PRACTICAL WORKFLOWS FOR RESERVOIR MODELING

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Summary

The application of geostatistical modeling techniques for describing petroleum reservoirs has grown from relative obscurity to common practice over the past decade. Computing power, coupled with software commercialization, has contributed to the growth of the technology from its original 2D mining applications, to a rich suite of 3D methods for modeling geologic facies and distributing rock properties. Methodologies now include simulation techniques that strive to reproduce the variability of the original data and provide measures of uncertainty through the construction of multiple equal-probable realizations. A single realization can accurately describe the heterogeneous character associated with many petroleum reservoirs, upscaled, and be passed directly to multiphase fluid flow simulators for engineering assessment. Multiple realizations can be compared with one another in order to measure uncertainty, and summarized to provide input for risk analysis and probability mapping.

Introduction

This paper examines some of the common problems in applying stochastic models to real reservoirs. Case studies from a variety of producing reservoirs are reviewed, each expressing a different kind of practical problem to overcome. Facies boundary conditions, non-stationarity, and integration of multiple depositional environments are

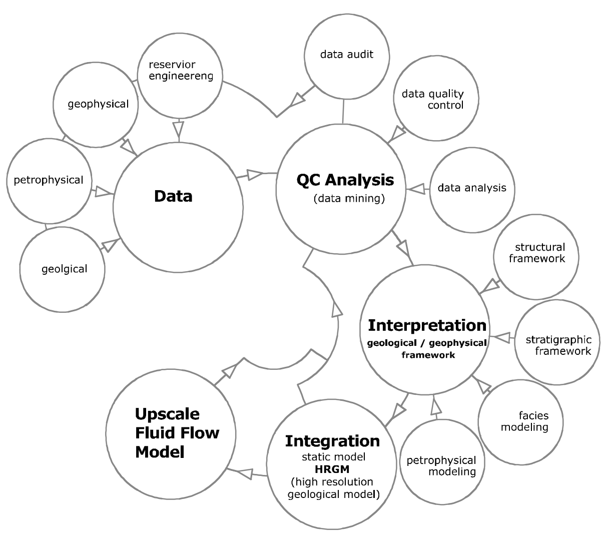

Figure 1. General workflow (Yarus and Chambers 2000)

some of the issues that are addressed here. Workflows describing the process needed to resolve these problems are presented. The general workflow applicable for most geostatistical reservoir characterization studies is shown (Fig. 1).

Facies Boundary Conditions.

The relationships among depositional facies in a heterogeneous reservoir can be critical in understanding fluid flow. Just as their occurrences are not arbitrary, neither are their interactions or their petrophysical characteristics. Reservoir models that preclude depositional facies or lithofacies will almost certainly fail to capture reliable information critical to fluid flow simulators, particularly when there are abrupt changes in petrophysical properties across facies boundaries.

When facies are simulated, the types of boundary conditions modeled are also important. Some facies have natural horizontal and vertical relationships created by depositional processes. Quantifying these relationships and using them as conditions in stochastic models is often overlooked. While object and pixel based methods can be used effectively, they require rules such as prior probabilities or objective functions in order to guarantee geologically plausible results. However, the depositional facies information is not always readily available for each well. Under such circumstances, non-depositional facies or lithofacies are used. Lithofacies are derived from log properties partitioned into discrete sets using either linear or non-linear methods, often resulting in an implied order (e.g. sand, shaly sand, shale). While lithofacies are often related to depositional facies, there is no guarantee that they will preserve true boundary conditions. For example, the log properties for channel splays and point bars can overlap, obscuring their individual geometries. If these geometries are important to reservoir flow, a higher degree of uncertainty may occur when lithofacies are used in the modeling process.

Further, simulation algorithms differ with respect to the underlying assumptions regarding discrete variables and cannot be selected “willy-nilly.” For example, sequential indicator simulation does not guarantee a defined relationship. In fact, in order to produce a spatial model honoring the covariance and cross variance, the facies indicators are usually assumed to be independent (Galli 1994). Truncated gaussian simulation assumes facies indicators are ordered, thus having a strong dependency (Matheron 1987).

Numerous algorithms and conditioning techniques are available for preserving facies boundary conditions, and knowing when to apply them strongly depends upon the relationships among the reservoir facies and flow. Object based simulation (Matheron et al. 1987, Tjelmeland and Holden, 1992), multiple point statistical methods (Caers, 1999), plurigaussian simulation (Le Loc'h and Galli, 1997), vertical transition probabilities (Yarus, et. al., 1996), and vertical proportion curves (Beucher et al. 1992) are just a few of the methodologies available. A general workflow is presented for resolving issues surrounding boundary conditions (Fig. 2).

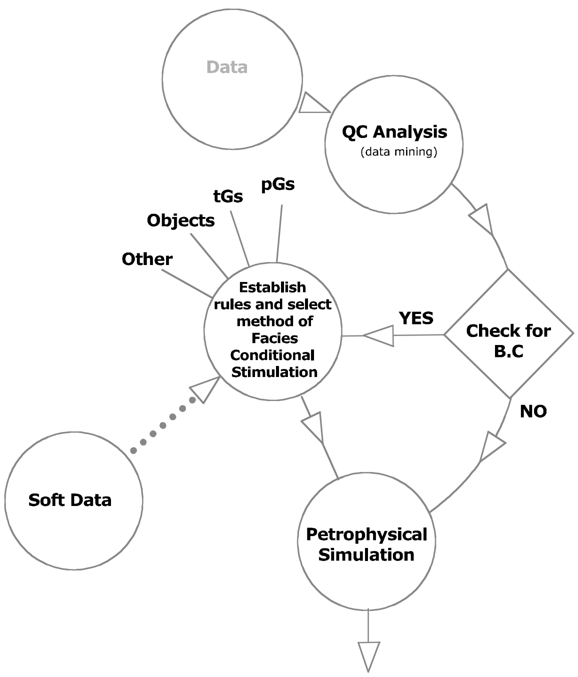

Figure 2. Workflow establishing methods for handling facies boundary conditions

Non-stationarity

Most petroleum reservoirs exhibit variability horizontally and vertically. For example, a particular facies can be present in one part of a reservoir and not in another. Simulating such reservoirs without accounting for this type of effect can lead to problems resulting in an inaccurate representation of the reservoir heterogeneity. For example, porous and permeable facies can be misplaced in the reservoir. While the experienced practitioner may be familiar with the problem of non-stationarity and the need to rectify this situation, less experienced modelers are often unaware of the problem and its implications.

The condition of stationarity is often misunderstood and actually is quite specific, referring to "local" stationarity - occurring within the search neighborhood (Isaaks and Srivastava 1989). In reservoir characterization studies, wells are often widely spaced and require a geographically large search neighborhood to insure that enough data are gathered to provide an accurate mean value. Under such circumstances, the risk of non-stationarity increases and estimates may no longer share the properties of unbiasedness and minimum estimation variance with the model. Overcoming non-stationarity ultimately results in modeling the trend, removing it, estimating or simulating the residuals, and replacing the trend. This can be done using methods such as Universal Kriging, Kriging with a trend, Kriging with an external drift, or Bayesian Kriging (Isaaks and Srivastava 1989, Deutsch and Journel 1998). Alternatively, non-stationary data can be modeled using stationary random functions coupled with constraining parameters such as objective functions or proportion curves that modify local estimates with secondary data (Volpi et. al. 1997). A workflow for managing non-stationary data is presented (Fig. 3).

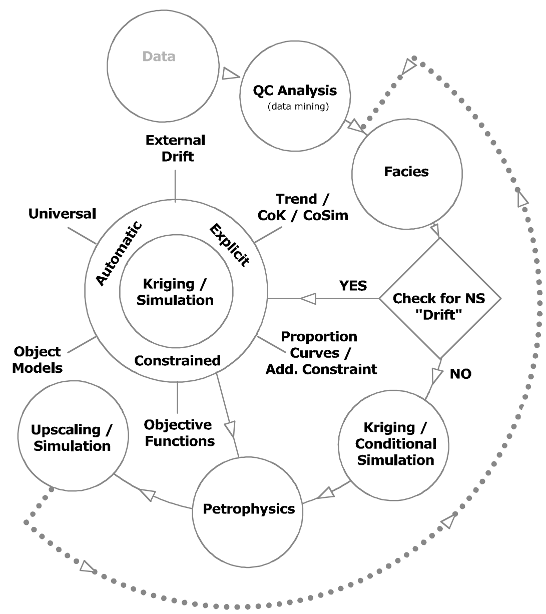

Figure 3. Workflow establishing methods for handling non-stationarity

Integration of multiple depositional environments

Petroleum reservoirs are often combinations of multiple depositional environments brought together as a result of deposition, erosion, or faulting. Problems can arise when modeling is oversimplified by attempting to use a single estimation or conditional simulation technique. Such complex reservoirs often require that specific methods be applied to geographically restricted areas or zones, then merged. The use of a single methodology may not resolve the effects of non-stationarity, misrepresent boundary conditions among facies, and use a set of spatial models that are not reasonable for the entire reservoir. For example, large-scale facies transitions in a prograding or retrograding shallow marine sequence are often best modeled using a truncated gaussian simulation method. In addition, different modeling techniques are often used together to preserve the multiple levels of heterogeneity within the facies architecture. For example, inside a transitional facies generated by truncated gaussian simulation, the sub-facies architecture can be modeled using object methods or Boolean sets (Matheron et al. 1987, Tjelmeland and Holden 1992) or multiple point statistic methods (Caers et al. 1999).

The process of constructing such a complex model requires careful thought and time. Each sequence or parasequence may require separate simulations tailored to their individual characteristics. Some sequences may require the introduction of soft data such as attributes from reflection seismic surveys. Once the individual simulations are constructed, they are merged in order to achieve the final static model of the reservoir. The final step is to produce and rank multiple realizations of each sequence for uncertainty analysis. This critical task is too often treated superficially and grossly underestimated in terms of time and cost particularly in complex models. Although the process is often automated, requiring less human intervention, computational time and file storage capacity can become a serious factor very quickly. The workflow for modeling reservoirs comprised of coalescing, overprinted, or faulted sequences is presented (Fig. 4).

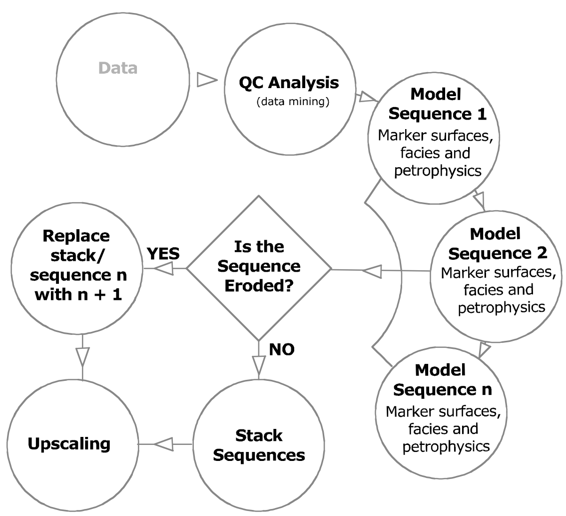

Figure 4. Workflow establishing methods for handling integration of multiple depositional environments

Conclusions

Stochastic simulation methods have evolved to a level of sophistication that allows for geological information to be captured and integrated into sophisticated 3-D computer models. The process is often more complex than some may initially realize. Boundary conditions between facies, local trends, and coalescing and/or overprinting of depositional environments present common challenging problems often overlooked. The workflows presented here address some of the common modeling problems encountered in reservoir characterization. They are not intended to be rigid instructions, but general guidelines that assist in avoiding pitfalls. Each geoscientist faced with modeling a reservoir has a wide variety of tools from which to choose. These tools must be used to resolve key issues such as those discussed here that may significantly influence reservoir production. The real challenge is to apply them pragmatically in order to solve problems with an appropriate level of accuracy, and remain cost effective.

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