Multivariate Geostatistical Techniques to Build Mechanical Earth Model: Case Study

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To increase the accuracy of reservoir characterization, all possible sources of uncertainty should be included in modeling. This includes geological uncertainty. Geostatistical techniques are used to build multiple equi-probable geological realizations. Using transfer functions (e.g. flow and geomechanical simulators) these realizations can be used to assess the effect of geological uncertainty on dynamic responses such as flow and geomechanical responses of media. In the case of conventional flow simulation, petrophysical properties (porosity, permeability and saturation) are required for reservoir performance assessment. However in the case of coupled geomechanical flow simulation, rock mechanical properties such as elastic and plastic properties are another group of properties which should be modeled stochastically to better characterize reservoir performance uncertainty. A Mechanical Earth Model (MEM) is a comprehensive geological model which includes both petrophysical and rock mechanical properties Steam Assisted Gravity Drainage (SAGD) is the most common in-situ recovery processes in Athabasca Oil Sands (McMurray formation) of Alberta-Canada. It has been shown that geomechanics has a significant impact on SAGD performance. Considering multiple MEM realizations rather than a single deterministic model as with conventional geomechanical models allows for the assessment of uncertainty regarding geomechanical effects on SAGD process. In this study, multivariate geostatistical techniques have been used to build multiple MEM realizations for McMurray formation, forone of oilsand fields of western Canada.

1. Introduction

The McMurray formation is located northwest of Fort McMurray, Alberta-Canada and spans 40000 km^2. The formation contains an estimated 174.4 billion barrels of bitumen (Polikar, 2004). Surface mining can access approximately 10% of reserves located close to the surface; however the remaining 90% of reserves are only accessible through in-situ recovery technologies. Among all in-situ recovery techniques, Steam Assisted Gravity Drainage (SAGD), developed by Roger Butler (Butler, 1998) has been found to be the most effective.

A SAGD pad considers multiple horizontal well pairs drilled up to 1000 m long. The distance between upper injection well and lower production well is usually about 5m. After 3 to 6 months of steam injection through both wells to initiate inter-connectivity, steam continues to be injected through the upper injection well only. Oil can be produced from the lower horizontal well. Cumulative Oil Production (COP) and Steam Oil Ratio (SOR) are two parameters which are usually used to evaluate the production performance of SAGD.

Although many parameters have an effect on SAGD performance, reservoir geology and heterogeneity distribution of facies and inherent properties are the most significant (Mclennan and Deutsch, 2004).Geostatistical techniques could be used to quantify uncertainty in geological model through construction of multiple equally probable realizations of reservoir properties and the difference between the performance of geological realizations is a measure of geological uncertainty (Deutsch et al., 2002). Each geological realization is a combination of a structural model, facies model and property models. In the case of conventional flow simulation, in which geomechanical effect is negligible, petrophysical properties are the only group of parameters which are required to be modeled stochastically. These properties, i.e. porosity, permeability and water saturation, are used in fluid flow governing equations and the geological uncertainty is transferred to production uncertainty, i.e. uncertainty in production variable such as COP and SOR, by passing each realization through a flow simulator.

The oilsand in the McMurray formation has an in-situ interlocked fabric (Dusseault and Morgenstern, 1978). Several experimental (e.g. Dusseault and Morgenstern, 1978, Chalaturnyk, 1996 and Touhidi-Baghini, 1998), and numerical studies,(e.g. Li, 2006, Chalaturnyk, 1996 and Azad, 2012),have been done and it has been shown that geomechanics has a significant effect on SAGD process and coupled geomechanical flow simulation should be considered to investigate the geomechanical effects on recovery for SAGD processes. Elastic and plastic properties play the same role for rock mechanical governing equations as petrophysical properties play for fluid flow governing equations. These rock mechanical properties, i.e. elastic and plastic properties, have the same characteristics as petrophysical properties and could be modeled stochastically.

Khajeh et al. (2011) investigated the effect of considering heterogeneous rock mechanical properties for coupled geomechanical flow simulation of SAGD on output variables of flow (COP and SOR) and geomechanics (vertical

Displacement Profile (VDP)). They concluded that considering comprehensive geological models which include both flow and rock mechanical properties as heterogeneous maps instead of assuming homogeneous, layer cake, models for these properties, results in wider ranges of uncertainties and accordingly results in making more accurate decisions which should be made based on these types of analysis.If precise management of geological uncertainty is of interest coupled geomechanical flow simulation of SAGD should be used.

In this work and with the help of available data from one of Western Canadian oilsand reservoirs, multiple realizations of MEM will be generated using multivariate geostatistical techniques. These MEM realizations are going to be considered in coupled geomechanical flow simulation of SAGD process and to check/validate proposed numerical upscaling technique for elastic properties. Therefore, elastic properties (bulk modulus and shear modulus) are the only group of rock mechanical properties considered for this study.Due to confidentiality issues, the coordinates of wells are transformed to range of 0 to 10000 *m in easting (X) direction and 0 to 5000 m in northing (Y) direction.*

The main steps to reach to this purpose are:

- Data preparation, stratigraphicaltransformation and upscaling
- Gridding
- Structural modeling
- Statistical data analysis
- Facies modeling
- Property modeling (petrophysical and elastic properties)

These steps will be explained in the following sections.

2. Data preparation, stratigraphicaltransformation and upscaling

The data set used for this study was picked from a SAGD operation area in Athabasca Oilsand area. Conditioned data used for this study are digital well log data. In Figure 1, location map of these wells is shown.

Dipole sonic and bulk density logs (Δt_c, Δt_s and ρ_b) are types of logs which are required for calculation of elastic properties. Equations 1 and 2 show Poisson's ratio (ν) and Young Modulus (E) formulation as a function of Δt_c, Δt_s and ρ_b respectively.

$$\nu_d = \frac{0.5\left({}^{\Delta t_s}/_{\Delta t_c}\right)^2}{\left({}^{\Delta t_s}/_{\Delta t_c}\right)^2 - 1} \qquad \text{Eq (1)}$$

$$E_d = \frac{\rho_b}{{\Delta t_c}^2}\frac{(1-2\nu_d)(1+\nu_d)}{(1-\nu_d)} \qquad \text{Eq (2)}$$

In which;

ν_d: Dynamic poisson's ratio

E_d:Dynamic young modulus

Δt_s: Shear wave transformation time

Δt_c: Compression wave transformation time

ρb: Bulk Density

By having two elastic properties the other elastic properties could be generated. Bulk modulus (K) and shear modulus (G) are our interested elastic properties for this study and in Equations 3 and 4 formulations of these two parameters as a function of young modulus (E) and poisson's ratio (ν) are shown.

$$K = \frac{E}{3(1-2\nu)} \qquad \text{Eq (3)}$$

$$G = \frac{E}{2(1+\nu)} \qquad \text{Eq (4)}$$

In addition to these three logs, effective porosity information was also available. This information was available at intervals of 0.125 m. From the log analysis dynamic elastic properties will be obtained which are generally 2 to 5 times larger than static elastic properties. In reality and for simulation purposes, static elastic properties should be considered instead of dynamic ones. For calibrating dynamic elastic properties and to move from dynamic to static propertiesfurther information, e.g. experimental lab test results, is required. Due to lack of data, no calibration has been performed here.

No facies information was available. Two pseudo facies of *Sand* and *Shale* have been defined based on the cutoff on porosity values. For that purpose, first data are transformed to stratigraphical unit and then upscaled to 0.5 m interval. Statistical information between upscaled scale, 0.5m, and original scale, 0.125m, was checked for all attributes to make sure that there is no significant change in transformation of data from fine scale to upscaled scale. Facies with the value of porosity lower than 0.07 are considered as shale (Facies No. 0) and facies with the value of porosity more than 0.07 are considered as Sand (Facies No.1). Figure 2 shows histograms of porosity and facies after transformation of data to stratigraphical unit and upscaling to 0.5 m intervals. An average of 80% Sand facies and 20% of shale facies are obtained based on this facies definition.

After facies modeling, porosity, bulk modulus and shear modulus are the attributes of interest for geostatistical modeling in this work. In the case of high correlation between variables, in all reservoirs modeling there is a need to model the joint distribution of multiple variables (Deutsch, 2002) and conventionally they should be modeled in a sequential fashion. For that purpose it is first necessary to check the correlation of initial data set. Figure 3 shows correlation coefficient matrices between porosity, bulk modulus and shear modulus for sand (left) and shale (right) facies respectively.As could be seen, the correlation coefficient between porosity and elastic properties is low and accordingly these properties are modeled independently.

2. Gridding

Considering an appropriate gridding system is the primary step of each geological modeling process. The first consideration is that the model should be suitable for specific project goals. The second consideration is that important features, such as boundaries, fault, Lithofacies and property changes, can be resolved with the final model and the third consideration is the resolution should be in such a manner to ensure a meaningful scale up from geological model to simulation model (Deutsch, 2002).

A very fine gridding system has been considered. An aerial dimension of 100 m by 100 m from the center of zone shown in Figure 1 has been selected and 1m by 1m grid size has been considered for this area. All further geostatistical modeling has been performed for this zone. For vertical resolution, 0.5 m thickness has been selected. One goal of this work is to assess the impact on performance for upscaled results, therefore the small block size is considered.

3. Structural Modeling

Knowing about geological framework prior to geostatistical modeling is essential. Reservoirs are made up of a number of reservoir layers and each layer corresponds to a particular time period. Each stratigraphic layer is modeled independently and at the end the models will be merged to each other to provide geological models of whole reservoir. Generally McMurray formation is subdivided in three units which are; lower, middle and upper units. Other subdivisions are also considered based on different purposes which are not as common as mentioned subdivision. In this study, whole McMurray formation is considered as single zone.

Before performing any geostatistical estimation/simulation, there is a need to quantify spatial correlation of data. Variogram calculation provides a positive-definite correlation between data for all distances and in any direction.

To find spatial correlation of top and bottom surfaces, first data are transformed to normal score units. Experimental and fitted theoretical 2D (areal) variograms used to generate top and bottom surfaces are shown in Figures 4 and 5 for top and bottom surfaces respectively.

With the help of top and bottom markers, available from provided data set for this study, and variogram model, McMurray top surface, bottom surface and isochore thickness have been calculated and shown in Figure 6. Global kriging was used to generate structural surfaces. As could be seen, thickness of considered section is between 67 to 72 m. for next facies and property modeling steps, 20 m thickness this zone is going to be modeled.

4. Statistical data analysis

Prior understanding of statistical characteristics of data variable is required for geostatistical modeling. Figures 7 and 8 show histograms of porosity, bulk modulus and shear modulus for sand and shale facies respectively.

5. Facies Modeling

Facies modeling should be done for subsequent property modeling. In McMurray formation, there is considerable difference between petrophysical and rock mechanical properties of sand and shale facies. Sequential indicator simulation technique has been used for modeling of pseudo defined shale/sand facies in this study. Assembling 3D variogram before geostatistical simulation to see spatial correlation for each facies type is required. As expected, horizontal variography is more challenging in comparison to vertical one which is due to lack of data in horizontal direction in comparison to vertical direction. Considering anisotropy ratio between vertical and horizontal variogram and/or using expert judgment are alternatives which are usually used for horizontal variography. Figure 9 shows horizontal (top) and vertical (bottom) variograms used for subsequent facies simulation process. Sequential indicator simulation (SISIM) from GSLIB package has been used for generating 100 realizations of shale/sand sequences. Areal dimension is 100m by 100m and 20m thickness from central part of McMurray formation is considered as area of interest. Figure 10 shows6 realizations in XZ direction at Y=51.These 100 facies realizations will be used for the next following property modeling step.

5. Property Modeling

Distribution of properties, both petrophysical and rock mechanical properties, has considerable effect on flow and geomechanical behavior of SAGD process (Khajeh et al., 2011). Property behavior is controlled by facies and it is necessary to do modeling by facies.

Porosity, permeability and water saturation are the petrophysical properties required to be modeled stochastically. Due to lack of data constant 15% water saturation is considered and synthetic permeability models were generated using the porosity realizations. A linear model was used for horizontal permeability modeling, fit to porosity.

Bulk modulus and shear modulus are two elastic properties which are considered for geostatistical modeling. Figure 3, there is low correlation coefficient between these properties and porosity and accordingly these properties are modeled independent to porosity.

The same steps mentioned for facies modeling, i.e. data preparation, variography, and simulation, should be followed for property modeling as well. Sequential Gaussian Simulation (SGSIM) from GSLIB package has been considered for generating 100 realizations of each property. For each simulated realization, propertiesare independently simulated assuming a single facies type; the results are then merged using facies models generated in previous step.

Variography should be performed for each property in each facies separately. Just as an example, in Figure 11horizontal (top) and vertical (bottom) variograms considered for porosity modeling in sand facies are shown. In Figures 12one MEM realization has been shown.

5. Conclusion

In this study, multiple realizations of comprehensive MEM instead of conventional geological realizations has been generated which results in more accurate uncertainty management for coupled geomechanical flow simulation of SAGD process. In the next step of study, i.e. simulation part, one of these realizations is going to be considered to compare efficiency of proposed numerical upscaling technique with power law averaging techniques for upscaling of elastic properties.

6. References

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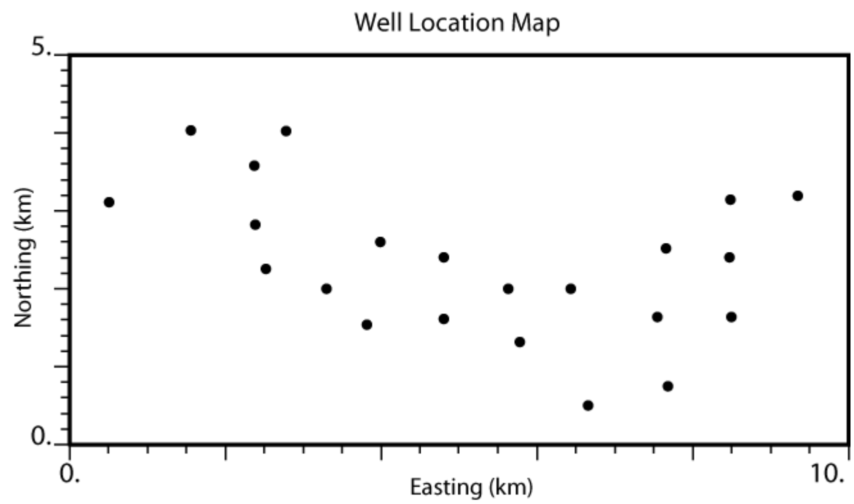

Figure 1. Location map of well data.

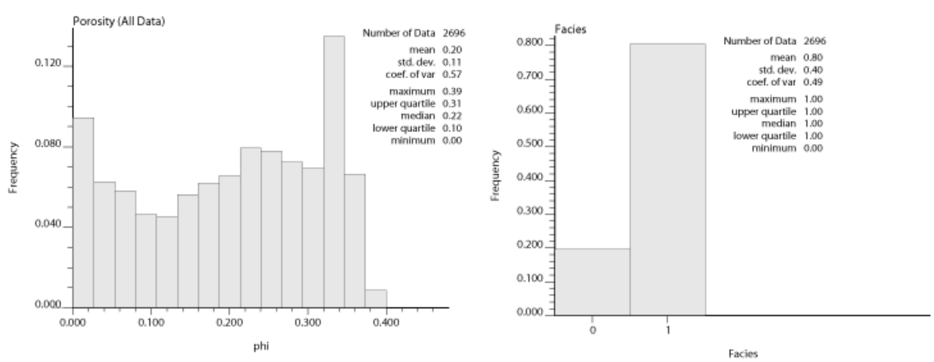

Figure 2. Histograms of porosity (left) and pseudo defined facies (right).

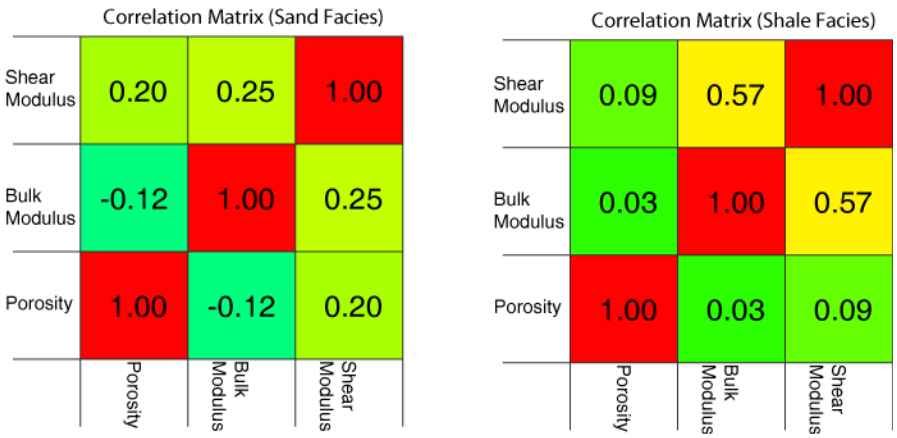

Figure 3. Correlation coefficient matrices for sand (left) and shale (right) facies.

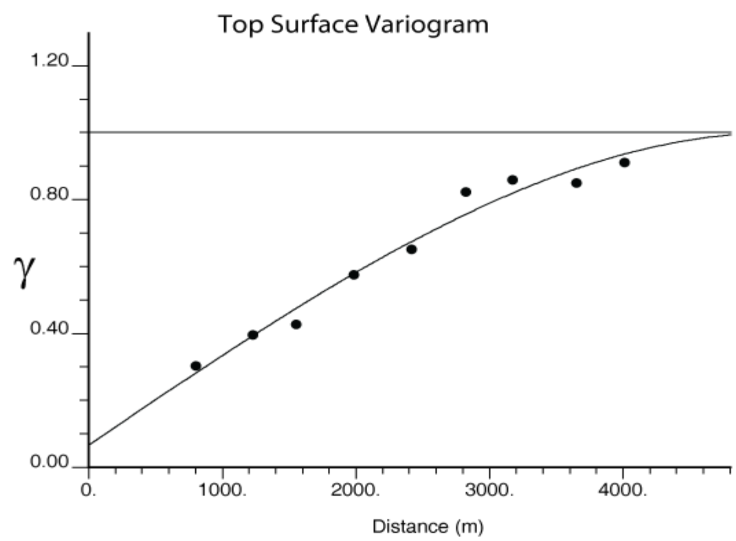

Figure 4. Experimental and fitted theoretical variogram of McMurray top surface.

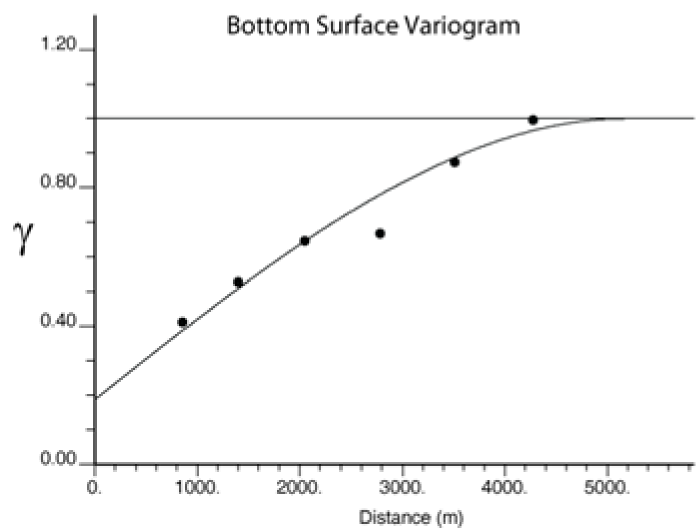

Figure 5. Experimental and fitted theoretical variogram of McMurray bottom surface.

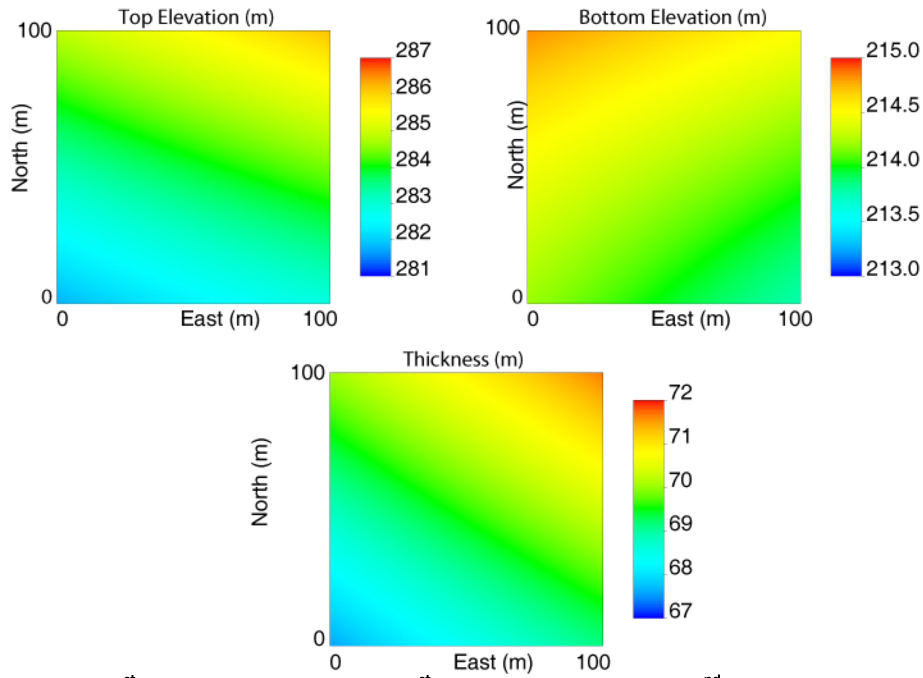

Figure 6. Top surface (1st row-left), bottom surface (1st row-right) and thickness (2nd row) map of area under study.

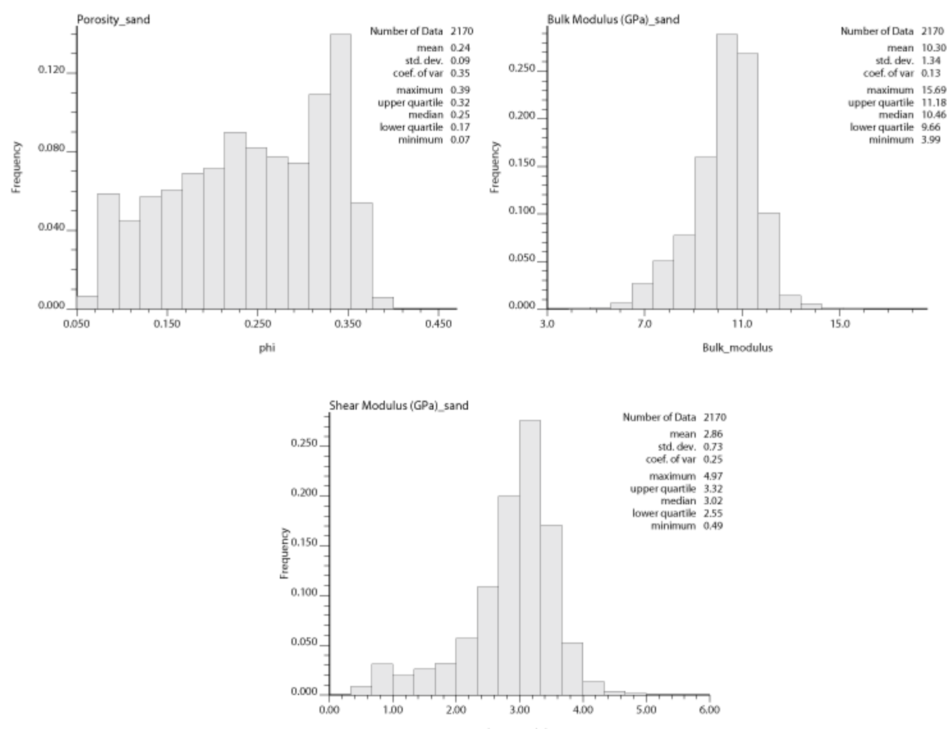

Figure 7. Porosity (1st row-left), Bulk Modulus (1st row-right) and Shear Modulus (2nd row) Histograms for Sand Facies.

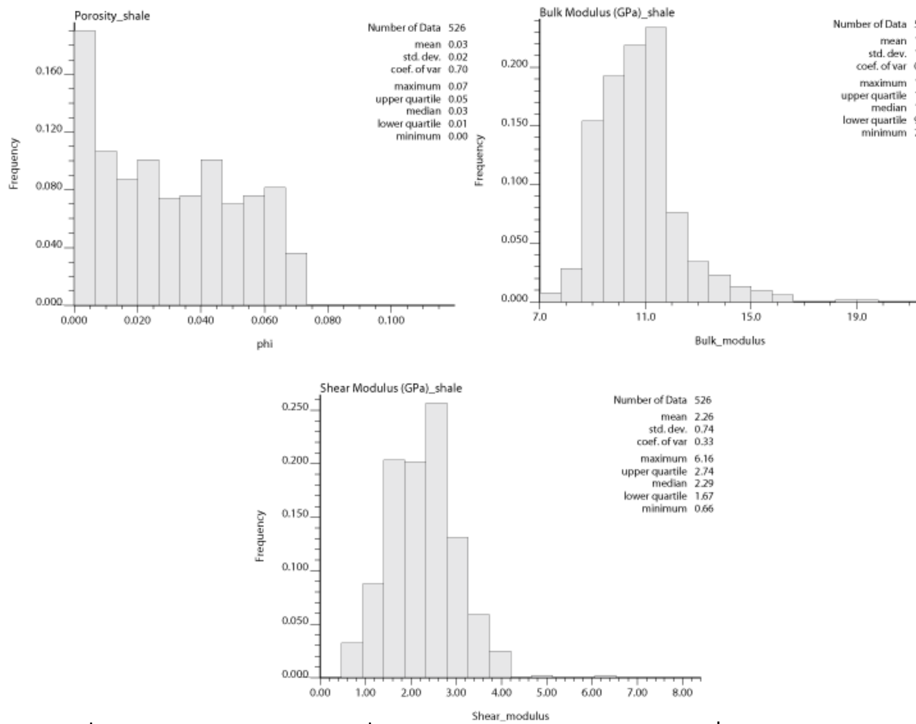

Figure 8. Porosity (1st row-left), Bulk Modulus (1st row-right) and Shear Modulus (2nd row) Histograms for Shale Facies.

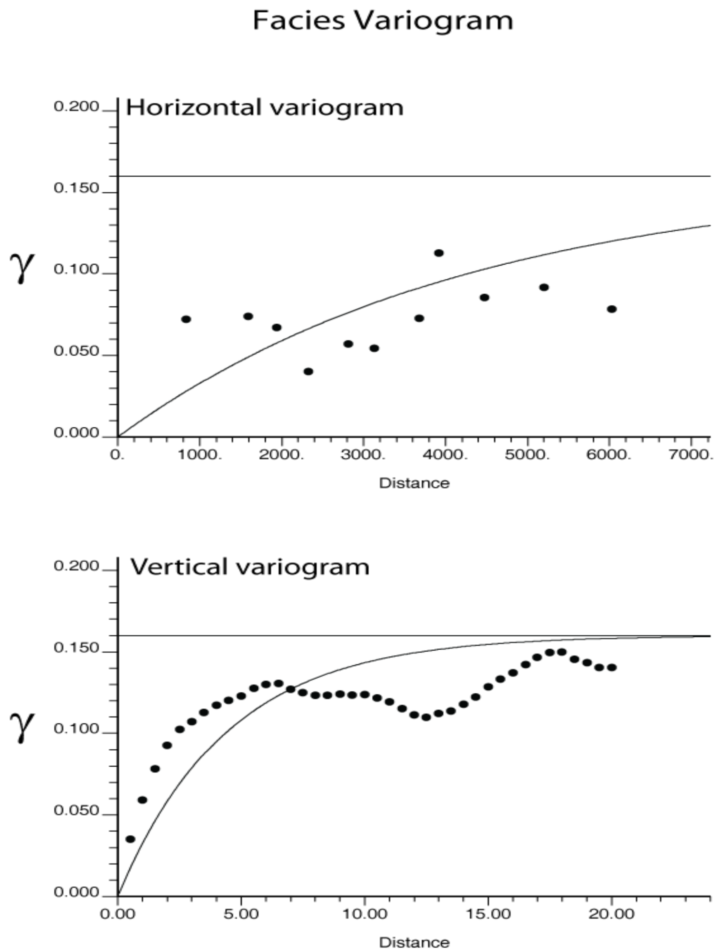

Figure 9. Horizontal (Top) and Vertical (bottom) indicator variograms used for facies modeling.

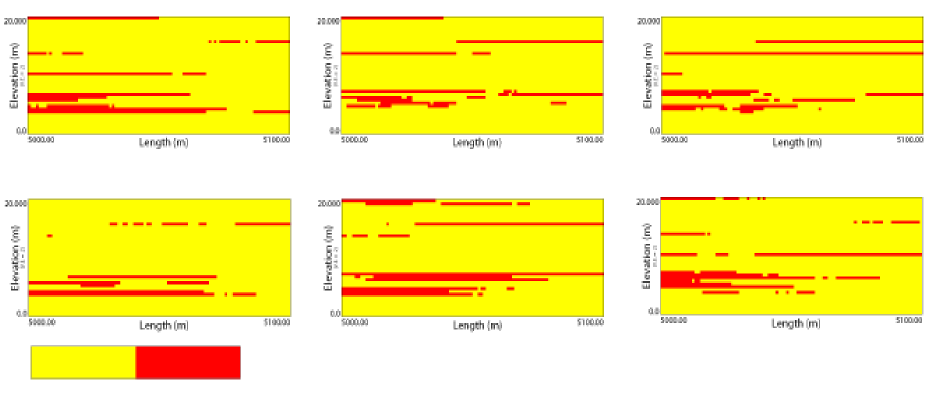

Figure 10. Six Facies Realizations in XZ direction for Y=51.

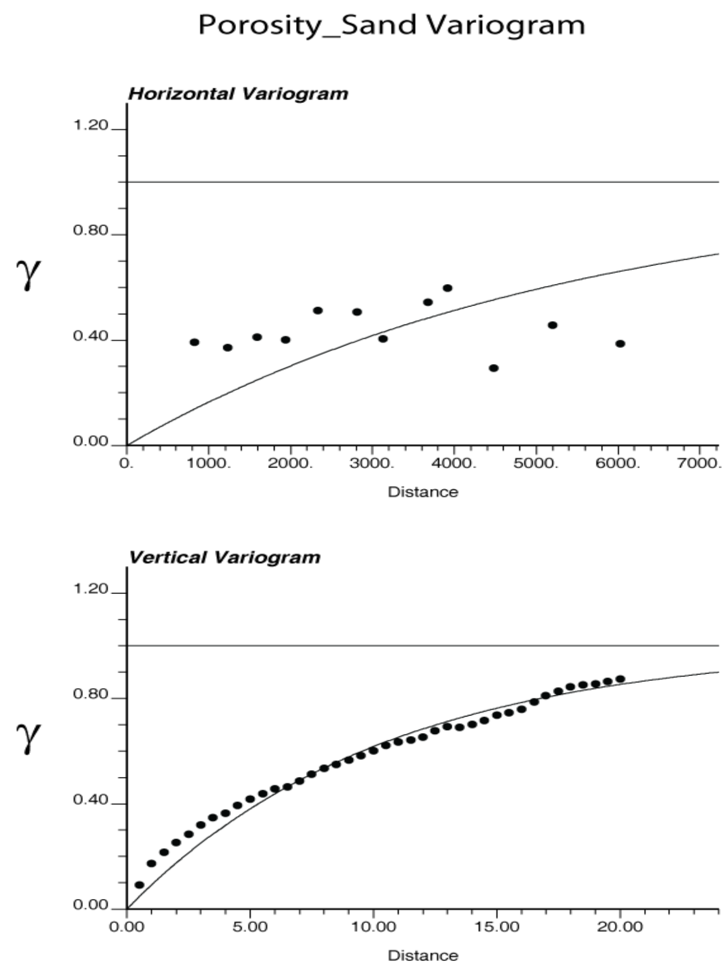

Figure 11. Horizontal (Top) and Vertical (bottom) variograms used for Porosity (sand facies) modeling.

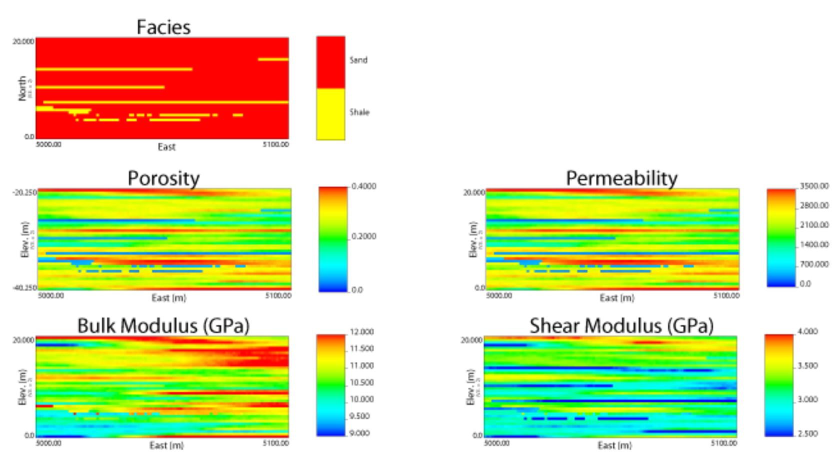

Figure 12. One MEM Realization