Research Partnership to Secure Energy for America

Prediction of Fault Reactivation in Hydraulic Fracturing of Horizontal Wells in Shale Gas Reservoirs

PROJECT FACT SHEET

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2009 Unconventional Resources

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09122-06

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RPSEA Share
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Prime Contractor
West Virginia University Research Corporation

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Range Resources – Appalachian, LLC

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Reports and Publications
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Research Objectives

The overall objective was to develop a fundamental basis for characterization of geomechanical performance of shale gas reservoirs in the process of hydraulic fracturing stimulation. This project focused on predicting fault reactivation (shear slippage) and improving effectiveness of hydraulic fracturing stimulation to enhance production of horizontal gas shale wells, targeting the Marcellus shale in the Appalachian Basin. Four specific objectives were proposed: (1) assess the reactivation potentials of faults by identifying the in-situ stress conditions of faults nearby fracture treatment wells; (2) develop a propagation model for multiple fractures simultaneously created; (3) characterize the stress state changes of fault and near-fault zones, and predict fault slippage due to hydraulic fracturing; and (4) optimize fracture design avoiding reactivation of faults.

Approach

The proposed project was performed by West Virginia University, with Range Resources Appalachian LLC providing field data. Geological and geophysical data was used to develop a 3D numerical simulator for predicting fracture propagation, solving fracture geometry and stress state variations in the surrounding areas of propagated multiple fractures. The developed simulator was verified by synthetic examples and results of the field case study. The simulator was used to characterize the stress state changes of faults and near-fault zones and evaluate the potential for fault slippage due to hydraulic fracturing.

Accomplishments

A numerical stress model based on the finite element method was developed and validated with an analytical model. The developed model was used to describe the stress distribution in the reservoir intersected by a geological fault, and to compute the shear stress and normal stress fields along the fault plane. The potential of reactivation of the fault was evaluated based on the changes of stress state around the fault resulting from creation of multiple hydraulic fractures.

A 2-D coupled numerical model based on finite element method for the simulation of hydraulic fracturing propagation including fracture geometry and fluid pressure, has been developed. The change of the stress induced by hydraulic fracturing in the reservoir was accurately calculated by the program. In theory, the numerical model can simulate the simultaneous propagation of any number of hydraulic fractures. In addition, a 3-D proppant injection and reservoir production model was developed to study the transport of proppant in hydraulic fractures.

Significant Findings

This study shows that proppant settling can cause heterogeneous distribution of proppant and reduce the cumulative production by 18.6% or more depending on the reservoir matrix permeability. It also predicts an optimum proppant size to achieve maximum hydraulic fracturing efficiency in tight formations such as shale with known matrix permeability as a function of relative proppant density. The simulation results also predict that the combination of smaller proppant followed by larger proppant size can improve the stimulation performance and there exists an optimum value for larger proppant size volume injected to achieve the maximum stimulation efficiency. It also predicted that the magnitude of the difference between two proppant sizes can also significantly impact the stimulation efficiency depending on the relative proppant density.

Sensitivity analysis of proppant size while other parameters kept constant shows that in low permeability reservoirs, smaller proppant size with lower relative density is generally more suited and there is an optimum proppant size that can reduce the settling velocity and lead to a larger flow area; in a high permeability reservoir, however, larger proppant can provide higher permeability flow channels resulting in better reservoir performance.

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