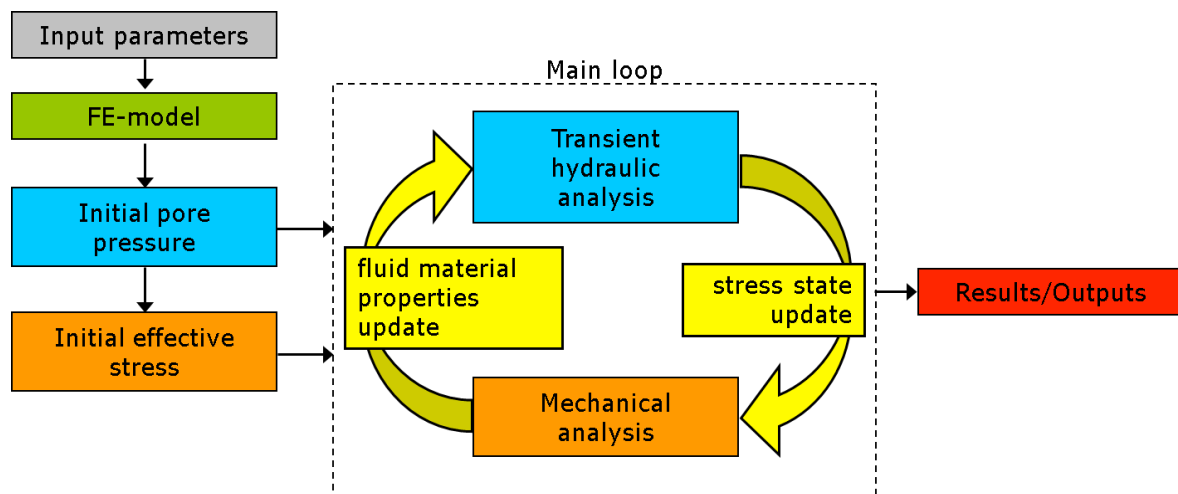


Figure 1: Coupled hydraulic-mechanical fracturing simulation.

a parameter file and ends with multiple response files as a batch simulation run in a fully automatic process.

The main physical phenomena modelled in the fracturing simulator are as listed below:

- i. Non-linear mechanical fracture generation and growth analysis using multi-surface plasticity for modelling fracture networks in jointed rocks within homogenized continuum approach.
- ii. Hydraulic model is based on the assumption of laminar flow in single joint per element or multiple parallel joint systems per element using homogenized continuum approach.
- iii. The mechanical to the hydraulic coupling which involves computation of fracture opening and closure resulting in anisotropic hydraulic jointed rock conductivity covering effects of stimulation and *in situ* fractured rock.
- iv. The hydraulic to the mechanical coupling which involves computation of flow forces, depending on the pressure gradients within the jointed rock.
- v. Very important to realistically simulate the non-linear history of fracture creation and activation is the initialization of anisotropic *in situ* reservoir conditions like initial anisotropic *in situ* strength, stress and isotropic pore pressure conditions for all relevant rock layers within a reservoir.

2. VERIFICATION OF THE HOMOGENIZED CONTINUUM APPROACH FOR HYDRAULIC FRACTURING

To verify the homogenized continuum approach of the hydraulic fracturing, a theoretical solution of a single penny shaped hydraulic fracture in the saturated low permeable medium [5] was recalculated [13]. Figure 2 shows the penny-shaped hydraulic fracture model. It is shown that the homogenized continuum approach along with the discrete joint modelling, the solution using cohesive zone modelling or XFEM approach within the framework of continuum mechanics documented in [5] each case shows good agreement with the analytical solution of the penny-shaped fracture.

Figure 3 shows the joint opening, Figure 4 shows the fluid pressure along the crack of all 4 approaches. Figure 5 shows the (scaled) opening and the stresses around the fracture using the different approaches in a FEM environment.

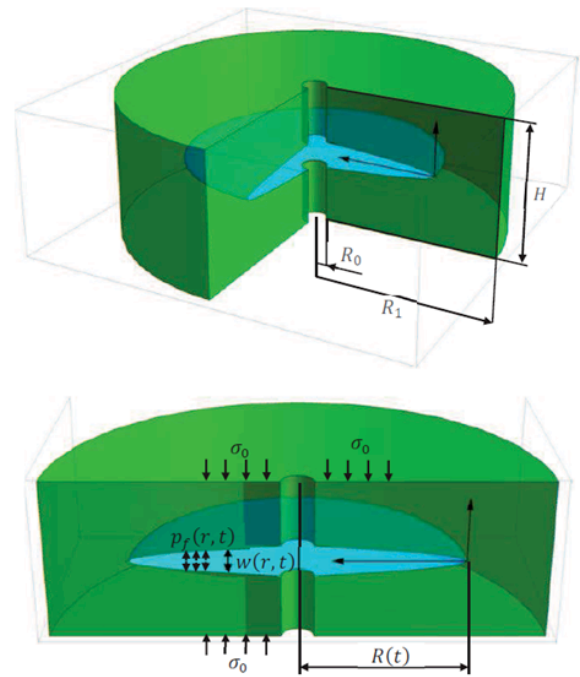


Figure 2: The cylindrical domain showing the horizontal, penny-shaped, hydraulically driven fracture [4].

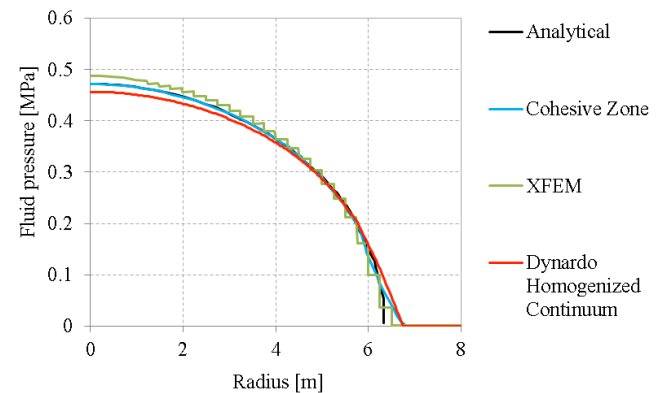


Figure 3: Joint opening along the crack at the end of pumping.

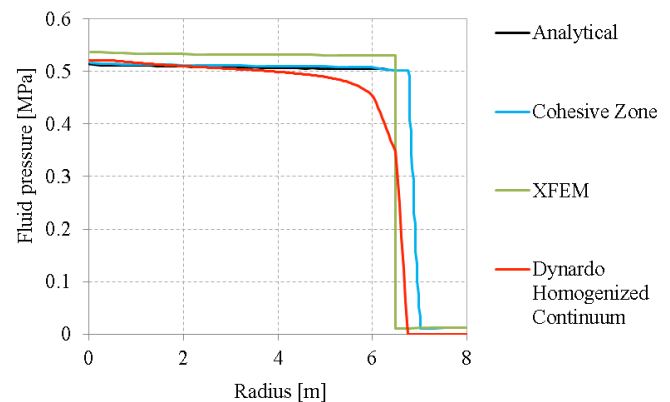
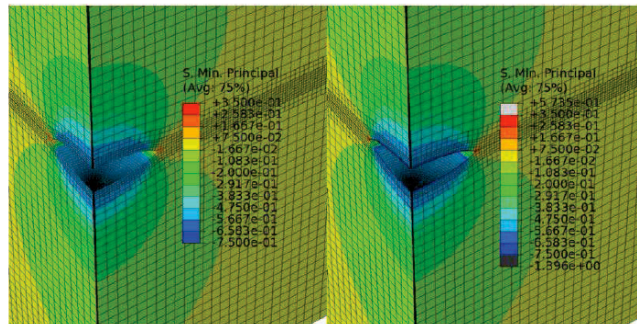


Figure 4: Fluid pressure along the crack at the end of pumping.

Besides the theoretical solution, FEM based discrete modelling using cohesive zone elements and XFEM was verified.

a)



b)

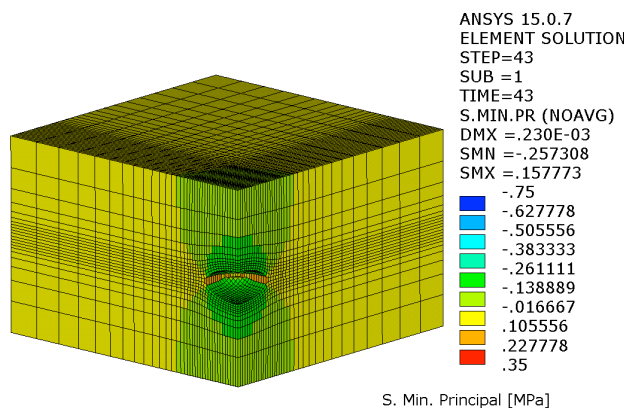


Figure 5: Maximum effective principal stress for models based on a) Cohesive element method (left), XFEM method (right) in [4] and b) Dynardo fracturing simulator.

It should be noted that any strategy which uses a priori definition of the discrete fracture network like cohesive zone elements or discrete fracture network (DFN) modelling based on micro-seismic, suffer on the fact that the result should not become the input. Such modelling is still good enough to produce post processing pictures of created fracture networks and help to understand the phenomena or differences between fracture locations. But to use simulation for optimization of hydraulic fracturing, we need to be able to simulate the difference in fracture networks when we change operational conditions in a forecast mode by a priori defining the fracture location that, very important requirement is missing.

The alternatives to predefine the fracture location, which can be used for the prediction of fracture growth network, are either XFEM, particle modelling methods

or the homogenized continuum approach. But the strategies of discrete modelling of fracture growth in 3D with the possibility of modeling different fracture systems under different operational conditions using XFEM or particle modeling are extremely numerically expensive and applying such strategies for reservoir modelling with multiple stages and multiple wells are not to be foreseeable within next decades. Therefore the homogenized continuum approach today seems to be the only approach available, which can be used to optimize stimulation procedure of unconventional oil and gas reservoirs at stage and well level modelling (with single or multiple wells) using numerical simulation.

3. WORKFLOW TO OPTIMIZE PRODUCTION FOR UNCONVENTIONAL

Figure 6 shows the workflow which was developed for optimization of unconventional. It starts with data collection, to introduce all available data for defining the *in situ* conditions. Followed by parametric model construction, initialization, calibration and sensitivity study to find the variation of operational parameters, and completion design optimization. For parametric modelling and finite element solver, ANSYS [1] is employed. For non-linear coupled fluid-mechanical modeling of naturally fractured rocks and post processing, the Dynardo hydraulic fracturing simulator [2] along with ANSYS is employed. The third software module, optiSLang [3], is employed to automatically calibrate the model and perform sensitivity analyses and fracture design optimization with consideration of variation in subsurface, completion design, and operational parameters.

Since maximization of stimulated rock volume relates accessible hydrocarbons and hydrocarbon production most likely will be in conflict with minimization of stimulation expenses, cost functions need to be further incorporated and so-called “Pareto” optimization needs to be performed. Finally, all fracture designs at the Pareto Frontier (Figure 7) represent designs which show optimal production with relative costs. Having these Pareto Frontier for a reservoir is the final and most valuable outcome of the workflow and forms the basis to discuss and take decisions.

3.1. Calibration

As a matter of fact the reservoir data have a lot of uncertainties. Therefore the calibration of the reservoir conditions to the available measurements becomes a

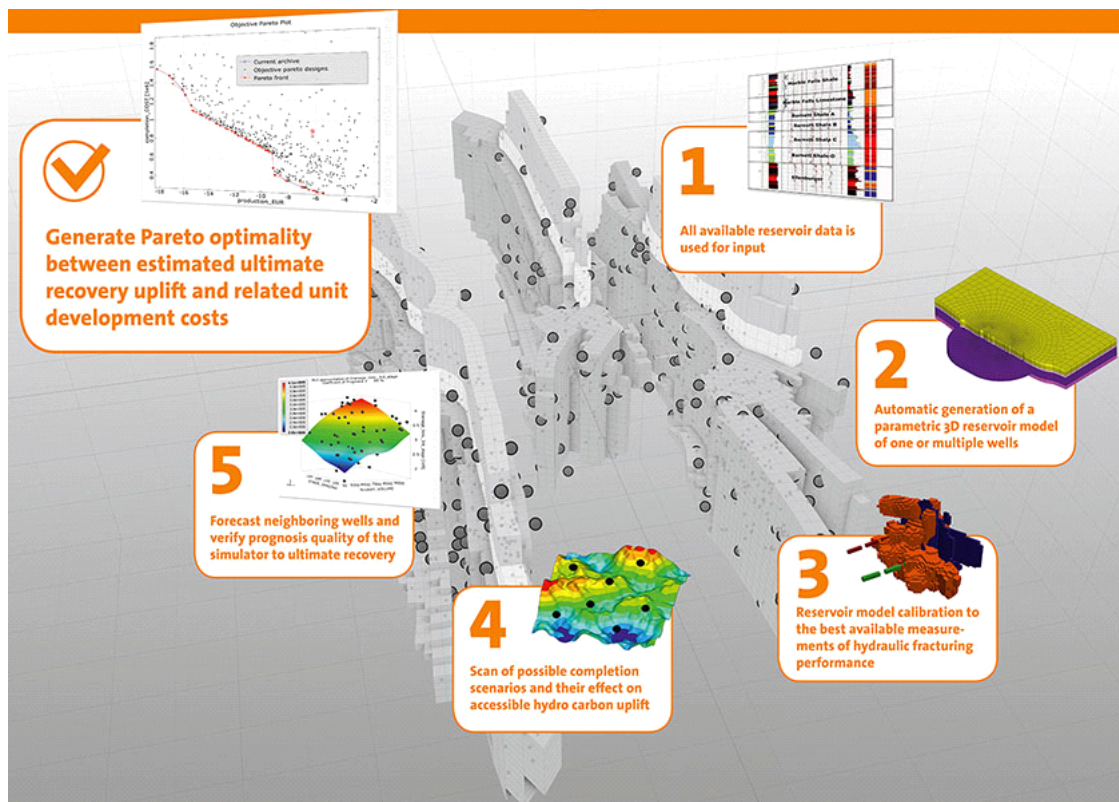


Figure 6: Dynardo workflow for hydraulic fracturing simulation and completion optimization.

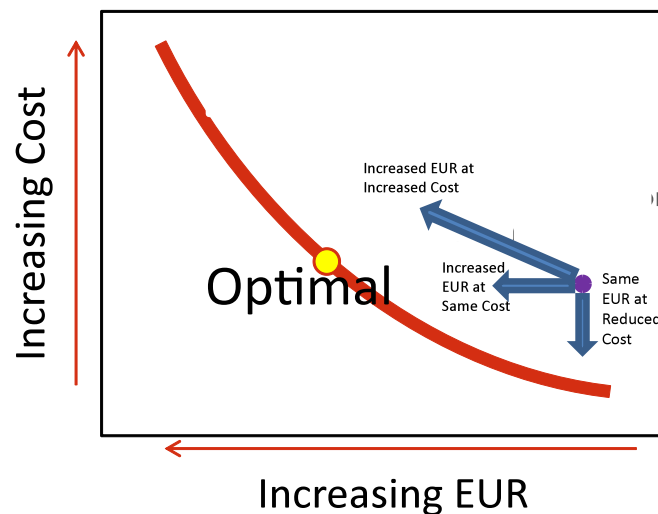


Figure 7: Pareto Plot between EUR and Costs (UDC).

very important part of the workflow and a crucial part of a simulation driven optimization process. A calibrated model can be used for optimization and decision making, only when a reasonable and quality forecast on the influence of different stimulation procedures on the final fracture network is given.

The calibration phase ideally requires best available quality diagnostic data. It includes surface pressure,

bottom hole pressure (BHP), and pumping rate histories from diagnostic fracture injection testing (DFIT), instantaneous shut-in pressure (ISIP) and the total slurry volume (fluid plus proppant) for each stage of the actual fracturing job. The representative microseismic event catalog is also used in the calibration phase. Not only by identifying and calibrating the most important uncertain reservoir parameters, the model calibration process also

provides insights for additional data gathering to focus on parameters that significantly affect the simulation results.

3.1.1. Calibrating of Fracture Initiation and Termination Conditions

After model initialization with *in situ* stress field, *in situ* strength conditions and initial pressure conditions, the pressures at which hydraulic fracture initiation and termination are verified. ISIP from DFIT and fracture jobs are used to define fracture initiation, fracture extension, and closure pressure. Typical adjustments during calibration to ISIP conditions including formation pressure, *in situ* stresses and strength conditions of the natural fractures within and nearby the perforated layers are made.

3.1.2. Calibrations with Bottom Hole Pressure and Fracture Volume

By applying the actual pumping rate, we calculate the BHP (bottom hole pressure) response and compare with the BHP data from the actual fracturing job. The major parameters calibrated in this step are strengths of intact rocks, activated mean fracture spacing and strengths of the natural fractures in the different layers. In addition, the generated total fracture volume is calculated based on mechanical openings of the fracture and compared with the pumped total fluid volume. The total fracture volume should be close to the pumped total fluid volume plus the fluid leak-off.

3.1.3. Calibration to Microseismic Data

Finally, the model is suitable enough to be calibrated with micro-seismic data. At the final calibration step, all uncertain parameters including the pre-calibrated ones are taken into account by defining window of uncertainties. The goal of the final calibration step is to attain a best possible fit to all available important measurement data, ISIP, Bottom Hole Pressure history and fracture extension in time and space (microseismic).

Microseismic data provides the time, position, and magnitude of each individual microseismic event, which is believed to represent the shear failure of reservoir rocks during hydraulic fracturing. The “dot-plot” of microseismic events is used as a representation of the spatial extension of hydraulic fractures. For model calibration with microseismic data, the “dot-plot” cloud is compared to the model fracture growth. If the calculated fracture opening in a failed element exceeds a certain threshold, the time step and the location of

the element center point is stored. The distance between the center of the cracked element and the stage center is calculated and compared to the microseismic cloud.

Consideration of over hundred uncertain parameters of the layered reservoir is quite complex. To handle plenty of such parameters, optiSLang is used to perform a sensitivity analysis to identify the most important parameters. Subsequently, only the most important parameters are updated in the calibration while the others stay with their mean values in the window of uncertainty. After a reasonable sample set of possible parameter combination is computed, optiSLang searches for subspaces of important parameters and generates metamodels of optimal prognosis (MOP) between input and simulation result variation. The best possible metamodels are selected based on their forecast quality using coefficients of prognosis (COP) measures. For details of the sensitivity analysis and calibration algorithms refer to [10]. In addition, the metamodels provide insights about the ranking of the uncertain parameters based on their impacts to important results as well as the objective function defined in the final calibration step.

3.1.4. Calibration to Production Data

After fracture propagation is calibrated, the final calibration step to estimate production from the generated fracture network is performed. So far two approaches are used. The first approach calibrates the drainage distance from fractures into the payrock and calculates the drainable volume and related accessible hydrocarbons connected to the well, based on the proppant accepting simulated rock volume. Finally, a recovery factor translates AHCIP into EUR. The second approach exports the fracture network to reservoir simulators which calculate time-dependent production.

Once the model is calibrated to all available data, it is then used in forecast mode to optimize well and completion designs.

4. FIELD APPLICATION

In [7] optimization of hydraulic fracturing operational conditions based on modelling of 3 stages along one well is discussed. 12 different rock layers (Figure 8) are modelled to represent the reservoir characteristics important to the fracture generation including 2 fracture barriers.

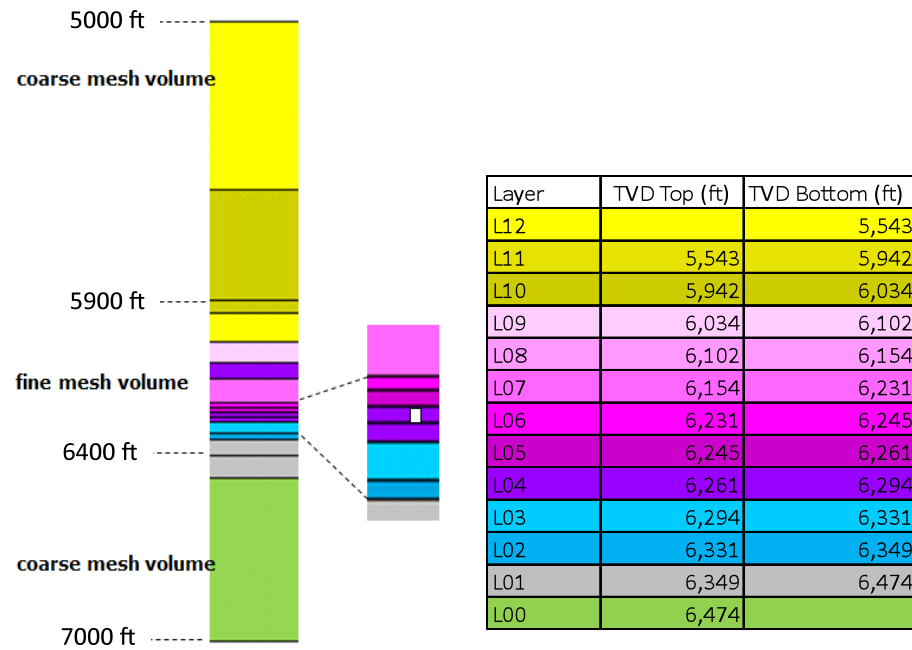


Figure 8: Stratigraphic column of all modeled layers.

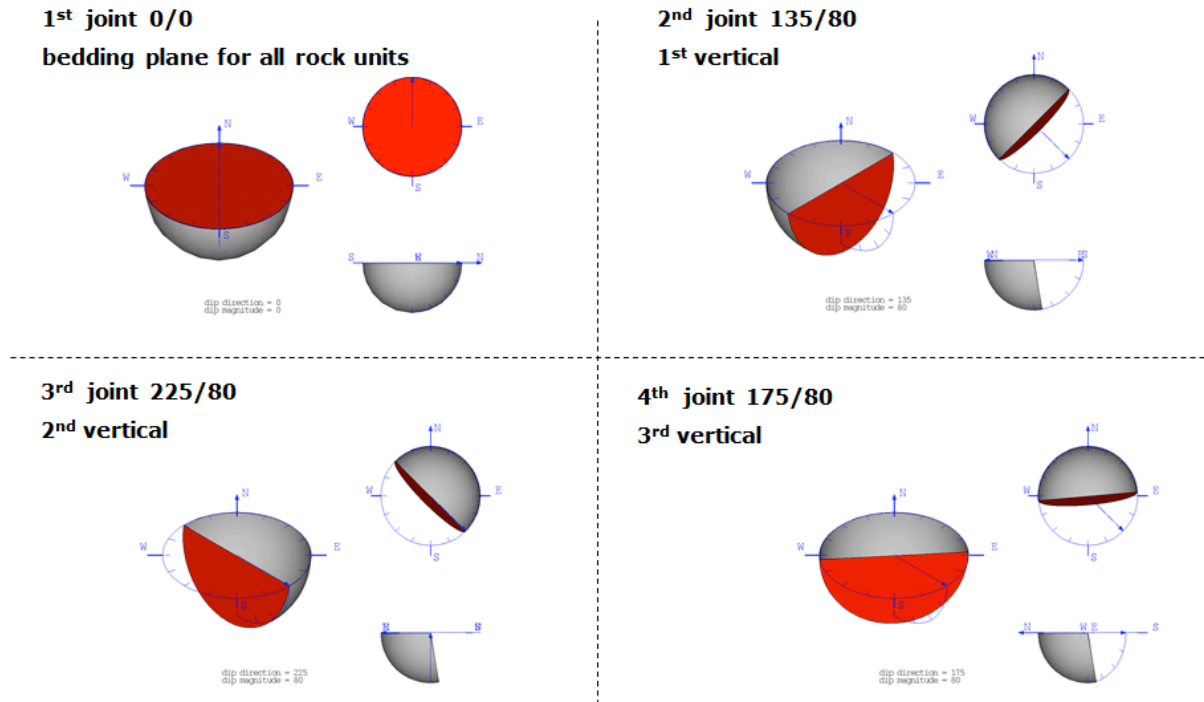
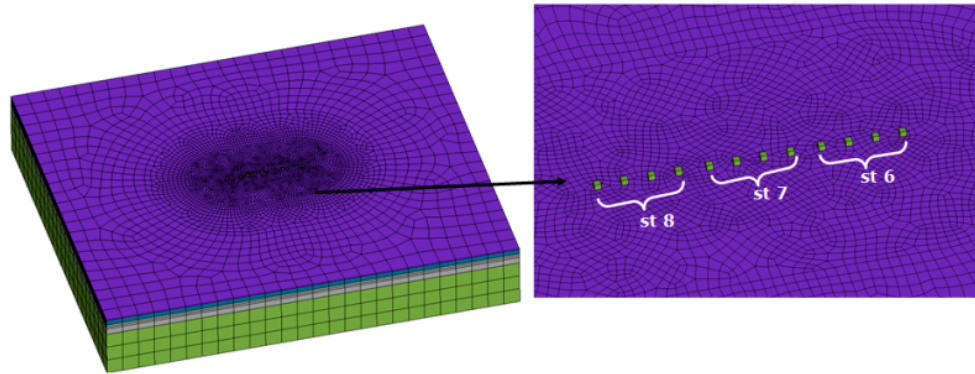


Figure 9: Orientations of the planes of weaknesses considered in the model.

The strength anisotropies of the reservoir were characterized by 4 oriented sets of planes of weakness, one bedding plane and 3 almost vertical joint sets (Figure 9).

The resultant FEM mesh for the one well model with 3 stages model is shown in Figure 10, having roughly 200.000 mechanical elements and 1.6 million fluid cells. Simulating the 3 stages on regular hardware (up to date PC using 4 cores) last about two days.

(a)



(b)

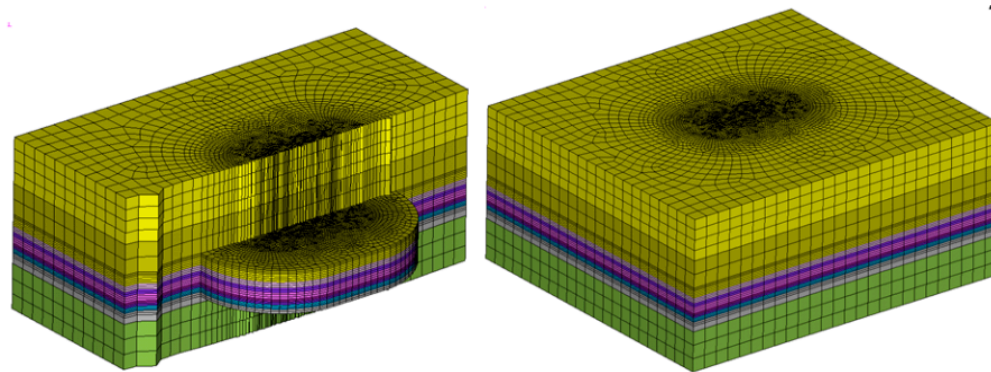


Figure 10: FEM Meshes. (a). FE-Model with stage 6,7,8 and perforations in layer L04. (b). Mesh for hydraulic analysis.

The process of calibration of the one well model was performed by best matching ISIP conditions, the BHP function's (Figure 11) and micro-seismic clouds (Figure 12), including the locations of fracture barriers. The strength of the joint system, which is very important to match ISIP and fracture extension is calibrated to have a friction angle of 20.5°, cohesion of 25psi and tensile strength of 5 psi. Only by modelling

the fracture barriers without *in situ* joint sets the containment of fracture height growth could be calibrated.

After the forecast quality of the model was proven, the calibrated model is used for optimization of the operational parameter. VSRV is used as optimization criteria and potential of doubling the VSRV is

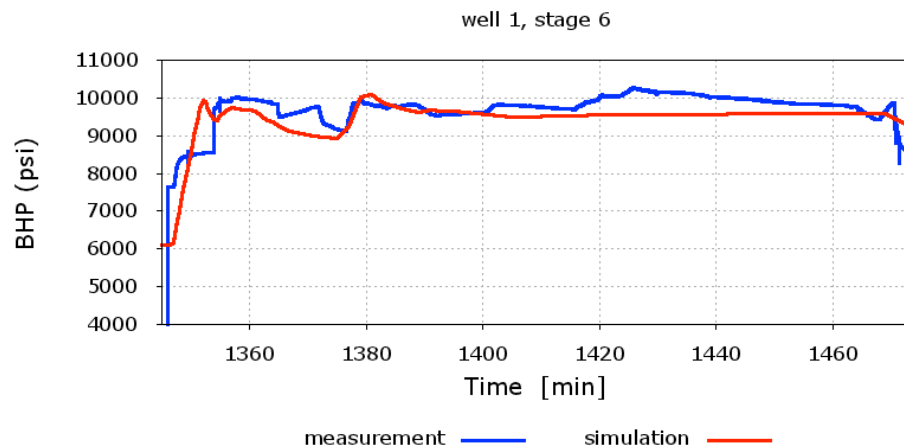


Figure 11: Stage 6 comparison between model calculated BHP (red) versus actual BHP (blue) using pumping rate as the input.

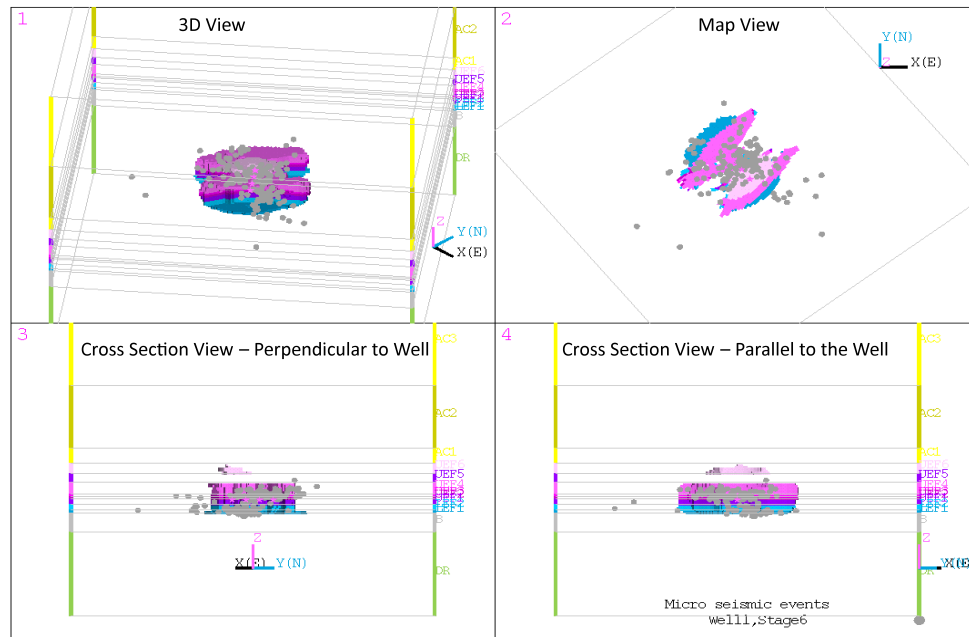


Figure 12: Plot of connected proppant-accepting elements and microseismic events at the end of Stage 6.

forecasted in the given window of variation of the operational parameter. Of course, the potentials to improve are dependent on the freedom of variation of the operational parameter as well as on the status of the start designs, representing the current best practice within that window in the reservoir.

In addition, to use the calibrated reservoir model for optimization of operational conditions, the model was used to forecast production of neighboring wells. Figure 13 illustrates that the inhomogeneity of the reservoir

operation of the different wells very well. Forecasted EUR from the numerical model and DCA-based EUR estimation correlate with a linear correlation coefficient of 0.8. The picture also shows the best possible production out of the optimization exercise compared to current wells.

When the model shows potential for improvement, the next challenge is to apply changes in operational conditions in the field. By implementing a field test, where modifications in stage design only are implemented, and early production showed more than 20% uplift in production from the well completed with the optimal stage design compared to the base design used on the other 4 wells in the pad. The results convinced the asset about the forecast quality of the simulation. The 20% uplift represents the particular contribution of optimization of the operational parameter which does not affect the cost of stimulation too much. The main part connected to more fluid/proppant resulting in much larger fracture half-length became part of controversial discussions and resulted in the requirements to enhance the workflow with cost estimations as well as to verify the production potentials of much larger fracture networks with reservoir simulators.

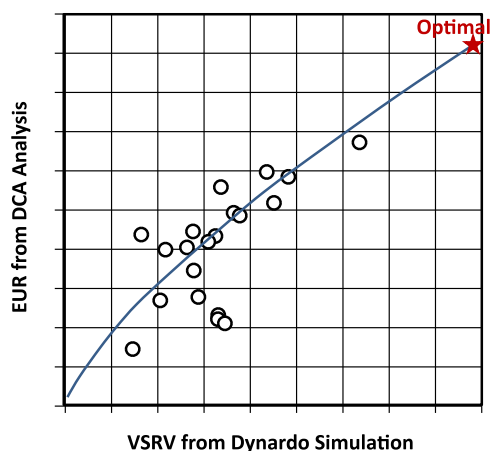


Figure 13: Plot of decline curve analysis (DCA) derived EUR versus Dynardo predicted VSRV values.

within a radius of 10.000 ft does not dominate production differences and the model is able to represent the impact on production of the different

5. SUMMARY

The geomechanics technology provides a subsurface based completion optimization toolkit that

integrates subsurface, well, completion, production, diagnosis, and unit operating cost for well and asset value delivery. Compared to common practice, i.e., field trials, such technology offers a much more economical and efficient alternative approach for developing an optimal well completion design for EUR improvement. Application of the technology clearly showed its potential in improving predictability. We are convinced that such integrated workflow is feasible to derive an optimal completion design that will deliver significant value to the unconventional resource play.

The workflow is successfully applied at Shell Unconventional Reservoirs worldwide [7, 11]. Field trials based on the results from the above approach have yielded encouraging production uplifts with quality forecasts. We believe it is technically feasible to derive an optimal completion design using a subsurface based forward modeling approach that will deliver significant value to the industry.

REFERENCES

- [1] ANSYS, Inc., ANSYS®, Release 17, Canonsburg, PA, 2016.
- [2] Dynardo GmbH, 3D Hydraulic fracturing simulator, version 3.7.4, documentation.ppt, Weimar, 2016.
- [3] Dynardo GmbH, optiSLang® - The optimizing structural language, Version 5.1, Weimar, 2016.
- [4] L. Weijers. Evaluation of oil industry stimulation practices for Engineered Geothermal Systems, Pinnacle Report DOE-PS36-04GO94001, "October 2007.
- [5] M. G. Zielonka, K. H. Searles, J. Ning and S. R. Buechler, Development and validation of fully-coupled hydraulic fracturing simulation capabilities, in 2014 Simulia Community Conference, 2014.
- [6] W. Wittke, Felsmechanik: Grundlagen für wirtschaftliches Bauen im Fels, Springer-Verlag, 1984.
<https://doi.org/10.1007/978-3-642-52235-2>
- [7] T. Bai, J. Will, *et al.* Hydraulic modeling workflow and toolkits for well completion optimization in Unconventionals. SPE 179137 Hydraulic Fracturing Conference in Woodlands in USA 2016.
- [8] J. Will, Beitrag zur Standsicherheitsberechnung im geklüfteten Fels in der Kontinuums- und Diskontinuumsmechanik unter Verwendung impliziter und expliziter Berechnungsstrategien, in Berichte des Institutes für Strukturmechanik 2/99, Dissertation, Bauhaus Universität Weimar, 1999.
- [9] R. Schlegel, J. Will and M. Jobmann, Using statistical methods for rock parameter identification to analyse the THM behaviour of Callovo-Oxfordian claystone, in Second EAGE Workshop on Geomechanics and Energy, Celle, 13-15 October 2015.
<https://doi.org/10.3997/2214-4609.201414298>
- [10] T. Most and J. Will. Efficient sensitivity analysis for virtual prototyping, in Proceedings of the 6th European Congress of Computational Methods in Applied Sciences and Engineering, Vienna, 2012.
- [11] Y. Gao, R. Yuan, J. Will, T. Bai, *et al.* An integrated Geomechanics-Reservoir modeling workflow for Hydraulic Fracturing optimisation and EUR prediction for a shale gas play in Sichuan Basin; SPE 181801, Asia Pacific Hydraulic Fracturing Conference 2016.
<https://doi.org/10.2118/181801-MS>
- [12] Venkat S, Eckardt S, Will J. Simulation of penny shaped fracture using homogenized continuum approach; Proceedings Weimarer Optimierung- und Stochastiktage 2015, Weimar, Germany (www.dynardo.de).
- [13] Ranjan A, Eckardt S, Will J. Simulation of fracture design generation, production characteristics and temperature development of a Hot Dry Rock Geothermal Reservoir; Proceedings Weimarer Optimierung- und Stochastiktage 2015, Weimar, Germany.

Received on 08-01-2017

Accepted on 06-03-2017

Published on 25-07-2017

DOI: <http://dx.doi.org/10.15377/2409-787X.2017.04.01.3>

© 2017 Will and Eckardt; Avanti Publishers.

This is an open access article licensed under the terms of the Creative Commons Attribution Non-Commercial License (<http://creativecommons.org/licenses/by-nc/3.0/>) which permits unrestricted, non-commercial use, distribution and reproduction in any medium, provided the work is properly cited.