Cooperative inversion for reservoir characterization of heavy oil fields

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Summary

Cooperative inversion for petroleum reservoir characterization produces an Earth model that fits all available geological, geophysical and reservoir production data. The mathematical formulation for the inversion requires an appropriate modeling description of both seismic wave propagation and reservoir fluid flow. The inversion requires the minimization of an objective function which is the sum of model misfits for both geophysical and production data. While the complete automation of cooperative inversion may be intractable, geophysical data can provide useful information for enhanced heavy oil production. Case histories are given to demonstrate possible cooperative inversion applications.

Introduction

The science of reservoir characterization integrates geological, geophysical and reservoir production data in order to optimize petroleum production. Reservoir characterization is becoming increasingly important and is essential for enhancing oil production. Since the world's heavy oil reserves are now estimated to be roughly equivalent to conventional oil reserves, there is an increased focus on reservoir characterization of heavy oil fields.

Cooperative inversion attempts to produce an Earth model whose model response matches all relevant data sets (Lines, Schultz, and Treitel, 1988). The term "cooperative inversion" is used here to include "joint inversion" and "sequential inversion of data sets. It has been demonstrated that the cooperative inversion of many different data types will reduce the ambiguity of inverting one particular type of data. Therefore, the basic premise of this paper is that the ambiguities of reservoir modeling can be reduced by using all available geological, geophysical, and reservoir production data, and that cooperative inversion can produce an improved model. It is also assumed that the estimation of a valid reservoir model will aid in the enhanced oil recovery (EOR). This has been advocated by Gosselin et al. (2003) in a procedure known as HUTS (History matching Using Time-lapse Seismic). The integrated approach is demonstrated here by showing case histories produced by CHORUS (Consortium for Heavy Oil Research by University Scientists). .

Theory and Methodology

In order to build a cooperative inversion package as described in the aforementioned papers, one must assemble a set of robust, accurate, (and hopefully fast) modeling codes that describe the geo-data and the reservoir production data. For the seismic data, we will generally use some version of the wave equation which for elastic, isotropic and homogeneous media is given by:

$$(\lambda + \mu)\nabla(\nabla \bullet \vec{u}) + \mu\nabla^2 \vec{u} = \rho \frac{\partial^2 \vec{u}}{\partial t^2} \qquad (1)$$

Here $\vec{u}$ is the displacement vector, λ, μ are the Lame elastic constants and ρ is the rock density. For porous fluid-filled media, one generally needs to go beyond the elastic case to viscoelastic or poroviscoelastic equations (Carcione (2007).

Reservoir simulation codes are used to model production history. These codes can be very mathematically complicated, and imbedded somewhere in these codes is some form of Darcy's law. In its simplest form for single-phase fluids in 1-D flow, Darcy's law has the form of:

$$q = \frac{kA}{\mu}\frac{dp}{dx} \qquad (2)$$

Here q is the fluid flow rate, k represents permeability, μ is the viscosity, A is the cross-sectional area and the magnitude of the pressure gradient is given by $\frac{dp}{dx}$.

Hopefully, both the geo-data and production data have good signal-to-noise levels, and we are aware of the noise (error levels) in our data. In order to produce a valid model whose response agrees with all our data (to within acceptable error levels), we use optimization methods. This is often done by some form of least-squares optimization which minimizes an objective function that combines the errors in geo-data and production data as in the following equations from Gosselin et al. (2003).

$$\mathrm{J}(m) = \alpha \mathrm{J}_{\mathrm{prod}}(m) + \beta \mathrm{J}_{\mathrm{geo}}(m) \qquad (3a)$$

$$\mathrm{J}_{\mathrm{prod}} = \frac{1}{2}(p(m) - d)^T W_p (p(m) - d) \qquad (3b)$$

$$\mathrm{J}_{\mathrm{geo}} = \frac{1}{2}(s(m) - e)^T W_s (s(m) - e) \qquad (3c)$$

In equation (3a), the model parameters are denoted by m, the production data are denoted by d, the production model response by p(m), the geo-data by e and the geo-data model response by s(m). Here J is the objective function which combines the misfit for the geo-data, s, and the production data, p. The W matrix contains weights for individual data values. The parameters of α and β will weigh the contributions of the geo-data fitting as compared to the fitting of production data. Of course, one of the challenges of cooperative inversion is to determine the weighting factors, α and β. These weighting factors should be related to variance of the errors in our measurements. In fact, if these weighting factors were the reciprocal of the estimated error or "noise" variance, then the objective functions would contain dimensionless norms. The estimation of weighting factors requires that the user have reliable estimates of the "noise" or "error" in our measurements. Hopefully, an accurate model should minimize our objective function.

Rock Physics, Q and the Quest for Viscosity

In cooperative inversion, we will generally wish to relate the parameters used in geo-modeling to those used in reservoir modeling, especially with sequential form of this inversion. In order to relate geomodeling parameters such as rock density and seismic velocity to reservoir model parameters such as permeability and viscosity, it is essential to utilize rock physics. For heavy oil reservoirs, this can become especially challenging since the "fluid" in the rock pores may in its cold state be more like a glass. Hence, the widely-used Gassmann's equation may not be appropriate for describing elastic parameters. In fact, Gassmann's equation may only be accurate for a heated heavy oil reservoir with lowered viscosity.

In applying Darcy's Law within a simulator, we need to have accurate estimates of permeability, viscosity and pressure gradients. Heavy oil sands have very high porosity (often exceeding 25%), very high permeability (often 1 Darcy), but contain highly viscous fluids (10,000 to 1,000,000 cp is typical). In fact the entire EOR problem for heavy oil could be described as one of lowering viscosity. To model heavy oil production, it is essential to have knowledge of viscosity.

We can measure viscosity from well samples by viscometers or by an understanding of the geochemistry. However, a crucial geophysics question is the following.

"Can heavy oil viscosity between wells be measured by geophysical methods?"

In recent years, some have attempted to relate seismic Q estimations to viscosity. Progress has been made. Both lab measurements, as produced by Mike Batzle's group (Behura et al., (2007) and computations as produced by Vasheghani and Lines (2009) are in agreement. Both agree with the Zener model for viscoelastic behaviour, as shown in Figure 1, from Vasheghani and Lines (2009). Q shows a decrease with increasing viscosity when progressing from oil in a conventional fluid state to a viscous fluid state, but then at very high viscosity Q increases again with increasing viscosity as oil goes from a viscous fluid to a near solid state. The good news is that Q does vary with viscosity. The bad news is that there is ambiguity –the same Q may have arise from states with two different viscosities. From the results of Behura et al. (2007), it would appear that one could use estimates of the shear modulus and Q to solve this ambiguity problem. This estimation of viscosity will require reliable Q measures. Q estimation has been done using VSPs, (Spencer, et al., 1982) and cross-borehole seismic surveys (Quan and Harris, 1997). It also appears that seismic reflections can arise from Q contrast alone, as shown by Lines, Vasheghani, and Treitel, 2008). More work is needed in this quest for fluid for viscosity estimates between wells.

Converting Model Grids – Upscaling and Downscaling

In addition to the issues of relating geo-model parameters to reservoir parameters is the conversion of geo-model grids to reservoir model grids. These models are generally created at different scales, and the model conversion is an issue. Conversion from a fine grid to a coarse grid (upscaling) will involve some resampling to create an effective medium. Conversion from a coarse grid to a fine grid (downscaling) will involve some interpolation issues.

Reservoir Data Examples – What has been done?

While the goal of automated cooperative inversion has not been achieved, there have been many useful applications of geophysics to reservoir characterization.

The application of 4-D seismology to monitoring of steam fronts in hot production of heavy oil has been done for almost 25 years. One of the first publications was presented by Pullin et al. (1987) provided an excellent case history from Gregoire Lake in Northern Alberta. In fact some might say that this type of monitoring was a major factor in the development of time-lapse 3-D seismology or 4-D seismology.

The use of 4-D seismology has also been successfully used in the monitoring of cold production of heavy oil (Lines et al., 2008). In cold production monitoring, seismic traveltime and amplitude anomalies coincide with the production footprints. Infill drilling will place new production wells outside these footprints to avoid pressure depletion due to wormhole zones.

A case history of cooperative inversion for heavy oil was provided by Zou et al. (2006) who compared a model derived from production data to seismic traveltimes for a field east of Lloydminster, Saskatchewan. There was a compelling agreement between model and data traveltimes which showed the need to adjust reservoir models in some areas.

Finally, it is becoming apparent that much can be done by to distinguish sand and shale lithologies in producing reservoirs. Figure 2 shows a seismic section from Dumitrescu and Lines (2010) which helped us to understand the part of a reservoir at Long Lake, Alberta. Part of the McMurray formation reservoir was a sand-dominated point bar and part was a shale-dominated channel fill which led to production problems with SAGD (steam assisted gravity drainage). We were able to successfully delineate the sands and shales by using the VP/Vs estimates from seismic data and dipole sonic logs and the density estimates from density logs and neural network analysis of seismic data. This delineation was made possible through the inversion of many different data types.

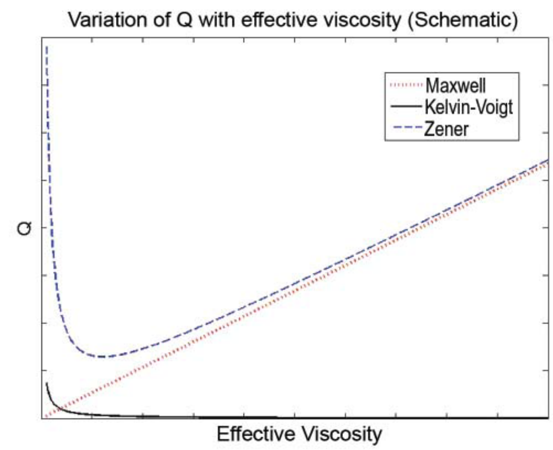

Figure 1. Variation of Q with viscosity for different models from Vasheghani and Lines (2009). The Zener model is the most general and agrees with the lab measurements of Behura et al.(2007).

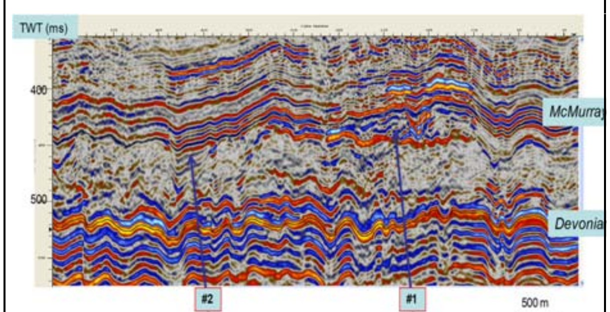

Figure 2 This figure from Dumitrescu and Lines (2010) shows two features within the McMurray reservoir: sand-dominated point-bar deposit (#1) and mud-dominated abandoned channel fill deposit (#2).

What needs to be done in the near term?

The case histories in this talk have involved intensive collaboration and cooperation between geoscientists and engineers for the reservoir characterization of heavy oil fields. The mathematical aspects and complex work flows are probably not of paramount importance to the practicing reservoir geoscientist or engineer. There are pressing deadlines for drilling schedules, logging surveys and seismic surveys so pragmatism is required. However, it is becoming increasingly apparent that one should use all available data to characterize the reservoir and the goals of cooperative inversion need to be realized.

Conclusions

Cooperative inversion has been successfully used in integrated interpretation of geophysical data. It is now time for it to be pushed to the next level – to the goal of reservoir characterization. Several case histories for heavy oil fields show that the combined analysis of geological, geophysical and production data can prove beneficial. While not yet formalized into an automated cooperative inversion algorithm, the technique has been successfully used in enhanced oil recovery.

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