Predicting heavy oil viscosity from well logs

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Summary

Viscosity is a critical parameter in selecting the best recovery method to exploit a heavy oil or oil sands reservoir. While heavy oil viscosities can be measured in the lab from well samples, it would be very useful to have a method to reliably estimate heavy oil viscosity from well logs. Donor Company has generously provided viscosity data from their Athabasca North and Athabasca South oil sands development projects, with multiple measurements per well.

Multi-attribute analysis enables a target attribute (viscosity) to be predicted using other known attributes (the well logs). In the Athabasca North area, *P-wave sonic* and *Density porosity* were used to predict viscosity with an average validation error of 147,000 cP, or 19% of the total viscosity range. In the Athabasca South area, *medium resistivity, gamma ray,* and *P-wave sonic* were used to predict viscosity with an average validation error of only 70,000 cP, or 13% of the total viscosity range.

Introduction

The fluid property with the greatest impact on oil sands recovery is viscosity (Batzle et al 2006). The more viscous the oil, more energy needs to be injected into the system to reduce the viscosity to allow it to flow. The most viscous hydrocarbon, bitumen, is a solid at reservoir conditions and softens readily when heated. Viscosity of bitumen can range from 10,000 cP [10 Pa*s] to more than 1,000,000 cP [1,000 Pa*s] (Alboudwarej et al 2006). Figure 1 shows the logarithmic scale of viscosity subdivided by the grade

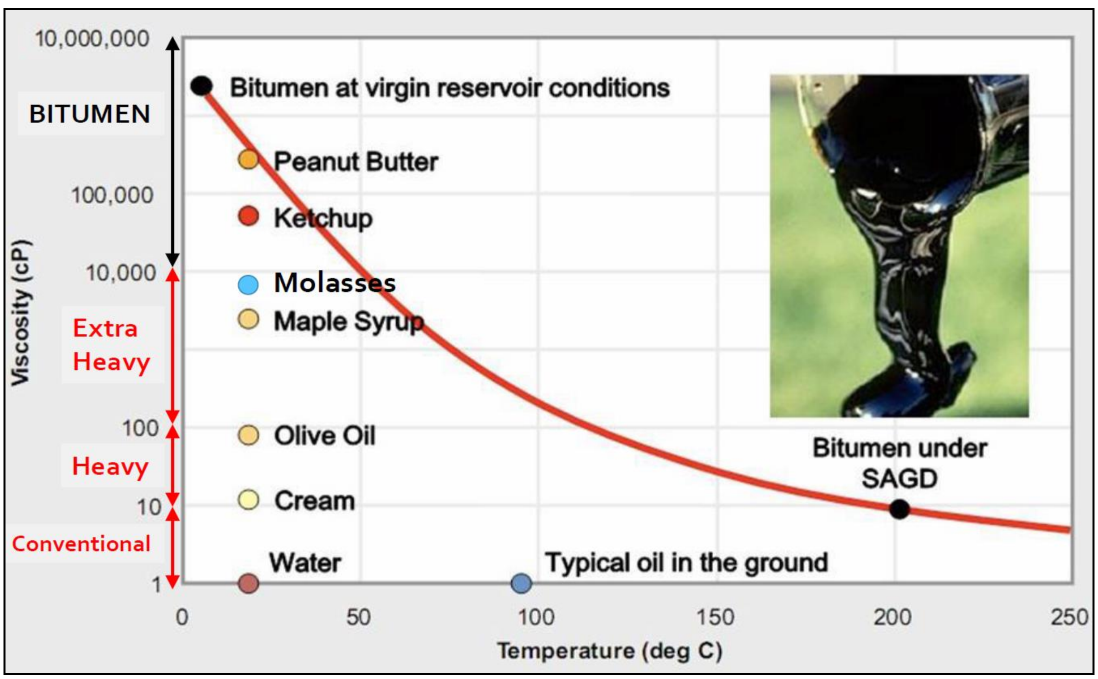

Figure 1: Oil viscosities by grade category, compared to typical kitchen items. Note that viscosity has a logarithmic scale (ConocoPhillips Oil Sands website).

category of oil, and compares it to the viscosities of typical items found in our kitchen. Figure 1 also illustrates the temperature-dependence of viscosity, showing how as an oil sands reservoir is heated, the bitumen viscosity is reduced from something resembling peanut butter to something resembling cream.

Donor Company has generously provided viscosity measurements for two of their oil sands development areas, with multiple measurements per well. The goal of this study is to establish a correlation between the measured viscosity values, and *all* of the available well log curves using multi-attribute analysis.

Theory of Multi-Attribute Analysis

Figure 2 illustrates the basic multi-attribute problem, showing the target log and, in this case, three attribute logs to be used to predict the target attribute (Hampson-Russell 2013).

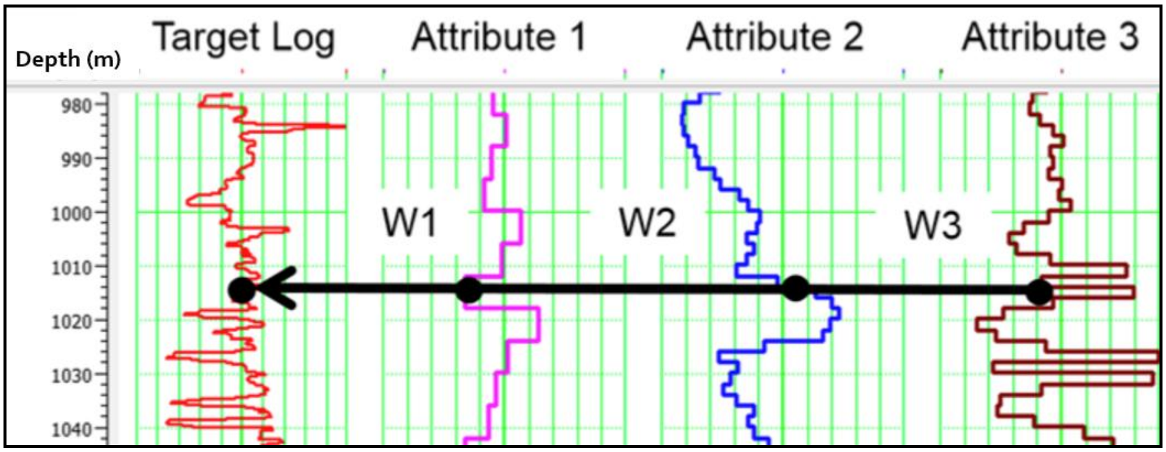

Figure 2: The basic multi-attribute regression problem showing the target log and, in this case, three attribute logs used to predict the target attribute (Hampson-Russell 2013).

To illustrate the concept, suppose that viscosity is being predicted using only bulk density, gamma-ray, and resistivity logs. The fundamental equation of linear prediction can be written as:

$$V(z) = w_0 + w_1 D(z) + w_2 G(z) + w_3 R(z) \tag{1}$$

where $V(z)$ is viscosity in centipoise (cP), $D(z)$ is bulk density in kg/m^3, $G(z)$ is gamma-ray in API units, and $R(z)$ is resistivity in ohm*m. This can be written in matrix form where each row represents a single depth sample:

$$\begin{bmatrix} V_1 \\ V_2 \\ \vdots \\ V_N \end{bmatrix} = \begin{bmatrix} 1 & D_1 & G_1 & R_1 \\ 1 & D_2 & G_2 & R_2 \\ \vdots & \vdots & \vdots & \vdots \\ 1 & D_N & G_N & R_N \end{bmatrix} \begin{bmatrix} w_0 \\ w_1 \\ w_2 \\ w_3 \end{bmatrix} \tag{2}$$

or more compactly as: $\boldsymbol{V} = A\boldsymbol{W}$. The regression coefficients, *w,* can be solved for using least-squares:

$$\boldsymbol{W} = [A^T A]^{-1} A^T \boldsymbol{V} \tag{3}$$

By using the statistical techniques of Step-Wise Regression and Cross-Validation, the best predicting attributes can be determined, as well as the optimal amount of attributes to use (Russell 2004).

Data and Results

In the ***Athabasca North*** project area, there are 24 wells with viscosity measurements which have *all* of the well log attributes available in LAS format. The viscosities (measured at 35^{o}C) range from 35,000 cP to 802,000 cP, with an average measured viscosity of 229,000 cP.

The multi-attribute analysis determined that two attributes should be used to predict viscosity: *P-wave sonic* and *density porosity*. The average validation error using two attributes is about 147,000 cP, which is 19% of the total viscosity range of the study wells (35,000 cP to 802,000 cP). The prediction equation can be written as:

$$\eta = -2174261 + 851046336\left(\frac{1}{P - wave\ sonic}\right) + 3201332(DPSS)^2 \qquad (4)$$

where η is kinematic viscosity in centipoise (cP) at a specific depth sample, *P-wave sonic* is measured in µs/m, and *DPSS* is density porosity (sandstone matrix) as a fraction.

Figure 3 shows the Athabasca North prediction results for a good predictor well, a bad predictor well, and an average well plotted beside the logs used in the prediction. The reservoir intervals are highlighted in yellow, which are the only intervals we care about, and all of the wells are scaled the same. In mud barriers between the reservoir intervals the viscosity predictions are nonsense.

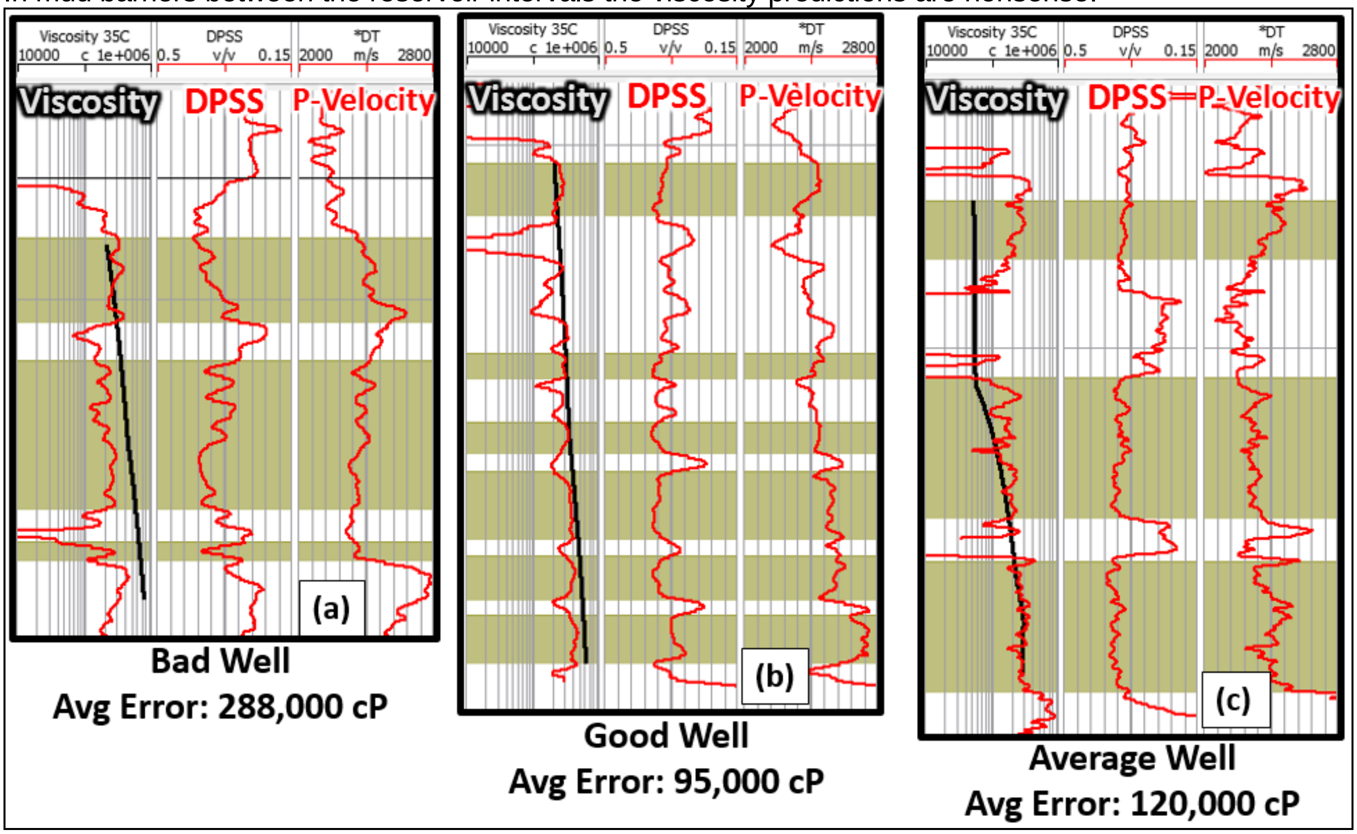

Figure 3: Athabasca North viscosity prediction (validation) results for a bad predictor well (a), a good predictor well (b), and an average well (c).The black curves in the viscosity tracks are the true (interpolated) viscosities and the red curves are the predicted viscosities using Equation 4. The logs used to predict viscosity are also plotted. The yellow areas highlight the reservoir intervals. The denoted errors are the average validation errors of each training interval within the well. Credit: Hampson-Russell Emerge™

In the ***Athabasca South*** project area, there are 40 wells with viscosity measurements which have *all* of the well log attributes available in LAS format. The viscosities (measured at 35°C) range from 9,000 cP to 550,000 cP, with an average measured viscosity of 121,000 cP.

The multi-attribute analysis determined that four attributes should be used to predict viscosity: *resistivity, gamma-ray, P-wave sonic, and deep-shallow resistivity separation.* The average validation error is about 72,000 cP, which is 13.3% of the total viscosity range of the study wells (9,000 cP to 550,000 cP). The prediction equation can be written as:

$$\eta = -96875 + 985321\left(\frac{1}{ResMedium}\right) - 31662\sqrt{GammaRay} + 176220384\left(\frac{1}{P - sonic}\right) - 10969\ln(|ResSeparation|) \tag{5}$$

where *η* is kinematic viscosity in centipoise (cP) at a specific depth sample, *ResMedium* is measured in ohm*m, *GammaRay* is measured in API units, *P-sonic* is measured in μs/m, and |*ResSeparation*| is the absolute value of the deep and shallow resistivity separation measured in ohm*m.

Figure 4 shows the Athabasca South prediction results for a good predictor well, a bad well where the base reservoir fails by about 230,000 cP, and an average well where the top reservoir somewhat fails by about 55,000 cP.

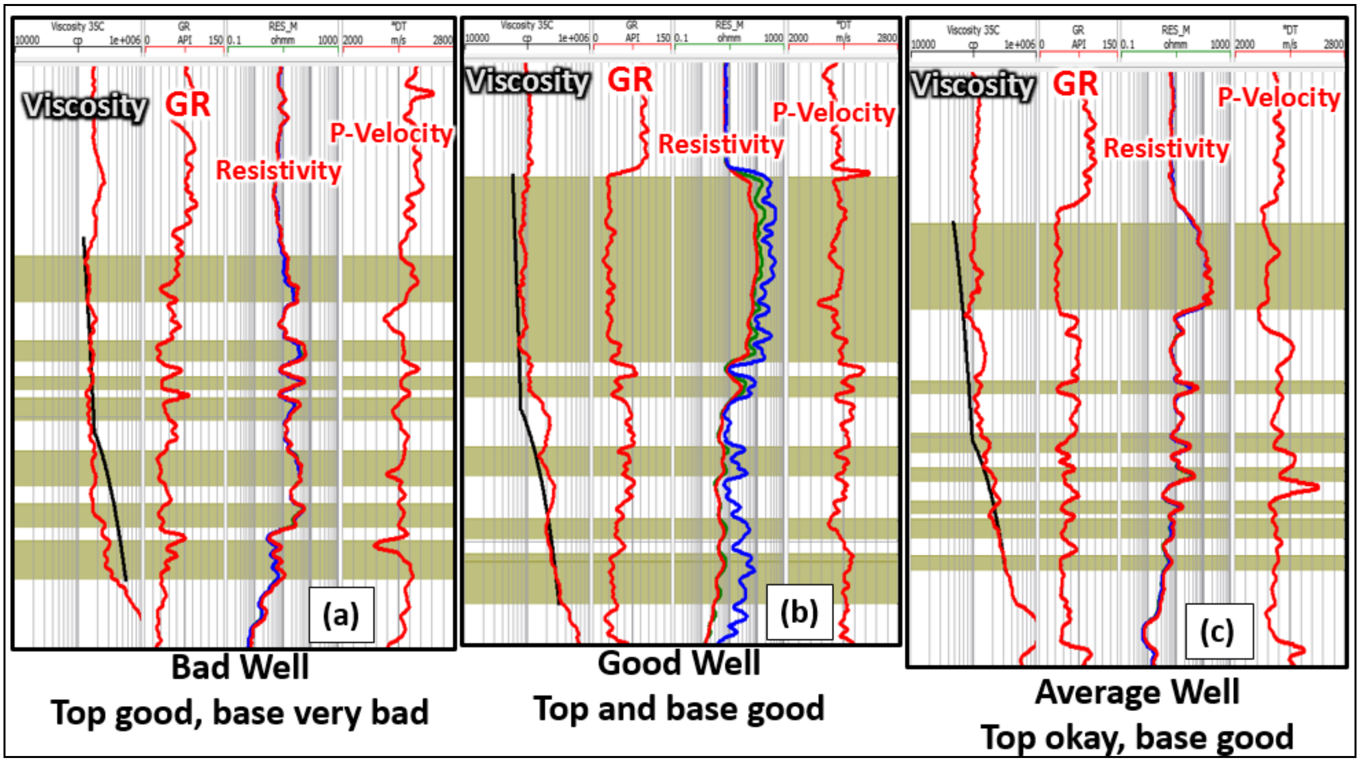

Figure 4: Athabasca South viscosity prediction (validation) results for a bad predictor well (a), a good predictor well (b), and an average well (c).The black curves in the viscosity tracks are the true (interpolated) viscosities and the red curves are the predicted viscosities using Equation 5. The logs used to predict viscosity are also plotted. The yellow zones are the reservoir intervals. Credit: Hampson-Russell Emerge™

Conclusions

Multi-attribute analysis was successfully used to determine a relationship between bitumen viscosity and well logs in both the Athabasca North and Athabasca South project areas. In Athabasca North, *P-wave sonic* and *Density porosity* were used to predict viscosity and the average validation error for all wells was 147,000cP, or 19% of the total viscosity range. In Athabasca South, *medium resistivity, gamma ray, and P-wave sonic* were used to predict viscosity and the average validation error for all wells was only 70,000 cP, or 13% of the total viscosity range.

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