Seeking Real Value: Quantitative Estimation of Permeability Enhancement, Production Volumes and Drainage Area from Microseismic Data

Sudhendu Kashikar, Microseismic Inc.; Hasan Shojaei, Microseismic, Inc; Peter Duncan, Microseismic, Inc

Summary

As cost efficiency becomes the priority across the industry, some operators have turned to advanced microseismic analysis techniques to improve profitability and strategy planning for unconventional field development. Through a process that quantifies a treated reservoir's current and future productivity, the short- and long-term production for entire fields can be estimated early on in a field's development cycle.

These early production predictions are available immediately after well treatment, eliminating the typical 6- to 12-month wait time for production results. The time saved enables operators to immediately evaluate the effectiveness of treatment strategies and, therefore, optimize planning for the remainder of the field without waiting for actual production data from each well.

People often worry about the uncertainty in microseismic data, but our ability to create a model that is consistent with actual production suggests that uncertainty is sufficiently constrained through the outlined process. This is proven by case history given here.

The Challenge

Resourceful field development is challenging, and the biggest hindrance is time. It takes time to wait for initial production data to indicate which was the most successful and efficient completion planning strategy. And during that wait time, new wells are being planned and completed, based on old or outdated models estimating how much production should be expected.

There is a significant gap in the industry's ability to measure and understand the contribution to production from individual wells and stages, which makes it difficult to optimize completions. Investing in traditional well intervention techniques to evaluate a well's production contribution is expensive, and results are delayed by a long wait-time. Also, each area of a reservoir is unique, making it difficult to predict how each treatment will translate to specific productivity.

A Solution – Early Production Prediction Using Microseismic Data

An alternative approach uses advanced microseismic analysis to map the propped volume of the fracture network and determine the reservoir's current permeability, which is then calibrated to predict production volumes for nearby unproduced wells.

The process for using microseismic data to predict multiple-well production volumes begins with determining the fracture intensity as described by a deterministic discrete fracture network model. The fracture intensity is then translated into reservoir permeability using an analytical method based on Oda's theory. The degree of reservoir permeability enhancement achieved by the hydraulic treatment is the most direct indicator of productivity.

Deterministic Discrete Fracture Model and Permeability
Treatment information is combined with microseismic data to create a deterministic discrete fracture network (DFN) that accurately represents the fluid and proppant distribution within the fracture network. Refer to URTeC paper 1922843 for a more detailed explanation of this deterministic DFN process.

The overall volume of productive fractures, called the Productive Stimulated Rock Volume (P-SRV) is determined by placing proppant within the DFN using a mass balance approach. One key advantage of this workflow is the ability to capture the fracture intensity (fracture number, orientation and aperture) achieved in each cell of the geocellular volume. This fracture intensity can be translated into a permeability tensor using the Oda approach, providing quantification of the unscaled permeability enhancement in each cell.

Quantifying Stage Contribution

The permeability enhancement within the geocellular volume captures the spatial distribution of the induced fracture intensity, providing immediate understanding of the potential drainage volume in the rock space surrounding the wellbore.

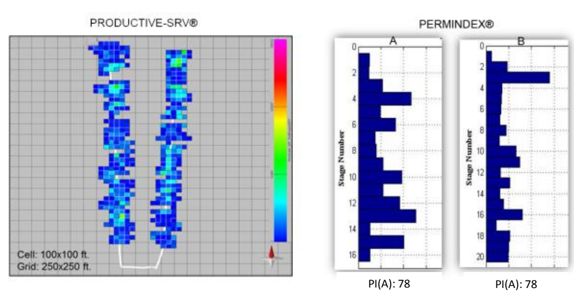

Figure 1: Stage and Well Permeability Enhancement

This provides a means of evaluating the production contribution from a given stage or well(s). Figure 1 shows the average unscaled permeability enhancement for each stage. The relative magnitude of permeability enhancement between individual stages provides a measure of production potential of individual stages. This has been verified with actual production data obtained via production logging of the horizontal well. The analysis can be extended further by computing the average permeability enhancement for entire wellbore. Comparing the relative magnitudes of average permeability enhancement allows us to rank individual well performance without waiting for production data. As shown in Figure 1, we expect well B to have slightly better performance than well A.

This analysis provides a level of analysis and understanding beyond what one can achieve only with the microseismic events. This can factor into determining which well completion procedure is more appropriate for a given area

Forecasting Production

The above approach provides rapid diagnosis of Initial Production (IP) of individual stage or well performance. However, to fully quantify the long-term production we have to take into account the spatial variations in the fracture intensity. This can be easily achieved through numerical reservoir simulation, where the size and shape of the overall drainage volume is defined by the SRV and PSRV, while the spatial variations in fracture intensity is captured by the unscaled permeability enhancement.

Numerical reservoir simulation and history-matching enable the relative productivity values for each geocell to be translated into absolute production volumes by imposing a drawdown schedule over the duration of the simulation. The result is a prediction of production volumes for each well at any increment of time during the life of the unproduced wells.

For the 2 well pad shown in Figure 2(a), the same drawdown schedule was applied to both wells to forecast the production profile for two years. The numerical simulation shows a significant difference in the IP and the decline behavior for the 2 wells. The actual production from these wells is shown in Figure 2(b). We can see good agreement between the predicted production and measured production for both wells. The differences are driven mainly by the variability in the drawdown applied to each well during production operations.

The agreement between actual production and simulated forecast confirms that it is indeed possible to forecast the production behavior of individual wells through numerical reservoir simulation by incorporating the microseismic derived permeability with other rock and fluid properties. The method provides a means of evaluating the impact of

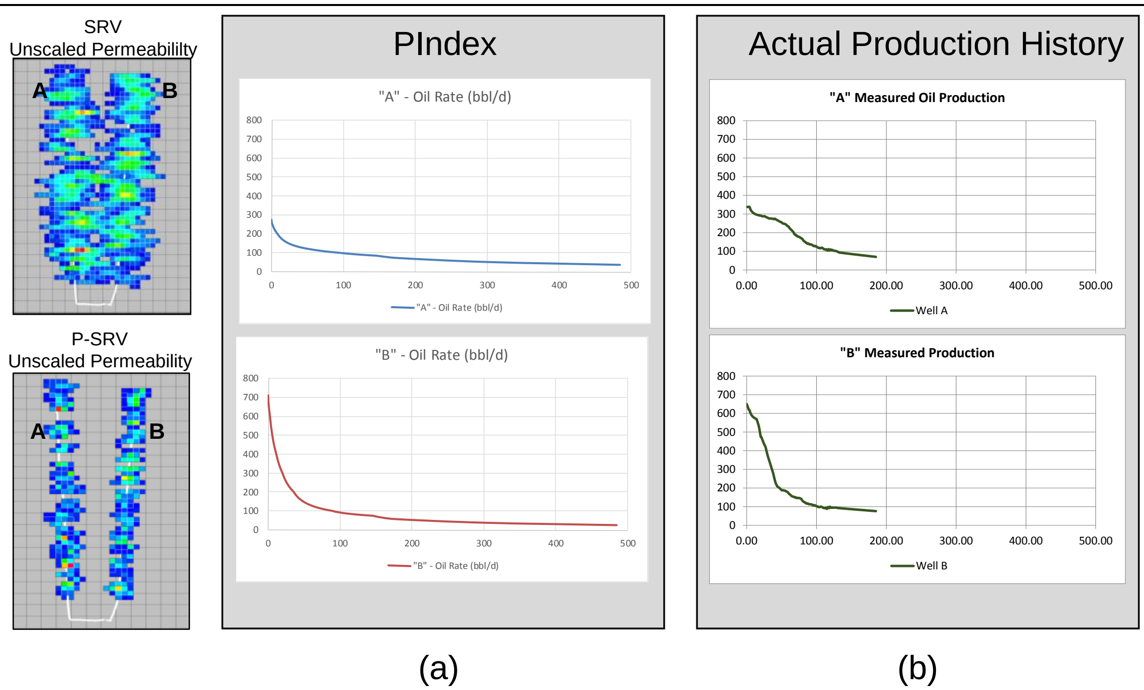

Figure 2: Forecasting Well Productivity using defined drawdown schedule

choke management on production. Several simulations can be run in a short time span to quantify the impact of drawdown on production, allowing operators to pro-actively select appropriate drawdown schedules to maximize short-term or long-term production.

Quantifying Reservoir Drainage

Reservoir drainage pattern and volume are additional outputs of the permeability evaluation process. The same process that quantifies reservoir permeability and production also shows the drainage pattern a well will create over time as the well is produced, and the volume of reserves that will be drained from the reservoir at any point in time. In a situation with multiple wells producing from the same area, mapping the future drainage patterns for each well can show how and when production will interact between wells. (Figure 3)

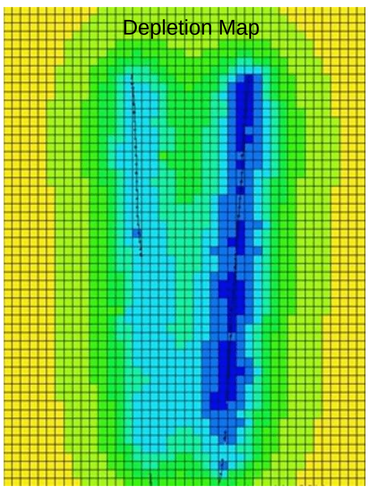

Figure 3: Pressure Depletion Map after 18 months of production

Being able to predict reservoir drainage patterns and progression gives operators the power to plan perfectly spaced adjacent wells that only intersect each other's reservoir drainage areas on a planned timeline. This ability introduces a new level of control in field planning. Wells can be planned to drain as much reservoir as possible on a short timeline when oil prices are high (i.e. accelerate recovery), or fewer wells can drain the same amount of reservoir on a longer timeline when oil prices are low, saving costs on drilling unnecessary wells when budgets are tight.

The ability to obtain production predictions for individual wells and stages enables operators to evaluate the best treatment strategy quickly, before drilling another potentially sub-optimal well. They no longer have to wait 6 months for production information to come in before they can evaluate the most efficient treatment methods.

Case Study: Diagnose Multi-Well Productivity

Background

The operator was completing a series of wells in the Woodford formation in Oklahoma. Surface geophones were used to record the hydraulic fracturing activity of five wells.

The microseismic data was analyzed to model the DFN, P-SRV, and reservoir permeability enhancement achieved by the hydraulic treatments on all five wells. The DFN model was then integrated with PVT lab measurements, core data, petro-physical well logs, and formation top surveys to build a detailed reservoir model. Permeability enhancement in x-, y-, and z-direction was estimated based on the total number of fractures, their orientation and geometry in each cell of the grid that was superposed on reservoir volume as shown in Figure 4.

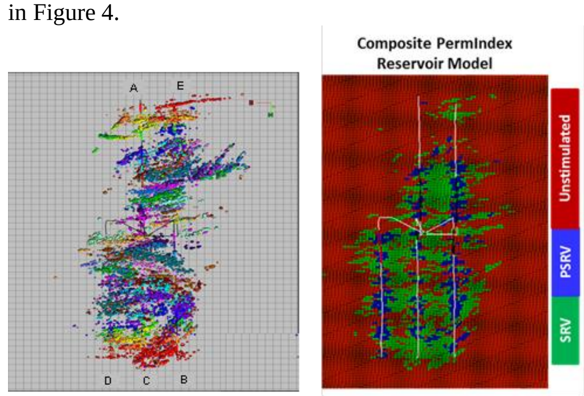

Figure 4: Left-Microseismic Data, Right-Composite Reservoir Model

Simultaneous history matching for all 5 wells of gas, and water rates was performed to calibrate the reservoir model using 16 months of production data. During the history matching process, the measured wellhead pressure was used as the input to simulate gas and water rates from all 5 wells. A scalar was applied to the geocellular permeability within the SRV and PSRV, while maintaining other properties constant. Excellent history match was obtained for all wells as shown in Figure 5(a).

The reservoir drainage pattern obtained from history-matched model, Figure 5(b), was then used to determine the preferred completion design, as well as the optimum wellbore spacing based on three different scenarios of oil price (low, medium, high) during the next 10 years.

Seeking Real Value: Quantitative Estimation of Permeability Enhancement

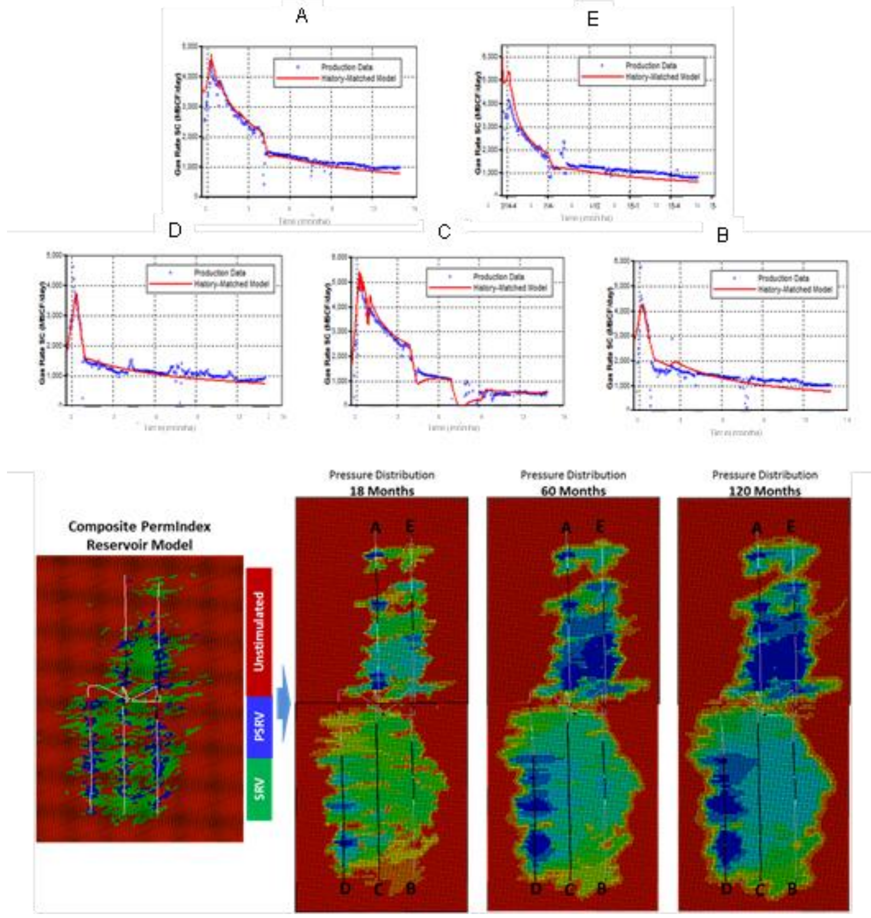

Figure 1: This caption is placed inside the frame

The reservoir model obtained in this work captures the variations in fracture geometry and intensity along the wellbore, which is contrary to traditional models that assume simple bi-wing fractures with uniform fracture spacing, half-length and conductivity. The quantified permeability enhancement for each cell, and the subsequent reservoir drainage pattern obtained from reservoir simulation, provides a success measure for treatment design of each stage, as well as the spacing among the wells. The resulting reservoir model can also be used to estimate EUR for each well.

Conclusions

There is a significant gap in the industry's ability to measure the reservoir's reaction to hydraulic fracturing and, therefore, it is difficult to predict future production from the reservoir. Microseismic-derived permeability provides a solution for understanding the reservoir after treatment, with the added benefit that this is available immediately after completion of hydraulic fracturing, without the need for well intervention. This bridges the gap between microseismic monitoring and reservoir simulation by allowing direct import of microseismic-obtained data to calibrate reservoir models.

Case studies have shown that microseismic data can be reliably used to quantify the permeability enhancement in the reservoir after a stimulation treatment. This enables operators to assess the success of a hydraulic fracture job and accurately estimate the productivity of a well immediately after the treatment. It gives operators the control to be able to balance completion and stimulation parameters to meet certain production goals and economic thresholds, and it also reduces the overall economic risk in field development.