Combining Mapped Microseismic Activity and Fracture Modeling to Estimate the Propped Dimensions of Hydraulic Fractures*

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Abstract

Monitoring and interpretation of the acoustic emissions that take place during hydraulic fracturing treatments have evolved considerably since their introduction as commercial services and continue to be applied worldwide. Mapped microseismic activity, monitored with respect to a hydraulic fracturing treatment, provides the geoscientists and engineers who are concerned with the stimulation and play assessment with a measurement of the hydraulic dimensions of the fracture. Detailed analysis of the microseismic data reveals that hydraulically induced fracture systems in both vertical and horizontal wells are influenced by a variety of factors related to the completion design as well as geology, petrophysics, and heterogeneities of the various reservoir properties. Microseismic monitoring is therefore extremely valuable in providing insights that are useful to a number of technical disciplines involved in the exploration and development of oil and gas reservoirs.

Introduction

However, several important questions remain that are not easily answered through microseismic interpretation alone. These questions are related to fracture treatment size, the number of treatment stages necessary for efficient stimulation of horizontal wells, the appropriate distance between parallel horizontal wells, and the evaluation of well performance. These questions arise because the mapped microseismic activity provides minimal distinction at best between the hydraulic or fluid-filled portion of the induced fracture, and the propped dimensions of the fracture. The inability to determine where conductivity exists within the fracture using only the mapped microseismic activity limits the ability to use the microseismic data in designing well completions for large-scale field developments and can subsequently result in unnecessary drilling and completion expenses. Decisions over investing in microseismic monitoring have been questioned because of these limitations and a solution is needed if microseismic monitoring is to continue to play an integral role in the design and evaluation of hydraulic fracturing treatments.

Discussion

It is not possible to identify where proppant is placed in a hydraulically induced fracture system by correlating the microseismic event hypocentral locations and times of occurrence with the proppant steps of the pumping schedule. As shown in Figure 1, such relationships can be unreliable. The mapped microseismic event rates from four different stimulation treatments in one horizontal well are shown with the recorded treatment pressures, injection rates, and proppant schedules. On these curves, the microseismic activity does not consistently correlate with pumping of the proppant slurry from treatment to treatment, although the stimulation schedules are relatively similar and the formation is expected to behave likewise. This observation calls into question any claim that there is a simple relationship between microseismic activity and proppant placement in the fracture.

A second approach to determine the propped dimensions of the fracture uses the calculated seismic moment for each microseismic event to estimate a volume, and then it totals those volumes. The total volume is then scaled to match the injected slurry volume minus any fluid lost to the formation through leakoff. The proppant is distributed within that volume using separate and distinct scaling factors. The results are used to recommend the number of treatment stages and distance between parallel horizontal wells for optimal reservoir drainage.

The second approach is based on several assumptions, the most important of which is that manipulating the microseismic event source parameters can be used to describe the volume of the fluid and proppant pumped during the stimulation treatments. This volumetric approach also ignores the effects of fluid viscosity and fluid velocity, which are important elements controlling proppant transport within the hydraulically induced fractures.

Volume creation within a hydraulically induced fracture is continuous until such time that the fluid leakoff to the formation and the injection rate are equal. Microseismic events are punctual occurrences associated with rock failures that take place during a fracturing treatment. Therefore, the mapped microseismic events do not represent all of the rock deformation that is associated with the hydraulically induced fracture system. Any attempt to use the microseismic data to determine where proppant has been placed within the fracture must take into account that the volume within the fracture consists in large part of deformation that is not directly measured by microseismic monitoring, regardless of the monitoring configuration used.

Proposed Solution

A detailed approach to determine where proppant has been placed within a fracture combines the microseismic data with geological models, rock mechanical properties, fluid properties, and proppant characteristics in a hydraulic fracture model. The earth model that is constructed for this interpretation method is based on the same information that has been used to design the monitoring survey and geophone locations, and to construct the velocity model. The modeling workflow that is used is applicable to both surface and downhole monitoring projects, or the combined results of both, with or without moment-tensor inversion of the microseismic data to characterize the mapped source mechanisms. The preferred approach incorporates the moment-tensor inversions to describe the discrete fracture network (DFN) to be used in the modeling, but the microseismic data can also be used where the moment-tensor inversion is not available or is not possible (e.g., poor focal sphere coverage, etc.)

It is necessary to conduct a thorough and detailed interpretation of the microseismic data prior to any modeling. Factors unrelated to the design of the pumping schedules and completion can influence the mapped microseismic events and associated fracture geometry. These factors must be identified and dealt with accordingly to avoid possible misinterpretations or misapplications of the microseismic data that would introduce errors into the modeling. For example, the interpretation method should include detailed results for each monitored treatment to identify if, and to what extent, induced stress and the completion sequence might have on the microseismic responses during the well completion.

Figure 2 shows the mapped microseismic events from a single stimulation treatment for which moment-tensor inversion has been performed. The disks represent one failure plane orientation while the spheres represent the opening component of the moment tensor. To simplify this rather complex image, events with similar source mechanisms are grouped and represent a single failure plane within the DFN. Many such groups might be identified when constructing the DFN. The collection of failure planes is then included as input into the earth model that also incorporates the stresses, petrophysical properties, and mechanical properties of the reservoir zones and bounding layers.

The fracture model is then run using the pumping schedule from the fracturing treatment to determine where the proppant has been placed within the fracture described by the extracted DFN. The model output shown in Figure 3 includes a color scale, indicating the proppant concentration in the modeled fracture.

The moment-tensor inversion output can also be used to define a DFN for forward-modeling future completions in the same reservoir and for testing of alternative completion and stimulation treatment designs. In this type of application, statistical analysis of the source mechanisms is used to generate a virtual DFN with properties similar to the DFN extracted from the events themselves.

Modifications to this workflow are required when the microseismic data do not include the moment-tensor inversion. In such cases, external information about the DFN properties, such as image log interpretations, is used to provide the necessary failure plane information for the modeling. In the absence of this information, several potential DFNs might have to be tested to find an assumed DFN that provides good agreement between the modeled hydraulic fracture geometry and the observed microseismic responses. While the lack of moment-tensor data increases uncertainty in the results, it is possible to develop a set of modeling parameters useful for evaluating the monitored stimulation treatments and to forward-model future completions.

Conclusion

Estimating proppant placement within a hydraulic fracture cannot be accomplished reliably using only the mapped microseismic events and modifications to the source parameters. A thorough interpretation of the microseismic events and stimulation treatment data must first be undertaken within a well described geological and petrophysical model. Modeling the hydraulic fracture treatments using the microseismic interpretation results as both inputs and constraints to determine the hydraulic and propped dimensions of the fracture then provides the output necessary for evaluating the stimulation treatment designs, completion designs, and well spacing considerations.

The benefits to this rigorous approach extend beyond describing the stimulation treatments that have been pumped. These benefits include using the modeling parameters to test alternative completion and stimulation treatment designs. The modeled fractures can also be used for production history matching and to forecast potential production improvement when design changes are being considered. Thus, the microseismic data and interpretation becomes an essential measurement for a broad range of technical disciplines and as a management tool for long-term planning and performance evaluation.

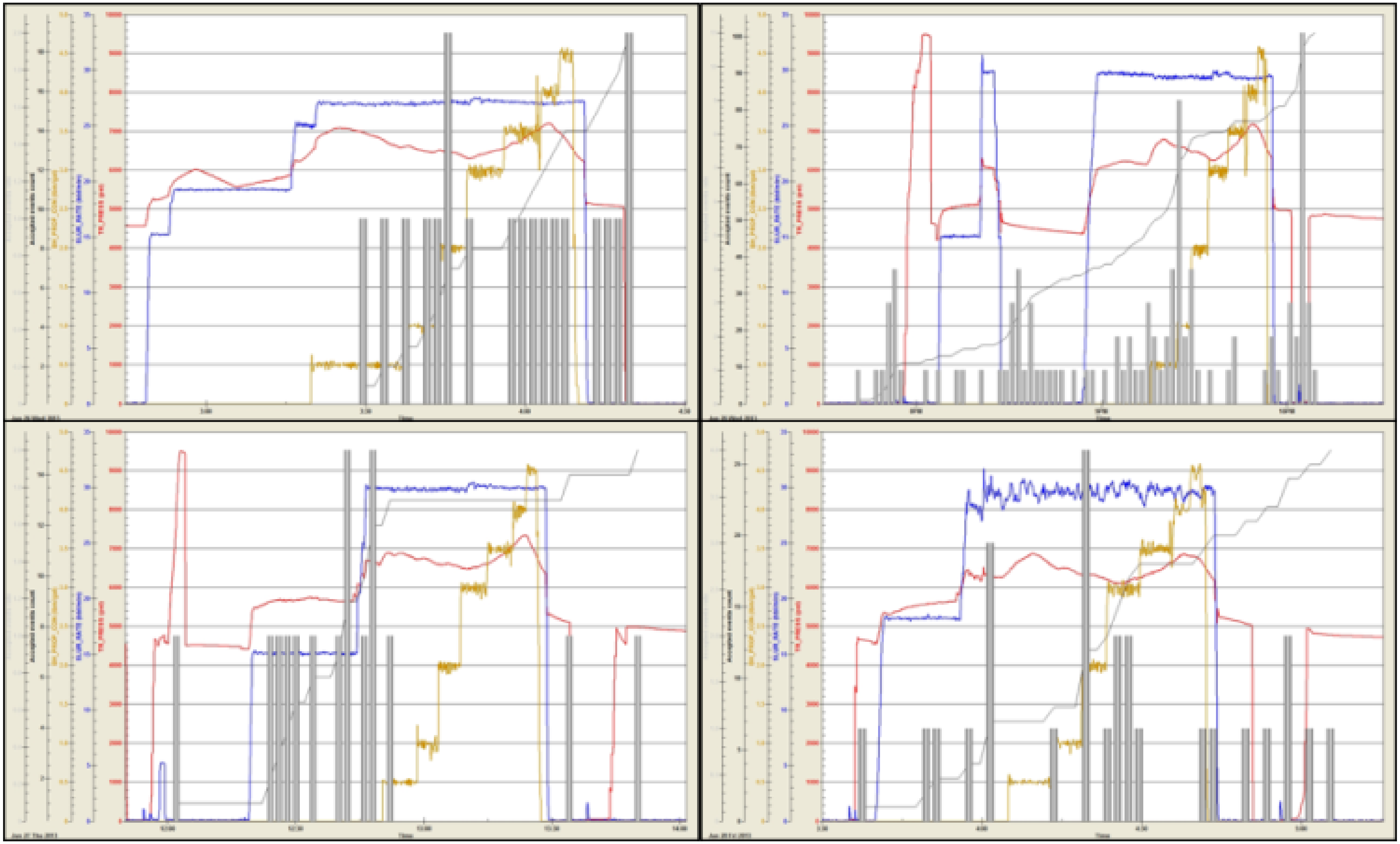

Figure 1. Microseismic event rates during four stimulation treatments with similar pumping schedules along the same lateral in an unconventional formation.

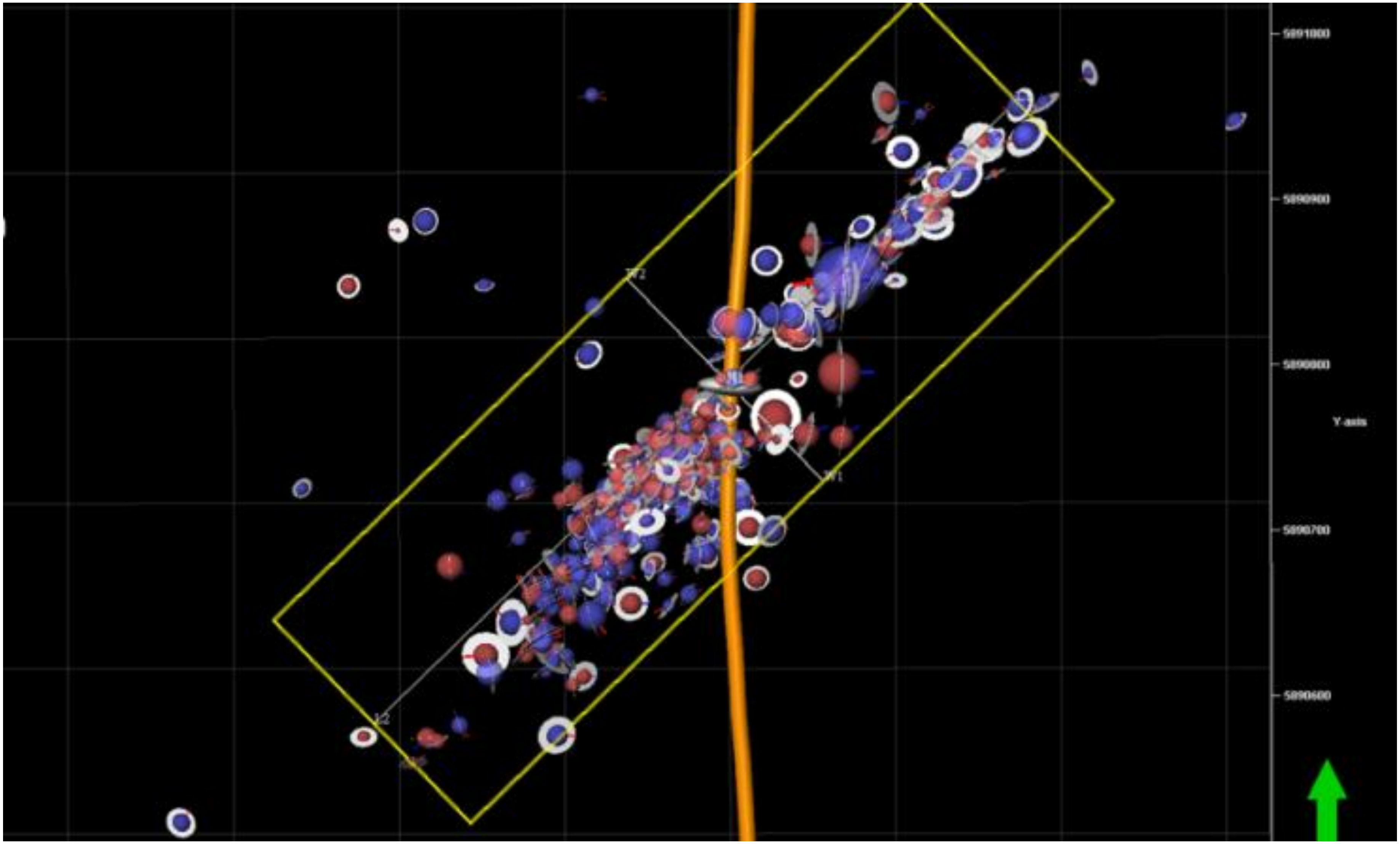

Figure 2. Glyphs showing source mechanisms of mapped microseismic events associated with a hydraulic fracturing treatment.

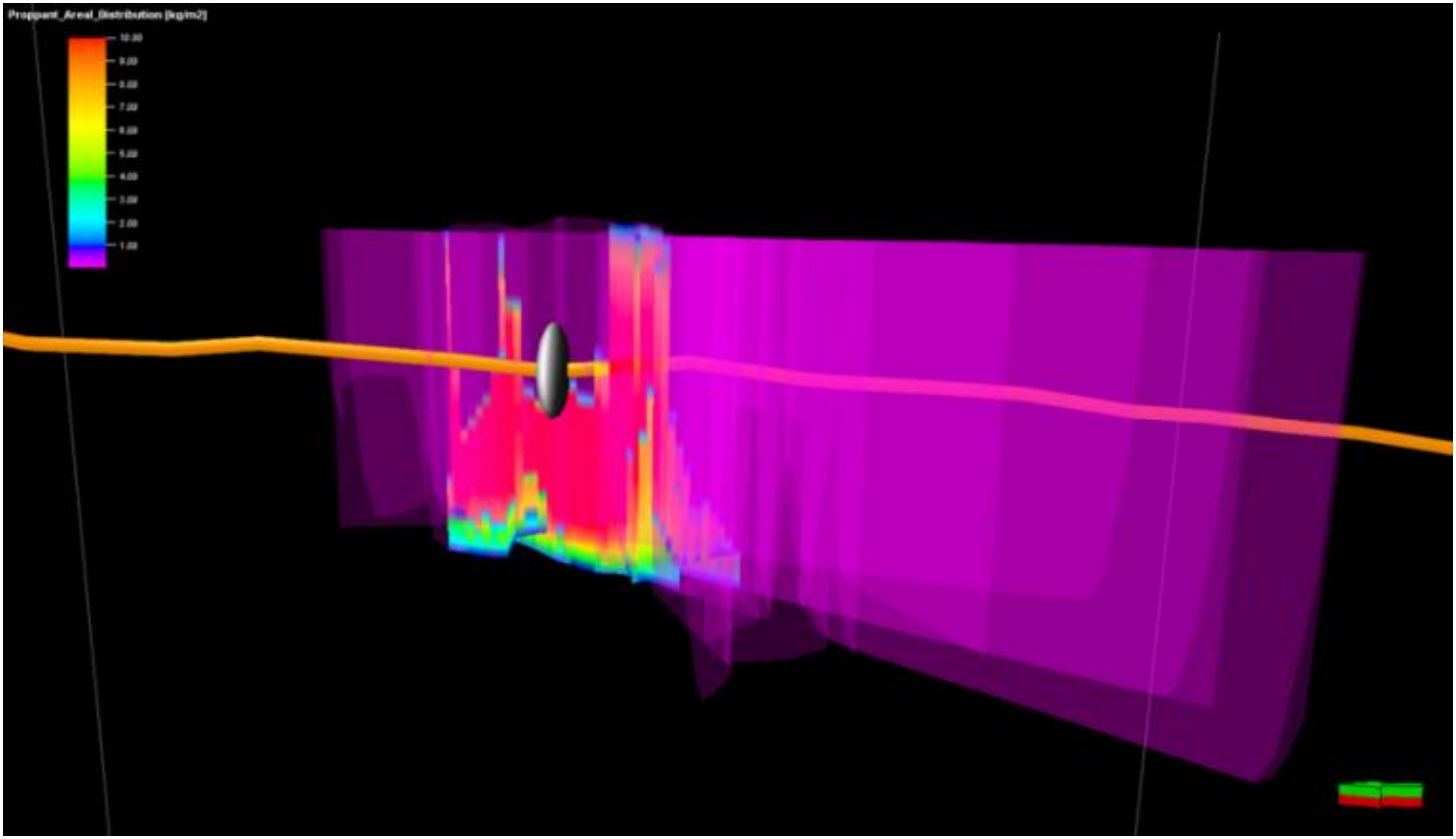

Figure 3. Modeled hydraulic fracture showing proppant concentration within the fracture.