CRISMAN INSTITUTE FOR PETROLEUM RESEARCH

Newsletter October 2009

This issue of the Crisman newsletter contains brief descriptions of five on-going Crisman research projects.

For more information on these and other Crisman projects, please visit our website at: http://www.pe.tamu.edu/crisman/index.html. A compiled list of the projects, including catagories and links to each project's web page, is available at: http://www.pe.tamu.edu/crisman/projects.html. For detailed information, contact one of the key investigators listed on the project.

Issue 9, October 2009

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Decision Matrix for Liquid Loading in Gas Wells for Cost/Benefit Analyses of Lifting Options (Part 2)

Objectives

Liquid loading is one of the main drawbacks of gas well production. Although there are literature reviews available regarding solutions to liquid loading problems in gas wells, a tool capable of helping an operator select the best option for a specific field case still does not exist.

The ultimate goal of this project is to fulfill the decision matrix tool initiated by a previous graduate student. Developing the tool itself and adding more available water unloading options and more limitations in each technique, using both technical and economic factors, will complete the full cycle for this project.

Approach

This project develops and expands the existing decision matrix tool used to evaluate and screen the possible available alternatives for dealing with liquid loading in gas wells. Limitations of liquid unloading techniques from literature reviews and practical actual data from the industries will be collected to become a database. A full cycle analysis of a production simulation will then be performed, emphasizing technical and economic impacts. First, simulation of gas production will be done using a material balance method. From this, production profiles and gas decline rates can be obtained. A decline curve analysis will also be done if the data available to confirm the results from the simulation exist. Then a cash flow analysis consisting of the cost and the benefits of each technique will be performed to obtain economic yardsticks such as NPV or IRR. Using these yardsticks should provide the most optimum (practical and economical) unloading technique to be selected.

Significance

By using this decision matrix tool as a preliminary screening tool, companies can determine which technique is the best fit for their conditions. The operators can also save time and money usually wasted when considering and trying many different liquid unloading techniques by themselves.

Future Work

The completed decision matrix is the ultimate goal of this project, therefore the types of liquid unloading techniques, the limitations of each technique, the actual set of production data from the oil and gas companies, and the results from production simulations have to be applied to the decision matrix codes as much as possible to make this program provide a good representation of each alternative.

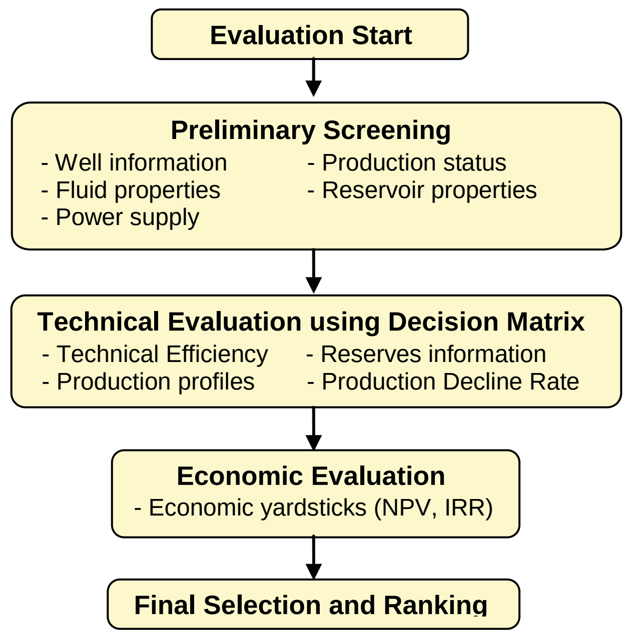

Figure 1–Flow diagram for Decision Matrix.

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Project Information

2.4.13 Decision Matrix for Liquid Loading in Gas Wells for Cost/Benefit Analyses of Lifting Options (Part 2)

Related Publications

Park, H.Y.: 2008, Decision Matrix for Liquid Loading in Gas Wells for Cost/Benefit Analyses of Lifting Options. MS thesis, Texas A&M U., College Station, Texas.

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Carbonate Heterogeneity and Acid Fracture Performance

Objectives

The objective of this work is to evaluate the expected performance of acid fracturing for two wells in the Hugoton field. Permeability data from cores and outcrops as well as mineralogical descriptions of the sampled rock will be used to characterize the carbonate heterogeneity. Specifically, the standard deviation of permeability, vertical correlation length, and horizontal correlation length will be defined. These geostatistical parameters are inputs for an acid fracture simulator developed by Mou et al. (2009) that incorporates an intermediate-scale acid etching model. This work will be combined with a model of fracture surface deformation behavior under closure stress developed by Deng et al. (2009), and the overall acid fracture conductivity will be determined for the case in the Hugoton field.

Approach

Determination of the vertical correlation length will depend on permeability measurements taken on cores from the productive zones of the Hugoton field. The horizontal correlation length will primarily depend on permeability data from outcrops, but may also be supported with well and field data, analogues, and literature on carbonates in the Chase Group. Mou's acid fracture simulator, along with Deng's model of fracture conductivity under closure stress, will be applied to this case.

Accomplishments

Core pemeability data was collected every inch over ten feet in three productive zones for two wells in the Hugoton field. From this data, the vertical correlation length can be derived through analysis of each vertical semivariogram (Fig. 1). Numerous Chase Group outcrop locations have been identified in Kansas for collection of horizontal permeability and mineralogy data.

Future Work

The models developed by Mou and Deng will be combined to produce one overall acid fracture simulator. The Hugoton case will serve as a test case by which the practicality of the simulator will be evaluated and improved as needed.

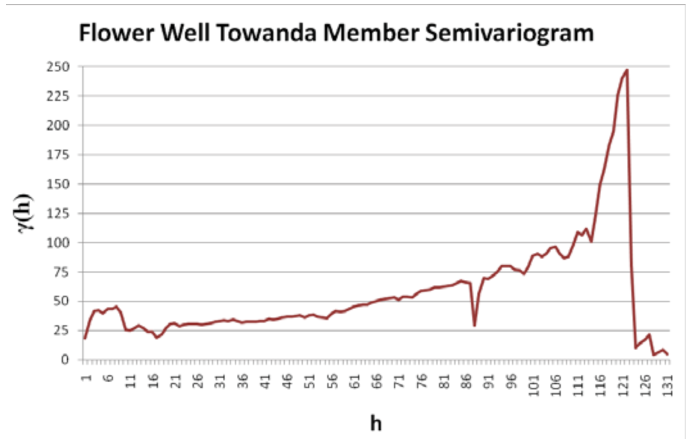

Fig. 1–Semivariogram for the Flower Well in the Towanda Member, illustrating a vertical correlation length of approximately 5 inches.

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2.5.1 Acid-Fracture Performance – Case Study of Fracture Conductivity

Related Publications

Deng, J., Hill, A.D. and Zhu, D. A Theoretical Study of Acid Fracture Conductivity Under Closure Stress. Paper SPE-124755 to be presented at the 2009 SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, USA, 4-7 October.

Mou, J., Zhu, D. and Hill, A.D. A New Acid-Fracture Conductivity Model Based on the Spatial Distributions of Formation Properties. Paper SPE-127935 to be presented at the 2010 SPE International Symposium on Formation Damage Control, Lafayette, Louisiana, USA, 10-12 February.

Mou, J., Zhu, D. and Hill, A.D. Acid-Etched Channels in Heterogeneous Carbonates—A Newly Discovered Mechanism for Creating Acid Fracture Conductivity. Paper SPE-119619 presented at the 2009 SPE Hydraulic Fracturing Technology Conference, The Woodlands, Texas, USA, 19-21 January.

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Fracture Treatments in Tight Gas Sand Reservoirs

Objectives

Gas production from low permeability sands is possible only after a successful fracture treatment. Various fracture treatment fluids, like slick water, cross-linked gel fluids, and hybrid fracture treatments have all been tried in tight gas reservoirs to optimize the completion. A hybrid treatment is where a large slick water pad is pumped to create the fracture and then the pad is followed with a smaller cross-linked volume carrying large concentrations of propping agents We have reviewed field data to see if we can find evidence from production data that allow us to determine which type of fracture fluid system is best for tight gas sand reservoirs like the Cotton Valley in Texas and Louisiana.

Approach

We have reviewed completion and production data from over 600 wells from two fields (Oak Hill & Carthage field) to see if we can correlate production to both the type of fluid pumped and the amount of propping agent used during the treatment. We generated graphs of cumulative distribution of gas production from publically available production data. We grouped the wells on the basis of the fluid used and the amount of propping agent pumped during the treatment. After the analysis of 600 wells, it was clear that as the amount of propping agent pumped into the fracture increased, the gas production also increased, which is to be expected. We also found that hybrid and gel fracture treatments tend to produce more gas over the long term than wells stimulated with water fracture treatments.

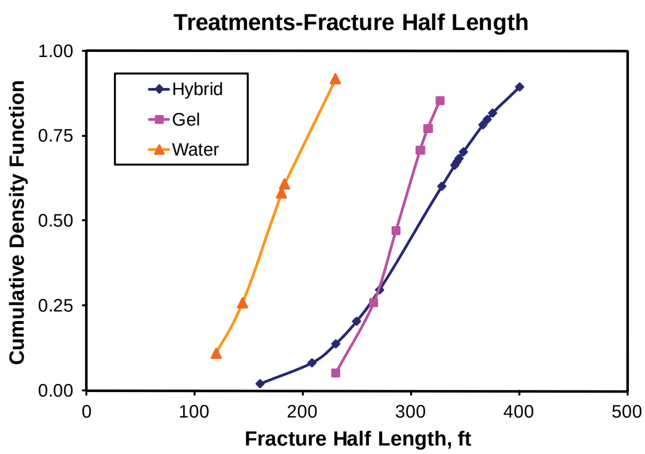

Fig. 1–CDF plot of fracture half-lengths of Elm Grove Field

To evaluate the treatment size, we analyzed in detail 25 wells in the Elm southern portion of the Grove field in the Cotton Valley formation. We performed a history match of the gas production from each well using an analytical simulator to calculate the fracture half-lengths and drainage areas. Fig. 1 shows the fracture half-lengths. We found out that the hybrid wells have longer fracture lengths and larger drainage areas.

Significance

There is a lot of misconception in the industry on the best fluid to use when stimulating low permeability gas reservoirs like the Cotton Valley formation. It appears from production data that a hybrid treatment where a large slick water pad is followed by a low concentration cross-linked fluid carrying propping agent is the best method for maximizing gas production from vertical wells. In our research, we have also looked at the effect of layers on the analyses of tight gas reservoir production data and have evaluated the minimum production required at various gas prices to be able to drill and complete economic tight gas wells.

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2.5.9 Hydraulic Fracturing in Tight Gas Sands

Related Publications

Malpani, R.V., 2006. Selection of Fracturing Fluids for Stimulating Tight Gas Reservoirs. MS thesis. Texas A&M U., College Station, Texas.

Ozobeme, C.C., 2006. Evaluation of Water Production in Tight Gas Sands in the Cotton Valley Formation in the Caspiana, Elm Grove and Frierson Fields. MS thesis. Texas A&M U., College Station, Texas.

Vera, S.A.J., 2006. Using Multi-layer Models to Forecast Gas Flow Rates in Tight Gas Reservoirs. MS thesis. Texas A&M U., College Station, Texas.

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Ramakrishna Yalavarthi

Finite Element Modeling of Near Welbore Geo-Mechanics

Objectives

Reservoir geomechanics simulation plays an important role in oil production forecasting and understanding of wellbore stability. In oil production, or water injection in recovery process, fluid and solid have interacted with each other as the pore pressure affects the stress and displacement in the solid matrix. Especially near the wellbore, there are significant changes of stress due to the increase of pressure in injection wells. Therefore, we need to take into account the geomechanical simulations for the prediction of rock failure and permeability change around a wellbore.

Approach

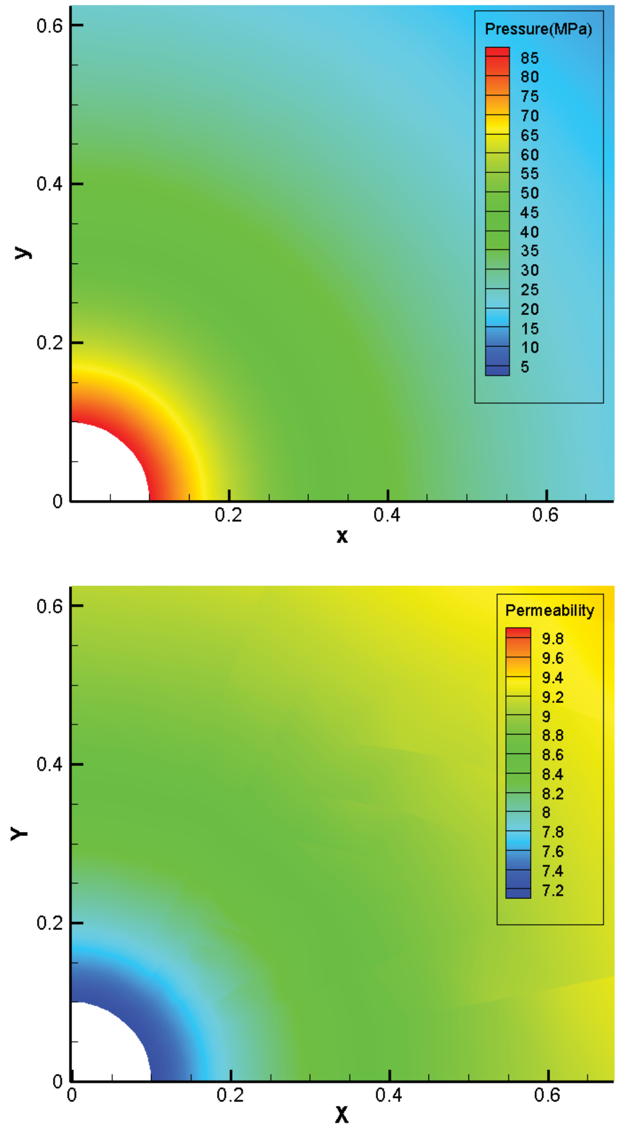
Theory of poroelasticty explained the relation of fluid and solid in porous rock with the coupling of the fluid and stress, which is based on linear stress-strain constitutive relations with Darcy's equation. In this project, finite element method is used to solve the coupled differential equation for stress and pore pressure.

Significance

Stress and pore pressure distributions are obtained for the prediction of permeability change near the wellbore in this simulation. The significance of the findings of this project is to show the large changes of stress and permeability under constant water injection rate conditions.

Future Work

The goal of this project is to develop the finite element code for the prediction of rock failure and permeability variations with respect to the stresses change which are also interacted with fluid movements. To improve our simulation, we will embed a damage mechanics theory with heterogeneous rock properties. Also, fractured reservoir simulation and multiphase flow simulations could be investigated.



Finite element results for pore pressure and permeability distributions near the wellbore. (Sandstone, Constant injection rate at the wellbore)

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3.1.21 Reservoir Geomechanics Modeling

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Sang Hoon Lee

Improved Permeability Predictions Using Multivariate Analysis Methods

Introduction

Predicting rock permeability from well logs in uncored wells is an important task in reservoir characterization. Due to the high costs of coring and laboratory analysis, typically cores are acquired in only a few wells. Since most wells are logged, the common practice is to estimate permeability from logs using correlation equations developed from limited core data. Most commonly, permeability is estimated from various well logs using statistical regression. For sandstone reservoirs the logarithm of permeability can be correlated with porosity, but in carbonate reservoirs the porosity-permeability relationship tends to be much more complex and erratic.

Objectives

In order to improve the permeability estimation in complex carbonate reservoirs, several statistical regression techniques have already been tested in previous work to correlate permeability with different well logs (Lee, Arun and Datta-Gupta 2002; Mathisen, Lee and Datta-Gupta 2003). It has been shown that statistical regression for data correlation is quite promising in predicting permeability in complex reservoirs, but using all the possible well logs to predict permeability may not be appropriate because the possibility of spurious correlation increases as more well logs are used. Therefore, the objective of this study is to further improve permeability prediction by selecting appropriate well logs for data correlation via variable selection procedures.

Approach

In statistics, variable selection is used to remove unnecessary independent variables and give a more robust prediction. We apply variable selection methods to the permeability prediction procedure to improve permeability estimation. Specifically, we propose a new method combining the stepwise regression with Alternating Conditional Expectation (ACE) technique and compare the proposed method with two other methods: the tree regression and the Multivariate Adaptive Regression Splines (MARS) method.

Significance

Three methods were tested and compared using data from a complex carbonate reservoir in west Texas: the Salt Creek Field Unit (SCFU). The results of SCFU show that the stepwise regression with ACE method outperforms the other two methods in permeability prediction. Figure 1 shows the result of the stepwise regression with the ACE method vs. true permeability for a blind test data set.

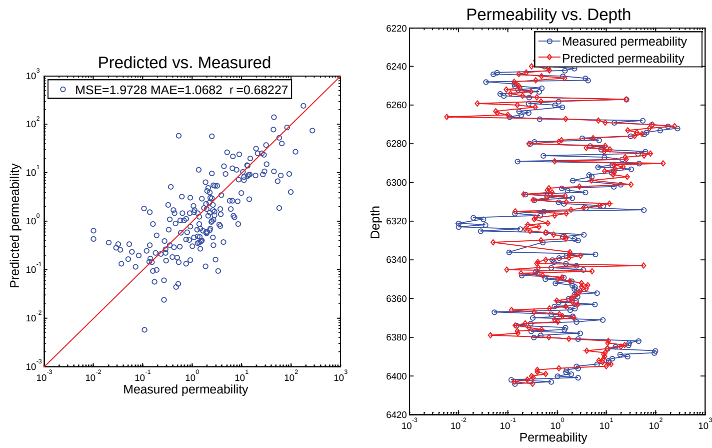

Fig. 1–Permeability Predictions from Well logs Using Stepwise Regression with ACE (Alternating Conditional Expectations) for the Salt Creek Field Unit, West Texas.

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3.2.13 Improved Permeability Predictions using Multivariate Analysis Methods

Related Publications

Lee, S. H., Arun, K. and Datta-Gupta, A. Electrofacies Characterization and Permeability Predictions in Complex Reservoirs. *SPE Reservoir Evaluation & Engineering*. (June 2002)

Mathisen, T., Lee, S. H. and Datta-Gupta, A. 2003. Improved Permeability Estimates in Carbonate Reservoirs Using Electrofacies Characterization: A Case Study of the North Robertson Unit, West Texas. *SPE Reservoir Evaluation & Engineering* **6** (3): 176-184.

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