Quantification of Uncertainty in Shale Gas Resource Estimates

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Summary

The Energy Resources Conservation Board (ERCB) has developed a methodology for quantifying the uncertainty in shale gas resource estimates. This methodology incorporates all available data and accounts for the uncertainty in the variables in several different ways. Geostatistical mapping, linear regression, expert interpretation, and stochastic simulation are applied in this method.

Introduction

Recent advances in fracturing and horizontal drilling technology have made unconventional petroleum resources increasingly important to the oil and gas industry. The term “shale gas” has largely become a catchall phrase to describe any unconventional plays that require fracturing, including shale gas, shale oil, tight gas, tight oil, and hybrid laminated reservoirs. With the emergence of these new sources of oil and gas, quantification of these resources has become a topic of major interest. The lack of much historical data, sparse sampling of shale formations, and a relative lack of understanding of unconventional reservoirs leads to large uncertainty in shale gas resource estimates. The Energy Resource Appraisal group of the ERCB has developed a methodology for quantifying the uncertainty in shale gas resource estimates in a geostatistical, data-driven framework that accounts for as many sources of uncertainty as possible.

Data Used for Shale Gas Potential

A variety of data types are necessary to fully characterize a shale gas reservoir. Roughly grouped, they are:

- Geological picks: The depth to the top and base of the shale unit and the gross thickness of the shale unit are necessary to build the geological framework for an area under study. The framework defines the volumetric extents of a reservoir in three dimensional space.
- Log analysis: The thickness of net reservoir shale, porosity of the shale, and total organic carbon (TOC) content of the shale fill in the geological framework with properties that describe the capacity of the reservoir to hold petroleum. Other properties such as water saturation may be calculated from log analysis in some cases where sufficient logs are available.
- Isotherm analysis: Langmuir isotherm parameters describe the relationship between TOC content, pressure, and the adsorbed gas carrying capacity of shale.
- Mineralogy (XRD/XRF): Grain density in a formation is driven by variations in mineralogy. Small fluctuations in grain density have a larger impact on density-derived porosity in shale than in more porous sandstone and carbonate reservoirs.
- Maturity information: Kerogen type, vitrinite reflectance (from organic petrography), and hydrogen index (from RockEval analysis) are used to determine whether a shale reservoir contains oil, condensate, gas, or some mixture.
- Reservoir data: Depth-pressure and depth-temperature relationships are determined from wells already drilled in a shale unit or from nearby conventional wells in communication with the

shale. Fluid properties such as compressibility and formation volume factor are also be taken from early well tests or analogs.

- Saturation information: Water, oil, and gas saturations are determined by Dean Stark analysis.

Methodology

The resource modelling methodology developed by the ERCB involves five primary steps:

1. Map the spatial variables. Those variables that are sufficiently dense are geostatistically simulated to account for the spatial uncertainty. Depth, thickness, porosity, and TOC have been spatially mapped for several shale units currently under study. Other variables, such as vitrinite reflectance and hydrogen index, need to be mapped to account for the oil and gas windows seen over large areas but cannot be directly simulated due to insufficient data.
2. Calculate the dependent variables. Some information is not available in sufficient quantities to allow direct modelling, but does show a significant relationship to the mappable variables. Reservoir pressure and depth both have linear relationships to depth. The Langmuir parameters that are used to calculate adsorbed gas content are dependent on TOC. Gas compressibility and oil formation volume factor are dependent on pressure. These relationships are modelled using regression, and uncertainty in the slope and intercept is calculated.
3. Calculate the other variables. Some variables are so sparse in early appraisal of shale gas resources that no major spatial or bivariate relationships can be determined. Univariate distributions are built for each of these variables and values are drawn. These variables include water saturation, gas-oil ratio and condensate-gas ratio for different maturity zones. Variable cutoffs for vitrinite reflectance and hydrogen index that define zone boundaries are also used to account for uncertainty in the immature, oil, and gas windows.
4. Calculate resources based on the data available on a section-by-section basis. The resources are summed at a township or assessment unit scale.
5. Simulate all variables. Values are drawn from the distributions of uncertainty and the resources are calculated for these particular values (each run is called a realization). This is repeated many times (typically 1000) and the resources are calculated over the entire area of interest, assessment units, and townships for each simulated realization.

Once simulation is completed the petroleum resources in place can be summarized for entire formations, assessment units, or townships. The uncertainty in resources is determined from the results of the simulation, giving a non-parametric output distribution. This type of distribution is usually summarized by a best case value, high case value, and low case value. Figure 1 shows a simplified schematic of the workflow.

This methodology is meant for early appraisal and gives values for petroleum initially in place. The evaluation of a specific shale unit will vary slightly depending on the quantity and quality of data that is available. Recovery factors could be applied to determine recoverable resources or reserves once sufficient wells have been drilled in the shale under study, or if analogs are judged to be similar enough to warrant application.

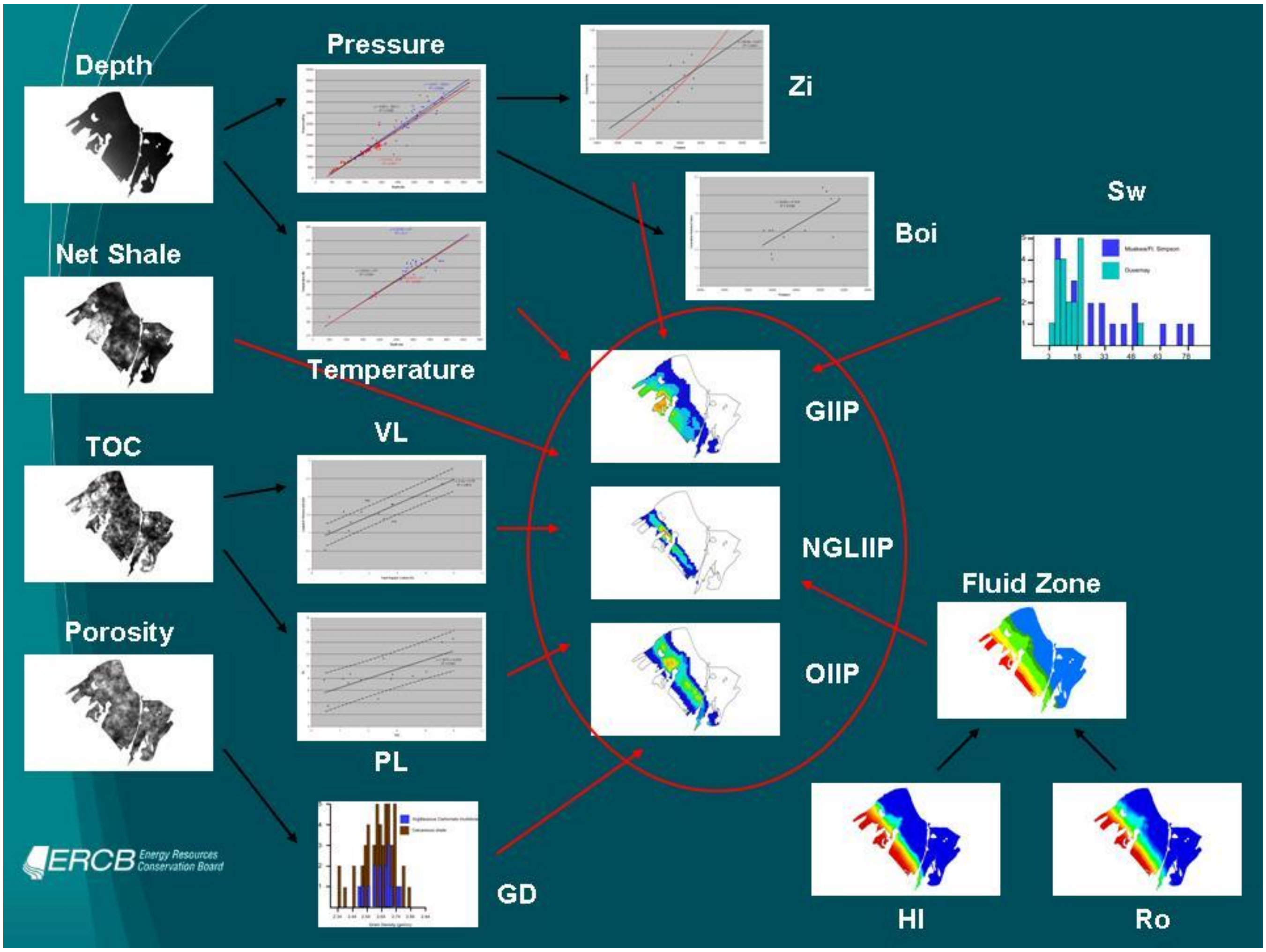

Figure 1: Simplified schematic view of the resource estimation workflow.

Conclusions

The workflow that has been developed is data-driven and focuses on quantifying uncertainty at every step. A large variety of data sources are considered and accounted for in several different ways. Wherever possible in the workflow, relationships between different variables are accounted for. The final result is a non-parametric distribution of petroleum initially in place describing the full range of joint uncertainty.

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