Author's Response

We appreciate all the comments provided by the reviewers. The responses will follow the format in which both reviewers presented their comments.

NB: Lines will be referred to as "L" in Author's Response (AR), General Comments as GC, and Author's Changes as AC

Reviewer 2

GC1: A paragraph with a detailed description of how GPM works would be beneficial to readers. This would fit well within the section title "Process Modeling in GPM".

AR1: We agree with this comment from the reviewer. Additional information on how geological processes in GPM^{TM} operate have been included in the manuscript.

AC1: Changes that have been made in the manuscript include:

Steady Flow Process

The steady flow process in GPM model flows that change slowly over a period; e.g. rivers at normal stage, and deltas. The steady flow process best depicts sediment transport scenarios where flow velocity and channel depth do not vary abruptly. The steady flow process settings can be specified to fit a task in the steady flow pane of the "run sedimentary simulation" dialog box in Petrel software (2017.1 version and above). To attain stability in the simulator before running the full simulation (i.e. entire depositional period), it is advisable to undertake preliminary runs to ascertain the appropriateness of the source intensity and flow behaviour. For steady flow, a boundary condition must be specified at the edges of the model. In an open flow system, negative integers (i.e. values below zero) should be assigned to the edges of the hypothetical paleo-surface to allow water to enter and leave the simulation area. Further information on the steady flow settings can be located in the GPM user manual (i.e. Guru in the Petrel software).

Unsteady Flow Process

The unsteady flow process simulates flow that are periodic, and run for a limited time; example, in turbidites where velocity of flow and depth changes abruptly over time. The unsteady flow process involves fluid elements that are affected by gravity, and by friction against the hypothetical topographic surface. A previous study on the use of unsteady flow process for stratigraphic simulation is outlined in Otoo and Hodgetts, (2019).

Diffusion Process

The diffusion process replicates sediment erosion from areas of higher slope (i.e. source location), and deposition to lower slope sections of the model area. Sediment dispersion is carried out through erosion and transportation processes that are driven by gravity. The diffusion process follows an assumption that sediments are transported downslope at a proportional rate to the topographic gradient; therefore making fine grained sediments easily transportable than coarse grained sediments. The diffusion process is controlled by two parameters; (i) diffusion coefficient, which controls the strength of the diffusion, and (ii) diffusion curve that serves as a unitless multiplier in the algorithm. The mathematical equation for the diffusion geological process is:

$\frac{\partial z}{\partial t} = k\nabla^2 \mathrm{z}$, where **z** is topographic elevation, **k** the diffusion coefficient, **t** for time, and $\nabla^2 \mathrm{z}$ the laplacian.

Sediment Accumulation

This involves the deposition of sediment using an areal source location. In the GPM$^{\mathrm{TM}}$ software, sediment source can be set to a point location or considered to emanate from a whole area. For example, where a lithology is interpreted to be uniformly distributed, the sediment accumulation process can replicate such depositional scenarios. The areal input rates (in mm/yr) for each sediment type must be specified in the settings. Specifying the areal rates for each sediment is important because the software is configured to use the value of the surface at each cell in the model and multiplies it by a value (i.e. value from a unitless curve) at each time step in the simulation to estimate the thickness of sediments accumulated or eroded from the cell. Sediment accumulation can be expressed as:

GC2: Statistical validation of why the number of modelling scenarios were chosen would be good to include. For this to be reproducible (which should be the aim), anyone that reads this should have a clear idea as to why 20 scenarios were chosen so this method can be repeated in other studies.

AR 2: A major limitation in the FSM approach is that initial boundary conditions at the time of deposition, which is required for the simulation, are unknown. In our opinion, a better means to evaluate the stratigraphic scenarios selected should be the capacity of their resultant stratigraphic-based porosity and permeability property model to match known data.

AC2: An initial simulation (labelled figure 6a) was undertaken to see if the outcome will mimic the depositional pattern observed in the seismic section (figure 3b). The 20 scenarios were derived by using different input parameters with Figure 6a as guide.

GC3: I would advise the authors to not mention any ‘future studies’ or further work. This manuscript should stand alone and showcase the modelling methods presented rather than putting a final statement about what they want/are going to do in the future.

AR 3: The suggestion will be considered, and the necessary corrections made in the manuscript.

AC 3: Further explanations on how results were achieved in GPM and integrated into the property modeling workflow in Petrel have been included in the manuscript. In addition, the mention of future studies in the manuscript have been removed.

Line Comments (LC)

L14: “where” should be used instead of “were”

AR14: The appropriate word will be used in the manuscript.

AC14: The new statement reads “Reservoir modeling techniques with the capacity to integrate forward stratigraphic simulation outputs with stochastic modeling techniques for subsurface property modeling”

L15: “accommodation space” is not a widely accepted term anymore, instead please use “accommodation”.

AR15: The appropriate word “accommodation” will be used henceforth.

AC15: “Accommodation” has been used instead of “Accommodation space” anywhere it was found in the manuscript.

L6-10: These statements do not make much sense, even with the suggested revision by the author. I would suggest something like “Typically, reservoir modelling procedures require continued property modification until a satisfactory match to known subsurface data is achieved. However, acquisition of subsurface data is costly, thus prohibitive to data collection and reservoir model conditioning.”

AR 6-10: The suggestion has been accepted and incorporated into the manuscript.

AC 6-10: Typically, reservoir modeling tasks require continued property modification until an a appropriate match to known subsurface data is obtained. However, acquisition of subsurface datasets is costly, thus restricts data collection and subsurface modeling condition; hence reducing our perspective of reservoir property variation and its impact on fluid behaviour.

L 16: This is repeated throughout the manuscript, the statement ‘most likely’ does not fit with the assertions made in a scientific manuscript. Integration of FSM’s with stochastic modelling techniques will improve reservoir characterisation because they more accurately simulate the geology than other methods.

AR 16: We agree with the reviewer’s suggestion, and will make the changes in the manuscript.

AC 16: The correction will be made to read “Reservoir modeling techniques with the capacity to integrate forward stratigraphic simulation outputs with stochastic modeling techniques for subsurface property modeling will improve reservoir heterogeneity characterization, because they more accurately produce geological realism than the other methods (Singh et al. 2013)”.

L 41: I presume the author means ‘tidal’ processes. If so, “tidal” is a more appropriate term to use in this instance.

AR 41: The appropriate changes will be made to conform with the reviewer’s comment.

AC 41: complex depositional architecture of waves, tidal and fluvial processes; suggesting that a single.

L 73: “twenty four suite of well data” should be changed to something like: “and a suite of 24 wells that comprise of..”

AR 73: We agree with the suggestion, and will make the corrections in the manuscript.

AC 73: Datasets include 3-D seismic data, and a suite of 24 wells that consist of formation pressure data, core data, and sedimentological logs.

L 76: The author states that a variety of geological features (grain size, sedimentary structures etc.) “play a significant part of reservoir petrophysics”. This is an important statement given the nature of the study, but this point should be elaborated. A sentence is all that is needed.

AR 76: Grain composition, and structure does control petrophysical attributes in a reservoir, hence some additional explanation to make the statement clearer.

AC 76: Grain size, sediment matrix and the degree of sorting generally controls the volume of voids created in a sedimentary formation, and therefore the porosity and permeability attributes.

L 101 & 106: The second sentence should start with “For example..” and Remove “space” from “accommodation space” – ‘space’ is implied in ‘accommodation’ respectively.

AR 101 & 106: The corrections will be made as suggested.

AC 101 & 106: As indicated previously, “Accommodation space” has been replaced with “Accommodation” in the manuscript.

L 108: This sentence should be broken into two, there isn’t a need for a semicolon. In fact, I would recommend that the manuscript be carefully reviewed to exclude semicolons as they create long sentences.

AR 108: The suggestion is accepted, and the relevant changes will be done.

AC 108: Sediment deposition, and its response to post-depositional sedimentary and tectonic processes are significant in the ultimate distribution of subsurface lithofacies units. To attain stratigraphic outputs that fall within the depositional architecture interpreted from the seismic data, the input parameters were varied (see Table 2).

Lv164: I am not sure the correct figure is cited here. Should it be Fig. 4d?

AR 164: Figure 4d is the hypothetical topographic surface that was used to generate the “best fit” stratigraphic model in Figure 5d. So figure 5d as used in the manuscript is the appropriate figure.

L164: As a result, no changes will be made to this comment.

L 164-166: This statement needs a reference. Which shallow marine depositional sequence? The one presented by Folkestad and Sature (2006)? If so, please note the appropriate reference.

AR 164-166: We are agree, and will provide the references to support this statement.

AC 164-166: This is because, when compared to depositional description in studies such as Folkestad and Sature (2006); kieft et al., (2011), it produced a stratigraphic sequence that mimics the depositional sequence in the shallow marine depositional environment under study.

L 176-178: This sentence should be condensed. Careful attention should be paid to grammatical errors and misspellings.

AR 176-178: The comment has been considered and corrections made.

AC 176-178: For example, shoreface lithofacies units were characterized using medium-to-coarse grained sediments, which accumulates at proximal distance to the sediment source. In contrast, mudstone units are associated to fine grained sediments that accumulate at distal section of the simulation domain.

L 180-183: This sentence needs to be condensed. High N/G zones are known to be the best reservoir quality zones/units. Instead focus on what those zones are from the previous work and data.

AR 180-183: In line with the reviewer's comment, appropriate changes will be made in the manuscript.

AC 180-183: In previous studies on the Sleipner Øst, and Volve field (e.g. Equinor, 2006; Kieft et al., 2011), Shoreface deposits were identified to make up the best reservoir units, whilst lagoonal deposits formed the worst reservoir units. Using this as guide, shoreface sandstone units and mudstone/shale units in the forward stratigraphic model were characterized as best and worst reservoir units respectively.

L 184: Replace "Statoil" with "Equinor"

AR 184: We agree to the suggestion, and will make the corrections.

AC 184: Anywhere "Statoil" was used in the manuscript will be replaced with "Equinor".

L 195: Please change the current statement to '. . . extended to represent lithofacies. . .'

AR 195: The relevant modification will be done.

AC 195: The workflow (**Figure 2b**) used for subsurface property (e.g. lithofacies, and petrophysical) modeling in Petrel^{TM} is extended to represent lithofacies, porosity, and permeability properties in the forward stratigraphic model.

L 203: Please change the current statement to 'Typically, pillars join corresponding...' as there are more words than necessary.

AR 203: We are in agreement with the reviewer's comment, and will make the appropriate changes.

AC 203: Typically, pillars join corresponding corners of every grid cell of the adjacent grid to form the foundation.

L 205: This sentence should be condensed. For example, it's not necessary to include the nomenclature of 'corner point gridding' in this context.

AR 205: We agree with the reviewer on this comment, and will be the necessary changes in the manuscript.

AC 205: The sentence with respect to the fault directions has been modified into "The prominent orientation of faults (I-direction) within the model area trends generally in a N-S and NE-SW direction, so the "I-direction" was set to the NNE-SSW direction to align the grid cells.

L 211: This sentence should be broken up into two statements and a clearer definition of layers is required.

AR 211: The comment has been taken on-board, and will be included in the manuscript.

AC 211: Vertical layering on the other hand defines the thicknesses and orientation between the layers of the model. Layers in this context describes significant changes in particle size or sediment composition in a geological formation.

L 212: What is the cell thickness? Are they constant across the model? How were they defined to control the vertical scale?

AR 212: A constant cell thickness of 1 (one) was used. This was done to attain an identical thickness as that generated from the stratigraphic simulation in all zones.

AC 212: Using the vertical layering scheme makes it possible to honour the fault framework, pillar grid and horizons that have been derived in the model.

L 215: What is meant by ‘finer’ cells? Please be more precise with the scale you are referring to. Porosity and Permeability Modelling.

AR 215: The use “finer cells” is to describe cells with smaller dimension. However, it has been modified to make it more meaningful to readers of this manuscript.

AC 215: The statement has been changed into: “ Upscaling: involves the substation of fine grid cells with coarser grid cells. This is done to assign property values to cells in order to evaluate which discrete value suits each a selected data point. One advantage of the upscaling procedure is to make the modeling process faster.

L 223: What is the original cell size if it was compressed by 75%? This statement is unclear.

AR 223: The original cell size from our deduction is 143 m x 133 m x 84 m.

AC 223: The statement has been revised into “The original petrophysical model has a grid dimension of 108 m x 100 m x 63 m, and is compressed by 75.27% of cell size (from an approximated original cell size 143 m x 133 m x 84 m)”.

L 227 & 229: replace ‘wells to correspond’ with ‘wells that correspond’ and ‘actual well’ should be deleted and just what is in brackets should be used. ‘known data’ respectively.

AR 227 & 229: The suggestion have been incorporated into the manuscript.

AC 227 & 229: Option 1 was to assign porosity and permeability values to the synthetic lithofacies wells that correspond to known facies-associations as indicated in **Table 4**. The synthetic wells with porosity and permeability data are placed in-between known data locations to guide porosity and permeability property distribution in the model.

L 230: Where the petrophysical properties guided by any trend data? Facies information? How were the values populated in the model?

AR 230: Yes the petrophysical properties were guided with trend map that where derived from the major orientation of the stratigraphic framework. In this instance, the orientation was in a NE-SW direction.

AC 230: For option 2 the best-fit forward stratigraphic model was populated with porosity, and permeability attributes using the stratigraphic orientation captured in the seismic data (i.e. NE-SW; 240^{o}) to control property distribution trends. Porosity and permeability were populated into the model by using the petrophysical modeling tool under property modeling process in Petrel^{TM}.

L 237: Please be more explicit as to what you mean by 80m and 120m? Is this TD of the well? MD? Or are they 80m and 120m spaced apart?

AR 237: 80 m and 120 m are the range of total depths (TD) of synthetic wells used in the study.

AC 237: Ten synthetic wells (SW), ranging between 80 m and a 120 m in total depth (TD) were positioned in the forward model to capture the vertical distribution of porosity-permeability at different sections of the stratigraphic model.

L 253: Figure 5 referenced need to have annotations which reflect the results discussed. For example, a line that indicates the MFS surface would be beneficial to readers.

AR 253: We agree totally with this comment, and have made some modifications to figure 5.

AC 253: Figure. 5 has been modified to indicate the maximum flooding surfaces (MFS) in the forward stratigraphic model. Its orientation has also been changed into landscape format (Figure 5).

L 258: A reference is required here with this statement. Please also remove ‘space’ and only just ‘accommodation’

AR 258: We have done the necessary correction on this line to include the references.

AC 258: This is consistent with real-world scenario where sediment supply matchup with accommodation generated as a result of the relative constant sea level rise within a period (e.g. Muto and Steel, 2000; Neal and Abreu, 2009).

L 262-270: This contains comments that are related to spelling mistakes.

AR 262-270: The suggestions have been taken on board, and the necessary corrections will be done.

AC 262-270: The impact of the stratigraphic simulation on porosity and permeability representation in the model was evaluated by comparing its outcomes to the original porosity and permeability models of the Volve dataset using two synthetic well prefixed VP1 and VP2. The synthetic well were sampled at a 5 m intervals vertically to estimate the distribution of porosity and permeability attributes along wells. Considering that the original porosity and permeability model (**Figure 11a**) have undergone phases of history matching to enable well planning and production strategies in the Volve field, it is reasonable to assume that porosity and permeability distribution in the Volve field petrophysical model will be geologically realistic and less uncertain.

L 272: I’m not sure what is mean by ‘modal distribution’? Do the authors mean multi-modal distribution? Normal distribution? I would suggest calculated the statistical model of the original Volve porosity model and then the models of the validation wells.

AR 272: According to the petrophysical evaluation report of the Volve field by Equinor, porosity in the reservoir is between 0.17-0.30. Vertical sampling in some selected models show more porosity values within this range (i.e. 0.17-0.30). This sentence is to illustrate how the FSM approach could generate outputs that are consistent with known data. I however, agree that more explained is required in the statement.

AC 272: The vertical distribution (**Figure 12)** of porosity in selected model realizations shows a large set of porosity values that range between 0.18 – 0.24. This output is consistent to porosity figures captured in the petrophysical evaluation of the Volve field (Equinor, 2016).

L 274-275: This statement needs to be reworded. Are the authors saying that stratigraphic inclination remains constant within the zones, or just other variogram parameters?

AR 274-275: We have made some changes to the statement as suggested by the reviewer.

AC 274-275: In view of the limitation in making variations within a simulation run in GPM^{TM}, the forward stratigraphic-based model was derived with an assumption that variogram parameters, stratigraphic inclination within zones are constant in each simulation run. In contrast, the original petrophysical model involve other measured attributes within the stratigraphic zone, hence the variations noted in Table 5b**.**

L277-281: This sentence is too long. Please break it into smaller, clearer sentences. Are the authors suggesting that the FSM is reasonable? Or are they suggesting that the permeability models should be conditioned to known subsurface data? This sentence should be a statement about the results of the model and what is suggested as uncertainties to consider when using these types of modelling methods.

AR 277-281: The sentence has been condensed to make it clearer to a reader.

AC 277-281: Typically, a petrophysical model like the Sleipner Øst and Volve field model will take into account other sources of data. For example, data from a special core analysis

(SCAL) will improve the reservoir petrophysics assessment. On the basis that the FSM approach did not involve these additional information from the formation, it is reasonable to suggest that the forward stratigraphic-based porosity and permeability models have been adequately conditioned to known subsurface data.

L 295-297: Sequence stratigraphy is a key component to lithofacies distribution characterisation, yes. This sentence should be condensed and reworded.

AR 295-297: Suggestion has been taken on board, and the appropriate modifications made.

AC 295-297: Indicated in previous studies, (e.g. Allen and Posamentier, 1993; Ghandour and Haredy, 2019) sequence stratigraphy is vital in the characterization of lithofacies in shallow marine settings. Aimed at replicating stratigraphic sequence formation in 3-D, the forward stratigraphic modeling approach in GPM^{TM} provide a good framework to analyse petrophysical property variations in a reservoir.

L 302-304: These lines refer to spelling mistakes.

AR 302-304: The corrections have been made as suggested in the comment.

AC 302-304: we concede that there is a possibility to overestimate and or underestimate porosity and permeability properties as observed in some sampled intervals of the validation wells. In view of this, it is our suggestion that forward stratigraphic simulation outputs should be applied as additional data to understand sediment distribution patterns, and associated vertical and horizontal petrophysical trends in the depositional environment than using its outputs as an absolute conditioning data in subsurface property modeling.

L 314-315: This sentence is too long. Please split into two statements for clarity.

AR 314-315: The sentence has been condensed as suggested by the reviewer.

AC 314-315: In reality, sediment deposition into a geological basin is also controlled by mechanical and geochemical processes that tend to modify a formations petrophysical attributes (Warrlich et al. 2010). Therefore, using different geological processes and initial conditions to generate depositional scenarios, will help to produce a best fits stratigraphic framework of the reservoir under study.

Reviewer 1

GC1: A big general concern I have regarding the manuscript is that all results hinge on the realistic prediction of the sediment deposition by the stratigraphic model GPM, but GPM is in this manuscript described and treated as a kind of "black box". As a reader, without knowledge of how GPM works internally, there is no way to check, know or estimate, how, why, or if the given input parameters will yield the results presented in the manuscript.

AR 1: We agree with the reviewer that the GPM software (at least the versions I used; 2017.1 to 2019.1 versions) acts as a "black box". However, the software tries to replicate a real world sedimentary process. For example, increasing sea level, and subsidence rate in GPM corresponds with an increase in accommodation. Similarly, high land-ward elevation, and erosion increases sediment supply into the basin.

AC 1: The focus of this study is to produce a depositional sequence that mimic the pattern in the seismic section in Figure 3b. Throughout the manuscript, further information will be provided in relevant sections to bring clarity on how the GPM software works.

GC 2: I am missing at least some basic equations or general explanations how the geological processes (Sediment Diffusion, Tectonics, Steady Flow, Unsteady Flow and Waves) act in GPM on the given input parameters. I, as someone not having worked with GPM before, have no idea and no possibility to understand how exactly the simulation results result from the little descriptions in the text and the values given in Table 2. What does GPM assume how the geological processes (Sediment Diffusion, Tectonics, Steady Flow, Unsteady Flow and Waves) act on the sediments? Another issue I have with the manuscript is that it is not made clear enough how the 20 scenarios of the stratigraphic simulations are connected with the 50 realizations. What are the realizations? How are they generated? For which scenario(s) are they applied? How and why are parameters of the scenarios and realizations chosen?

AR 2: This comment is very similar to the observations of reviewer 2. In addition, 20 scenarios are because of the uncertainty associated with the input parameters used to for the simulation. Different inputs were used to obtain a most representative stratigraphic framework. The 50 realizations are generated in the property modeling stage (porosity and permeability) in Petrel software, where synthetic wells data from a simulation (in this instance scenario 4) are used in a geostatistical algorithm (i.e. sequential Gaussian simulation) to generate a range of property representations. This will allow us to compare which outcome(s) match the original Volve field model from Equinor.

AC 2: We totally agree with the comment and the modification in the manuscript you follow the same style as the one presented in AC 1 under reviewer 2.

GC 3: In lines 86-87 the authors state "Simulations were constrained to twenty scenarios because the desired stratigraphic sequence and associated sediment patterns were achieved at the fourth simulation." I miss the discussion or details on how the authors determine what a desired stratigraphic sequence looks like and why they continued for 16 more scenarios, when Scenario 4 was already giving the desired stratigraphic sequence?

AR 3: A desired stratigraphic pattern in this contribution is one that exhibits similarity to the depositional sequence observed in the seismic section shown in Figure 3b. Additional 16 scenarios were generated as an attempt to enhance the results in scenario 4.

AC 3: Further explanations will be made in relevant sections to make the statement clearer to readers of this manuscript.

GC 4: A final general comment is that the authors claim that the presented approach reduces the uncertainty in the distribution of petrophysical properties such as porosity and permeability. In the conclusion, the authors discuss that even with their approach, uncertainty in the distribution of petrophysical properties will remain. They might increase the impact of their paper and prove their claim by comparing their resulting distribution with ones that are generated by other, more classical methods. Although I acknowledge that this might be a too big of a topic to include in this manuscript, I would find it good to at least mention the possible interest of such a comparison in the conclusion.

AR 4: In a related work, which compares the forward stratigraphic-based modeling approach to a classical technique (e.g. pixel based modeling) is being worked on. Notwithstanding that, this suggestion will be highlighted in the concluding part of this manuscript.

Line Comments

L 6-8: Something missing in this "Typically, reservoir modeling requires property-modifying coefficients in the form values to achieve a good match to known subsurface well data."

AR 6-8: The statement is not conclusive and not clear, so the appropriate changes will be made.

AC 6-8: Typically, reservoir modeling require continued property modification until an a appropriate match to known subsurface data is obtained.

L 25-27: Something missing in this "but the method tends to confine reservoir property models to known data and rarely realize geological realism to capture sedimentary that have led to reservoir formation" –> sedimentary processes??

AR 25-27: Again, we agree the statement is not conclusive. The corrections will be done as suggested.

AC 25-27: This statement will be modified to read "but the geostatistical-based method tends to confine reservoir property models to known data and rarely realize geological realism to capture sedimentary that have led to reservoir formation".

L 39: Something missing in this "The sedimentary system, Hugin formation makes up the main reservoir interval in the Volve field."

AR 39: We have taken the suggestion on board, and modification will be made to reflect the comment.

AC 39: The reservoir interval under study is located within the Hugin formation, which studies by Varadi et al. (1998); Kieft et al. (2011), have shown to be a complex depositional architecture of waves, tidal and fluvial processes; suggesting that a single depositional model will not be adequate to produce a realistic lithofacies distributions model.

L 69-70: Something missing in this "but the thickness have not been completely penetrated (Folkestad & Satur, 2006).

AR 69-70: The relevant changes will be made in the manuscript.

AC 69-70: This statement will be revised into “but the total thickness of code F lithofacies is not known (Folkestad & Satur, 2006).”

L 86-87: The desired stratigraphic sequence and associated sediment patterns were achieved" How did you determine this? What was the criterion for this decision? and then, why did you add another 16 scenarios, if the 4th was already showing "the desired stratigraphic sequence"? The scenarios are never discussed in detail and hidden away in Table 2 and only hinted at in some short statements e.g. lines 126-127 "To mitigate this uncertainty, 5 paleo topographic surfaces were generated stochastically" or lines 148-149 "The simulation parameters applied (Table 2) were generated randomly using the initial run.

AR 86-87: The main criteria for evaluating the realistic nature of a stratigraphic model was to compare it to the depositional sequence observed in the seismic section in Figure 3b, and/or interpreted through well correlation.

AC 86-87: The changes made in these lines was to include the Author’s response (AR) above.

L 99-114: As said in the general comments, I miss some detail on how the mentioned processes are implemented in GPM, how are they parameterized etc...

AR 99-114: This is related to GC2, so the explanation provided will suffice for this comment.

AC 99-114: The changes that have been made include details on the parameterization of the geological processes used in simulation.

L 128: TPr is not defined. I assume it is the " paleo topographic surface" or something similar from the context.

AR 128: Yes, TPr is the paleo-topographic surface of the model area.

AC 128: To mitigate this uncertainty, 5 paleo topographic surfaces (TPr) were generated by adding or subtracting elevations from the inferred paleo topographic surface or base topography (see Figure 4g).

L 133-136: The sediment entry point for this task was placed in the north-eastern section of the hypothetical paleo-topography. Since the exact sediment entry point is uncertain, multiple entry points were placed at 4 m radius around the primary location in (Figure 3c), in order to capture possible sediment source locations." Compared to the scale shown in Figure 3c or the area given in line 221 (~18km2), a 4m radius seems to me just as the same location, as the modelled area seems kilometres wide. Or do you mean 4km? Could an sediment entry point actually be as narrow as 4m within such a relatively flat looking domain as shown in Figure 3c.

AR 133-136: The distance should be 4 km and not 4m as stated in the manuscript. The correction will be made in the manuscript.

AC 133-136: Based on regional well correlations in previous studies (e.g. Kieft et al. 2011), and seismic interpretation of the basin structure, the sediment entry point was placed in the north-eastern section of the hypothetical paleo-topography. Since the exact sediment entry point is not known, multiple entry points were placed at 4 km radius around the primary location in (Figure 3c), in order to capture possible sediment source locations. The source position is characterised by positive integers (i.e. values greater than zero) to enable fluid flow to other parts of the simulation surface.

L 139-140: What was the assumed sea level after 20000 years? Only the average sea levels are given later in Table 2

AR 139-140: The sea level curve used in the simulation followed the Haq global sea level curve generator as well as the Exxon global sea level curve generator formats. The sea level for year 20,000 was assumed to be 45 m, and decreased to 15 m by year zero. The sea level was not kept constant as it is a curve that covered a period of geological period (see figure 1). Averages were used in the manuscript to provide an insight into the mean sea level that was in the simulation scenarios.

AC 139-140: To attain stability in the simulator, we assumed a sea level that range between 15 m to 45 m; averaging 30 m for short simulation runs, e.g. 5000 to 20000 years. The sea level was varied with increasing duration of the simulation (illustrated in Table 2). The peak sea-level in the simulation represents the maximum flooding surface (Figure 5d), and therefore the inferred sequence boundary in the geological process model.

L 148-149: and following: "The simulation parameters applied (Table 2) were generated randomly" on what basis were they created? Was the simulation always constant with no changes? I did not find any boundary conditions, so how much sediment enters the study area? Is this constant over time? The following lines e.g. "A sudden change in subsidence rate tends" suggest that the (boundary) conditions changed over time.

AR 148-149: With scenario 1 (Figure 6a) beginning to show resemblance to the target output (i.e. the depositional pattern observed in seismic section; Figure 3b), we generated input figures that were higher and lesser than those used in generating scenario 1. Example, based on a diffusion coefficient of 8 m2/a that was used in scenario 1, diffusion coefficients +/- 5 of 8 were generated with the aim to improve the development in scenario 1. Since the initial conditions (boundary conditions) at the time of deposition are unknown, an attempt was made to apply input parameters that will produce a comparable stratigraphic pattern to what is observed in the seismic section (Figure 3b). Aside the initial topography that was kept constant in a simulation run, other input parameters such as diffusion, wave event, steady/unsteady flow, tectonics use curve functions to provide variations within the simulated period.

AC 148-149: Modifications made in the manuscript is the same as the author's response (AR) above.

L 157: "Shifting the source point to the mid-section of the topography" to where exactly? can you show that in Figure 3? Isn't the sediment entry point shown in figure 3 already somewhat in the mid-section, at least when looking at figure 3? And previously, you wrote that you only look into changes within a 4m radius of the sediment entry point, so I do not understand how it can have such a big influence, see lines 133-136.

AR 157: The "mid-point" used in the manuscript is the middle section of the entire topography (i.e. basin-ward, close to the basin slope; see modified image below; labelled Figure 2). The point was made to show that the location of the sediment source in the simulation will have a huge impact on the resultant stratigraphic architecture.

AC 157: Shifting the source point to the mid-section of the topography (i.e. the mid-point of the topography in a basin-ward direction) resulted in the accumulation of distal elements that are identical to turbidite lobe systems.

L 176-178: "shoreface lithofacies units were characterized using medium-to-coarse grained sediments to that are proximal sediment source, whiles mudstone units are constrained to the distal parts of the stratigraphic model, where fine grained sediments accumulate at the end of the simulation." –> coarse grained sediments that are proximal to the sediment source? "at the end of the simulation." Do you mean at the distal end of the simulation domain or towards the end of the simulated time? Time or space is not clear from the wording.

AR 176-178: Here, we mean the distal end of the simulation domain at the end of each run in the GPM simulator. The appropriate modification will be done in the manuscript to make the point clearer.

AC 176-178: For example, shoreface lithofacies units were characterized using medium-to-coarse grained sediments, which accumulate at proximal distance to the sediment source. In contrast, mudstone units were restricted to fine grained sediments that accumulate at distal section of the simulation domain.

L 179-180: "attributes, which is" –>"attributes, which are"

AR 179-180: These are Wireline-log attributes such as gamma ray, neutron porosity, sonic, and density logs outlined in Table 1 in the supplement.

AC 179-180: Using published studies by Kieft et al., (2011), porosity and permeability variations in the stratigraphic model were estimated from wireline-log attributes such as gamma ray, neutron, sonic, and density logs outlined in Table 1.

L 186: x not defined.

AR 186: “x” as used here is the multiplication symbol.

AC 186: $Ø_{er} = Ø_D + \alpha \,.\, (NPHI - Ø_D) + \beta;$ where $Ø_{er}$ is the estimated porosity range, $Ø_D$ is density porosity, α and β are regression constants; ranging between -0.02 – 0.01 and 0.28 – 0.4 respectively, *NPHI* is neutron porosity.

Line 197-218: inconsistent numbering

AR 197-218: (i) and (ii) where used to show that the pillar gridding process, horizon, zoning and layering processes are all part of the structural modeling process. The numbering will be modified into a 1 to 4.

AC 197-218:

1. Structure modelling: identified faults within the study area are modelled together with interpreted surfaces from seismic and well data to generate the main structural framework, within which the entire property model will be built. The procedures involve modification of fault pillars and connecting fault bodies to one another to attain the kind of fault framework interpreted from seismic and core data.

(2) Pillar gridding: a “grid skeleton” that is made up of a top, middle and base architectures. Typically, pillars join corresponding corners of every grid cell of the adjacent grid to form the foundation for each cell within the model. The prominent orientation of faults (i.e. I-direction) within the model area generally trends in a N-S and NE-SW direction, so the “I-direction” was set to the NNE-SSW direction to capture the structural description.

L 223: "and compressed by 75.27% of cell size" the verb is missing –> "and is compressed by 75.27% of the cell size"?

AR 223: The sentence shall be corrected.

AC 223: The original petrophysical model has a grid dimension of 108 m x 100 m x 63 m, and is compressed by 75.27% of cell size (from an approximated cell size 143 m x 133 m x 84 m). To achieve a comparable model resolution as the original porosity and permeability model, the forward stratigraphic output with initial resolution of 90 m x 78 m x 45 m was upscaled to a cell size of 107 m x 99 m x 63 m.

L 237: What are the length measures? Well lengths, distances, ...?

AR 237: This statement will be corrected to make its meaning clearer.

AC 237: Ten synthetic wells (SW), ranging between 80 m and a 120 m in total depth (TD) were positioned in the forward model to capture the vertical distribution of porosity-permeability at different sections of the stratigraphic model. The average distance between these wells as shown in Figure 9c is about 0.9 km apart, with a maximum and minimum of 1.3 km and 0.65 km respectively.

L 243: "populated" –> populate + How can wells be upscaled to the original structural model? Upscaling usually refers to representing something at a larger scale, not to extrapolate from lower dimensional objects (wells are practically 1D) to higher dimensions (the 3D structural model). I am confused here, but my guess is that the 1D to 3D extrapolation is meant here with upscaling. Please clarify. After rethinking, I do not even understand the purpose of the 10 synthetic wells, why do you use them? As I understand it, you should have from the previous steps already the full 3D structural stratigraphic information, so why throw away all that, keep only 10 locations and then reconstruct again everything? Couldn’t you just directly populate the stratigraphic 3D domain?

AR 243: The synthetic wells derived from the stratigraphic model is to provide an additional well data for use in a traditional modeling workflow as was the case in the building of original Volve model. Using the same structural model was to attain a comparable framework for evaluating the modeling outputs. Upscaling the synthetic well data is a standard procedure to “transform” the data from 1-D into a 3-D framework to build the property model.

AC 243: The variogram model (**Figure 10**), of dominant lithofacies units in the formation served as a guide in the estimation of variogram parameters from the forward model.

L 249-250: "Out of fifty model realizations, six realizations that showed some similarity to the original petrophysical model are presented" How did you generate the 50 realizations exactly? How did you quantify the similarity? For which scenario did you do the 50 realizations? All 20? Only scenario 4? Could you at some point specify this, so for what scenarios did you do the model realizations? And I assume you mean the "Porosity and Permeability model", can you confirm?

AR 249-250: The selection of six realizations was based on visual and statistical comparison of zones in the original Volve field model, and the stratigraphic-based porosity/permeability models. The statistical approach involved the comparison of summary statistics from the original Volve model, and the model realizations generated in the Petrel software. The visual comparison on the other hand looks at how geological realistic the output is, and if it conforms with our conceptual idea of the Volve field model.

AC 249-250: Out of fifty model realizations, six realizations that showed some similarity to the original petrophysical model are presented (**Figure 11**). This was achieve through visual and statistical comparison of zones in the original Volve field model, and the stratigraphic-based porosity/permeability models. The statistical approach involved the comparison of summary statistics from the original Volve model, and the model realizations generated in the Petrel software. The visual comparison on the other hand looks at how geological realistic the output is, and if it conforms with our conceptual idea of the Volve field model.

L 277-278: Did you do any of that what you write is "typically" done?

AR 277-278: No we didn’t do that. The explanation to this is that a property model that has been used for production purposes would have gone through different phases of history matching, hence its adoption as a reasonable base model. The aim is to ascertain the practicability of using the forward stratigraphic modeling technique to predict property variation in a hydrocarbon reservoir.

AC 277-278: Typically, a petrophysical model like the Sleipner Øst and Volve field model will take into account other sources of data. For example, data from a special core analysis (SCAL) will improve the reservoir petrophysics assessment. Considering that the FSM approach did not involve these additional information from the formation, it is reasonable to suggest that the forward stratigraphic-based porosity and permeability models have been adequately conditioned to known subsurface data.

L 291: "multiple simulation scenarios" The 20 (GPM?) simulation scenarios defined in Table 2? How do they link to the poro-perm model realizations? See comment on lines 249-250.

AR 291: The 20 simulation scenarios generated are related to the depositional models (stratigraphic models). Out of the 20 scenarios, scenario 4 was adopted and populated with porosity and permeability attributes. So out of the 20 stratigraphic modeling scenarios only scenario 4 has a direct relationship to the 50 realizations produced in the property model.

AC 291: Since the initial conditions of this basin is uncertain, multiple simulation scenarios were carried out to account for the range of bathymetries that may have influenced sediment transportation to form the present day Hugin formation. The simulation produced well defined clinoforms and sequence boundaries that depict the pattern observed in the seismic data. Clinoforms in this context, are sloping depositional surfaces in a stratigraphic architecture (Patruno & Hansen, 2018).

L 298: "A porosity-permeability model that match the original petrophysical model was produced" –> A porosity-permeability model matching the original petrophysical model was produced.

AR 298: We agree to the suggestion from the reviewer, and will make corrections to that effect.

AC 298: A porosity-permeability model matching the original petrophysical model was produced using synthetic porosity and permeability logs from the forward stratigraphic model as input datasets in the sequential Gaussian simulation algorithm.

L 340: “will improve property prediction away from data" Away from data sounds weird to me, what do you mean with that exactly? Extrapolation away from points (wells) where there is data (well logs)?

AR 340: More conditioning data (well data) will enhances the chance of attaining realistic distributions in the model area. So with the forward stratigraphic-based property model providing a realistic stratigraphic framework, synthetic wells can be obtained to control property modeling of the reservoir. In addition the term “data” used in the manuscript refers to well logs.

AC 340: The good match obtained from validation wells in the original and stratigraphic-based petrophysical model, leads us to the suggestion that an integration of variogram parameters from well data and forward stratigraphic simulation outputs will improve property prediction in inter-well zones. This suggestion is supported by the idea that more conditioning data (well data) will increase the chance of producing realistic property distribution in the model area.

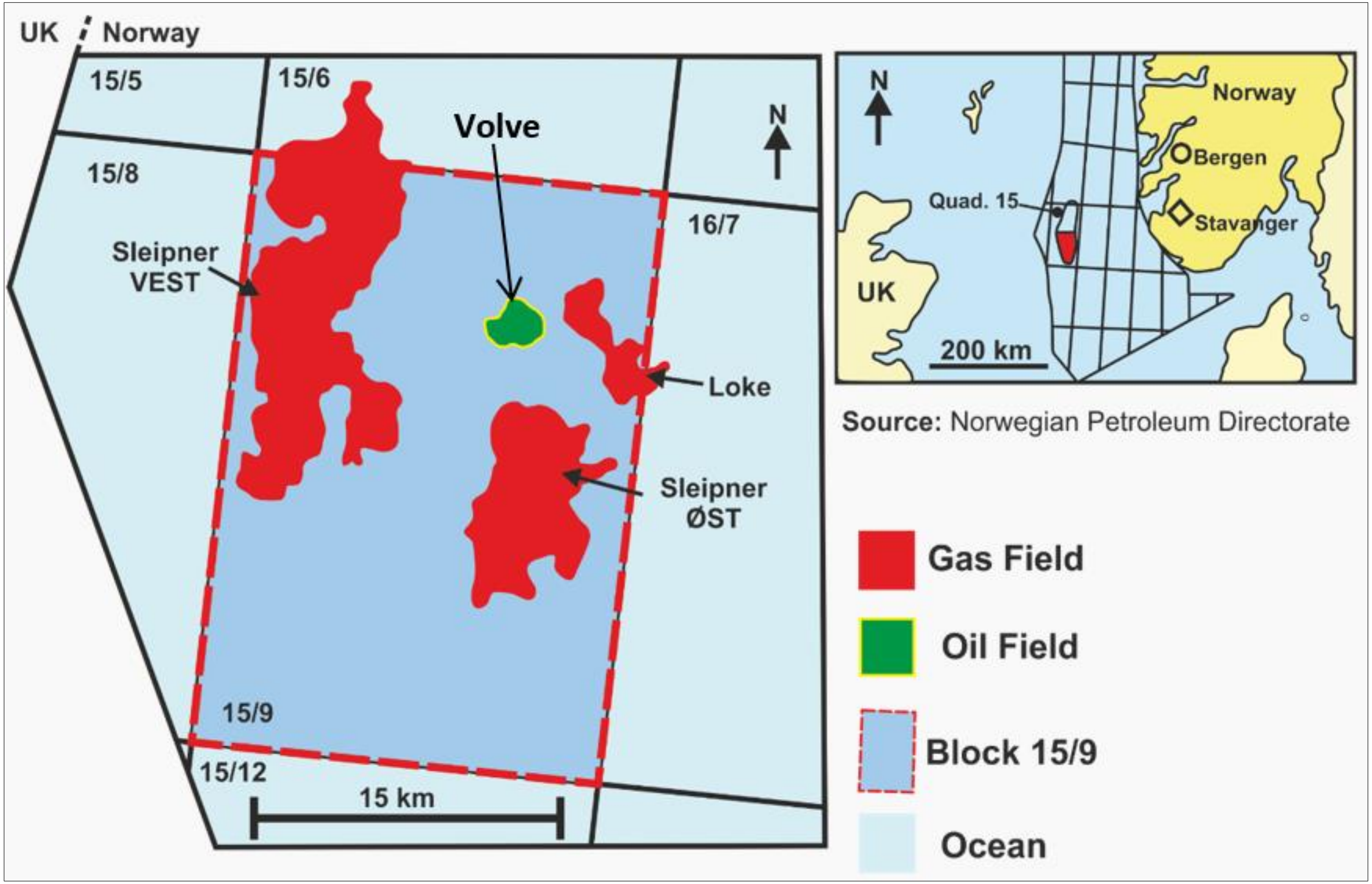
Line 355-358: How can you guarantee that the artificial neural network approach will not have similar biases, which only are better hidden as they are less understood? How do you provide training data without cognitive or sampling biases to ensure that the artificial neural network will not train to reproduce those biases?

AR 355-358: In our view, the calculator approach used in estimating the lithofacies proportions in the stratigraphic model were constrained to the extent to which we assume such distributions should go. Meanwhile, with an unsupervised machine learning via neural network, we can attain many outcomes that are not restricted by our cognitive biases. The neural network can be defined with varying components (e.g. weights) to attain different outcomes, from which a best fit vertical profile that is comparable to real well log can be adopted.

List of Figures

Generally, comments on figures had to do with its clarity and caption. The appropriate corrections have been done, such that the orientation of some of the figures have been changed into landscape to make them clearer.

Also, Figure 12 have been divided into two (i.e. Figure 12a, and Figure 12b), in order to make it clearer and readable.



Source: Norwegian Petroleum Directorate

Figure 1

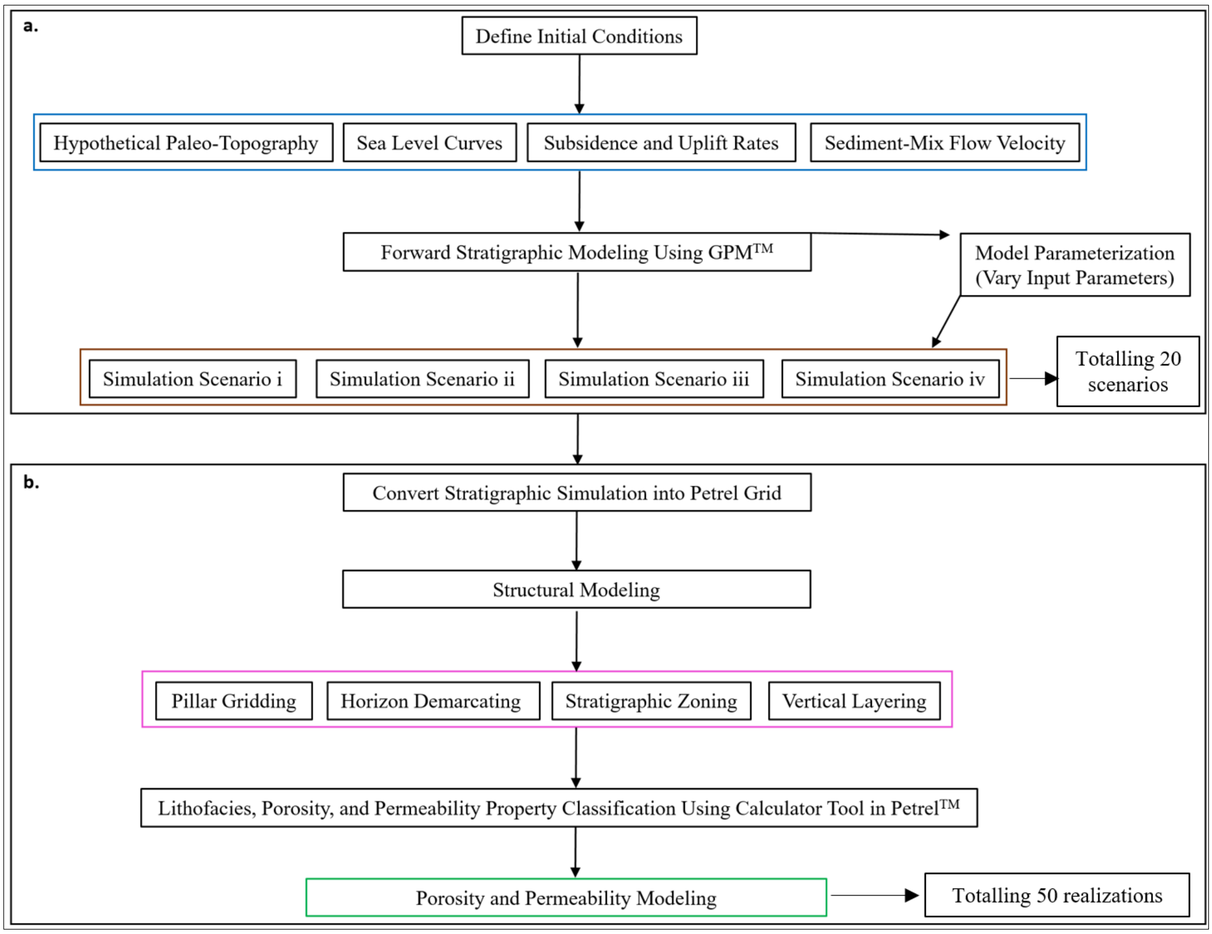
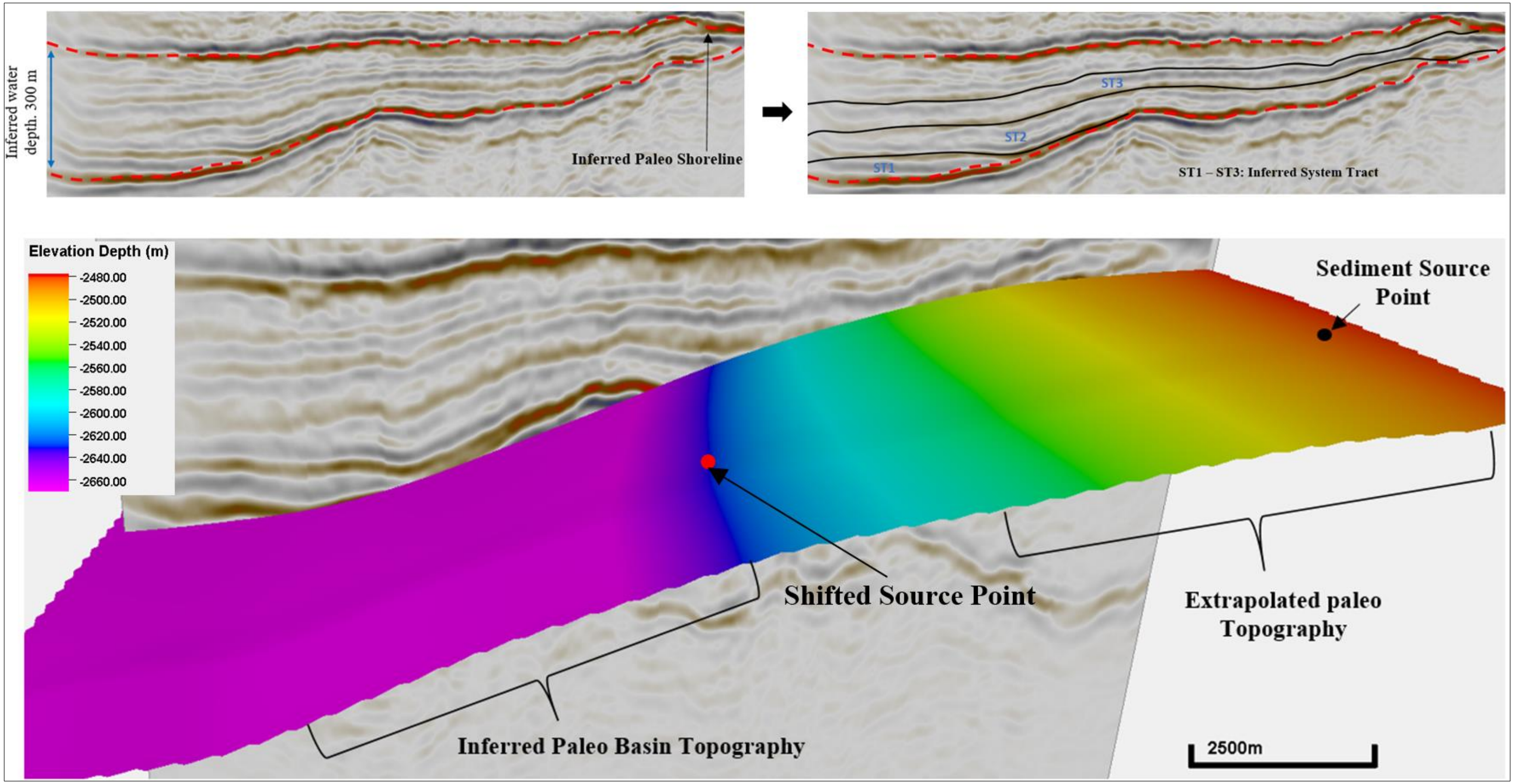

a.
Define Initial Conditions
Hypothetical Paleo-Topography
Sea Level Curves
Subsidence and Uplift Rates
Sediment-Mix Flow Velocity
Forward Stratigraphic Modeling Using GPM™
Model Parameterization (Vary Input Parameters)
Simulation Scenario i
Simulation Scenario ii
Simulation Scenario iii
Simulation Scenario iv
Totalling 20 scenarios
b.
Convert Stratigraphic Simulation into Petrel Grid
Structural Modeling
Pillar Gridding
Horizon Demarcating
Stratigraphic Zoning
Vertical Layering
Lithofacies, Porosity, and Permeability Property Classification Using Calculator Tool in Petrel™
Porosity and Permeability Modeling
Totalling 50 realizations

Figure 2



Inferred water depth. 300 m
Inferred Paleo Shoreline
ST3
ST2
ST1
ST1 – ST3: Inferred System Tract
Elevation Depth (m)
-2480.00
-2500.00
-2520.00
-2540.00
-2560.00
-2580.00
-2600.00
-2620.00
-2640.00
-2660.00
Sediment Source Point
Shifted Source Point
Extrapolated paleo Topography
Inferred Paleo Basin Topography
2500m

Figure 3

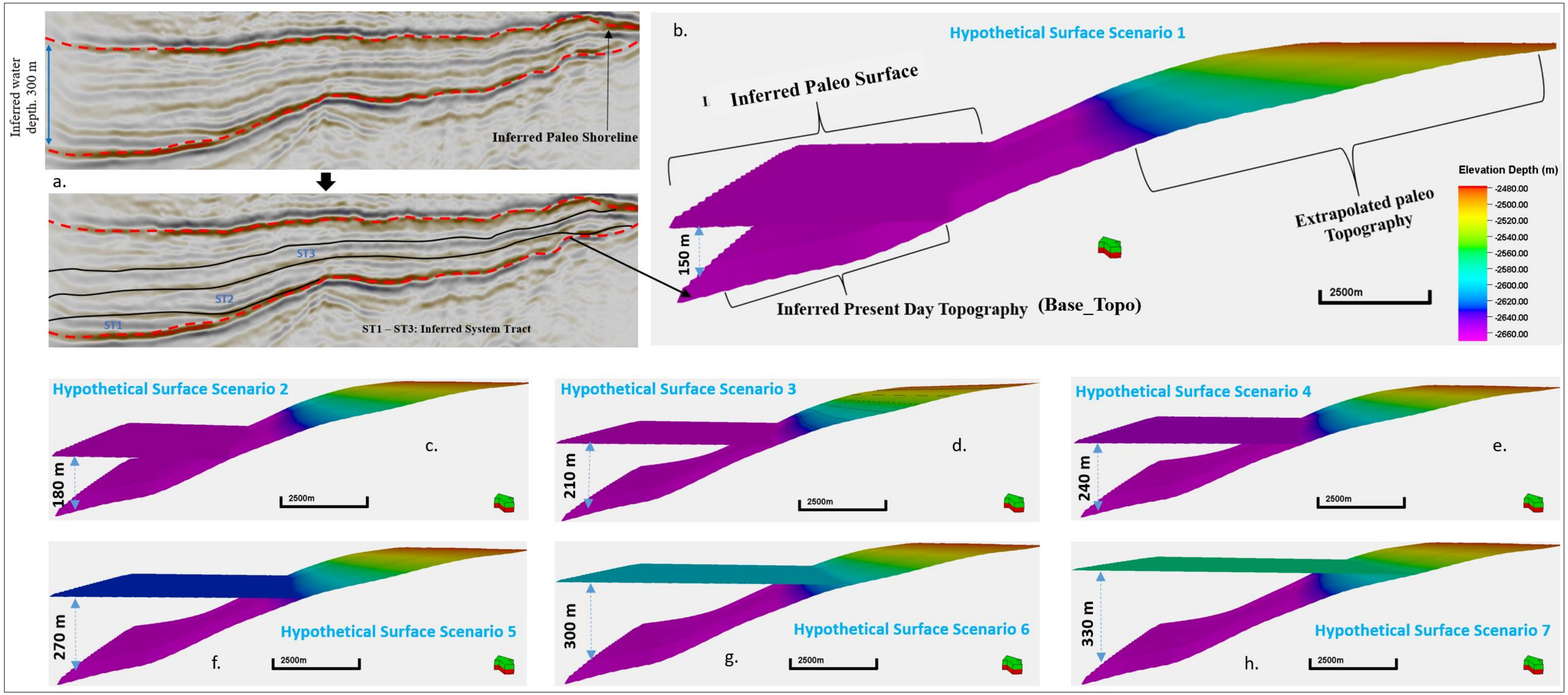

Inferred water depth. 300 m
Inferred Paleo Shoreline
a.
ST3
ST2
ST1
ST1 – ST3: Inferred System Tract
b.
Hypothetical Surface Scenario 1
Inferred Paleo Surface
150 m
Inferred Present Day Topography (Base_Topo)
Extrapolated paleo Topography
2500m
Elevation Depth (m)
-2480.00
-2500.00
-2520.00
-2540.00
-2560.00
-2580.00
-2600.00
-2620.00
-2640.00
-2660.00
Hypothetical Surface Scenario 2
c.
180 m
2500m
Hypothetical Surface Scenario 3
d.
210 m
2500m
Hypothetical Surface Scenario 4
e.
240 m
2500m
Hypothetical Surface Scenario 5
270 m
f.
2500m
Hypothetical Surface Scenario 6
300 m
g.
2500m
Hypothetical Surface Scenario 7
330 m
h.
2500m

Figure 4

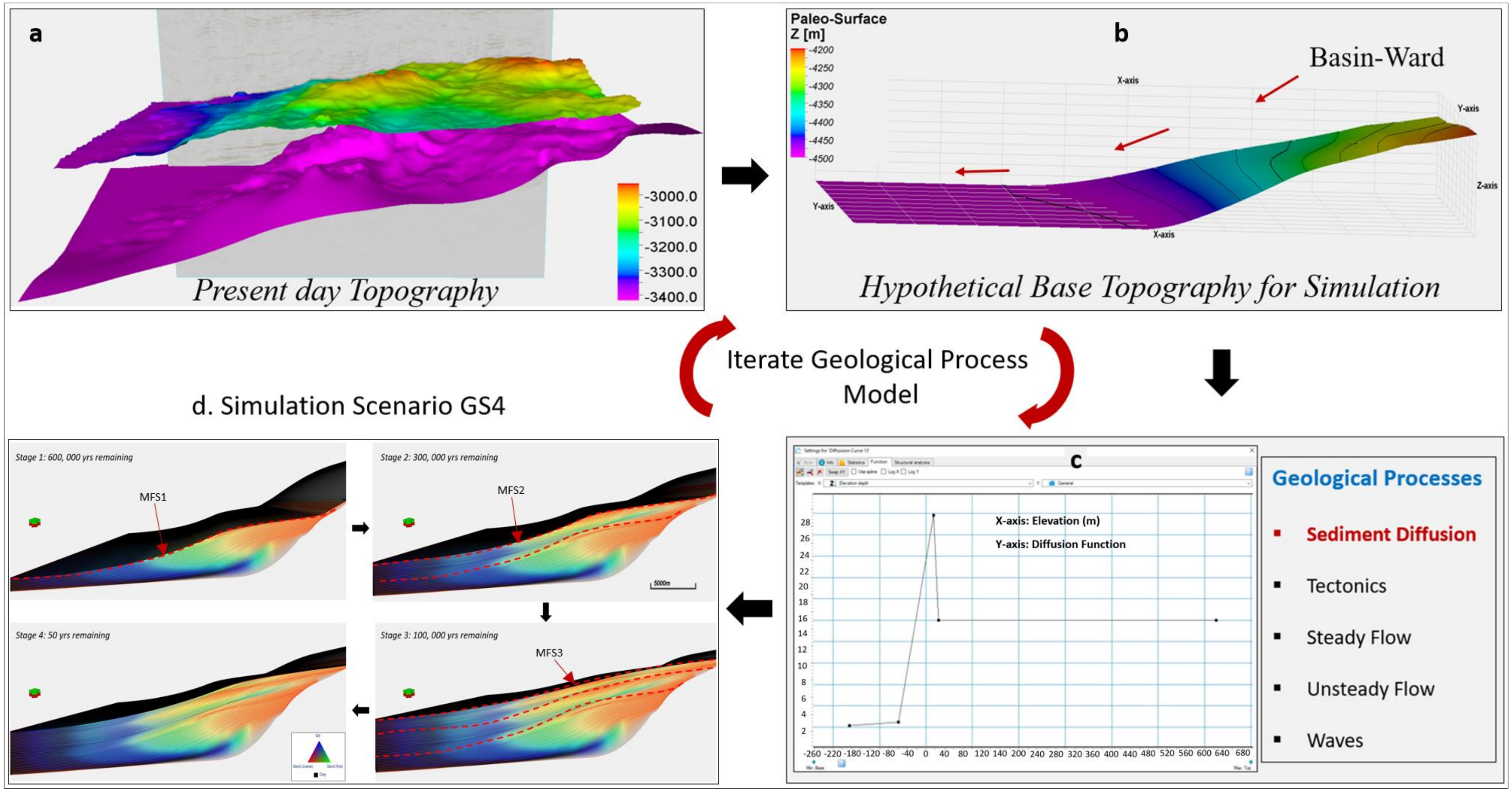

a
-3000.0
-3100.0
-3200.0
-3300.0
-3400.0
Present day Topography
b
Paleo-Surface
Z [m]
-4200
-4250
-4300
-4350
-4400
-4450
-4500
Basin-Ward
X-axis
Y-axis
Z-axis
Hypothetical Base Topography for Simulation
Iterate Geological Process Model
c
X-axis: Elevation (m)
Y-axis: Diffusion Function
28
26
24
22
20
18
16
14
12
10
8
6
4
2
-260 -220 -180 -120 -80 -40 0 40 80 120 140 200 240 280 320 360 400 440 480 520 560 600 640 680
Geological Processes
▪ Sediment Diffusion
▪ Tectonics
▪ Steady Flow
▪ Unsteady Flow
▪ Waves
d. Simulation Scenario GS4
Stage 1: 600, 000 yrs remaining
MFS1
Stage 2: 300, 000 yrs remaining
MFS2
5000m
Stage 3: 100, 000 yrs remaining
MFS3
Stage 4: 50 yrs remaining
Silt
Sand (coarse)
Sand (fine)
Clay

Figure 5

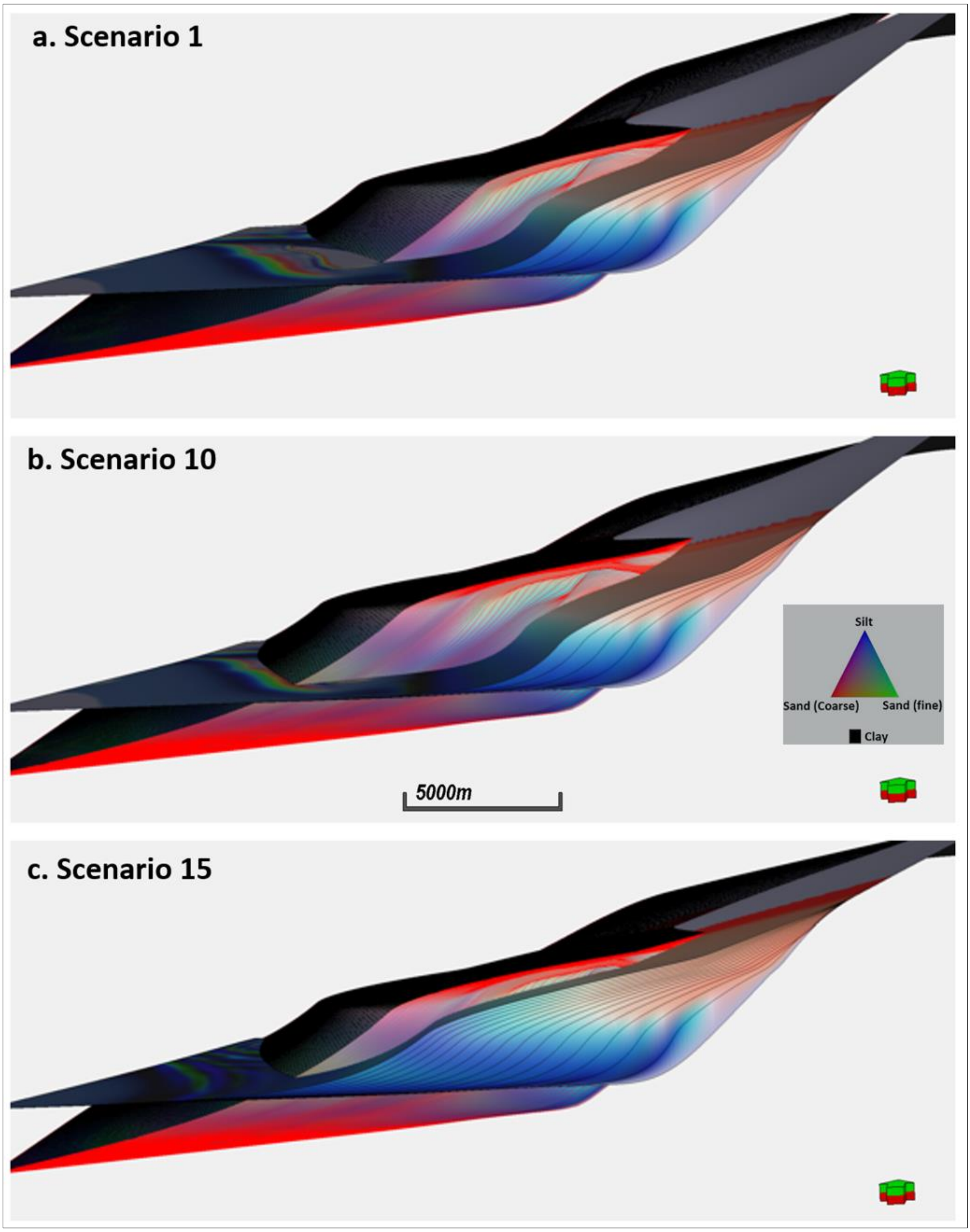

a. Scenario 1
b. Scenario 10
Silt
Sand (Coarse)
Sand (fine)
Clay
5000m
c. Scenario 15

Figure 6

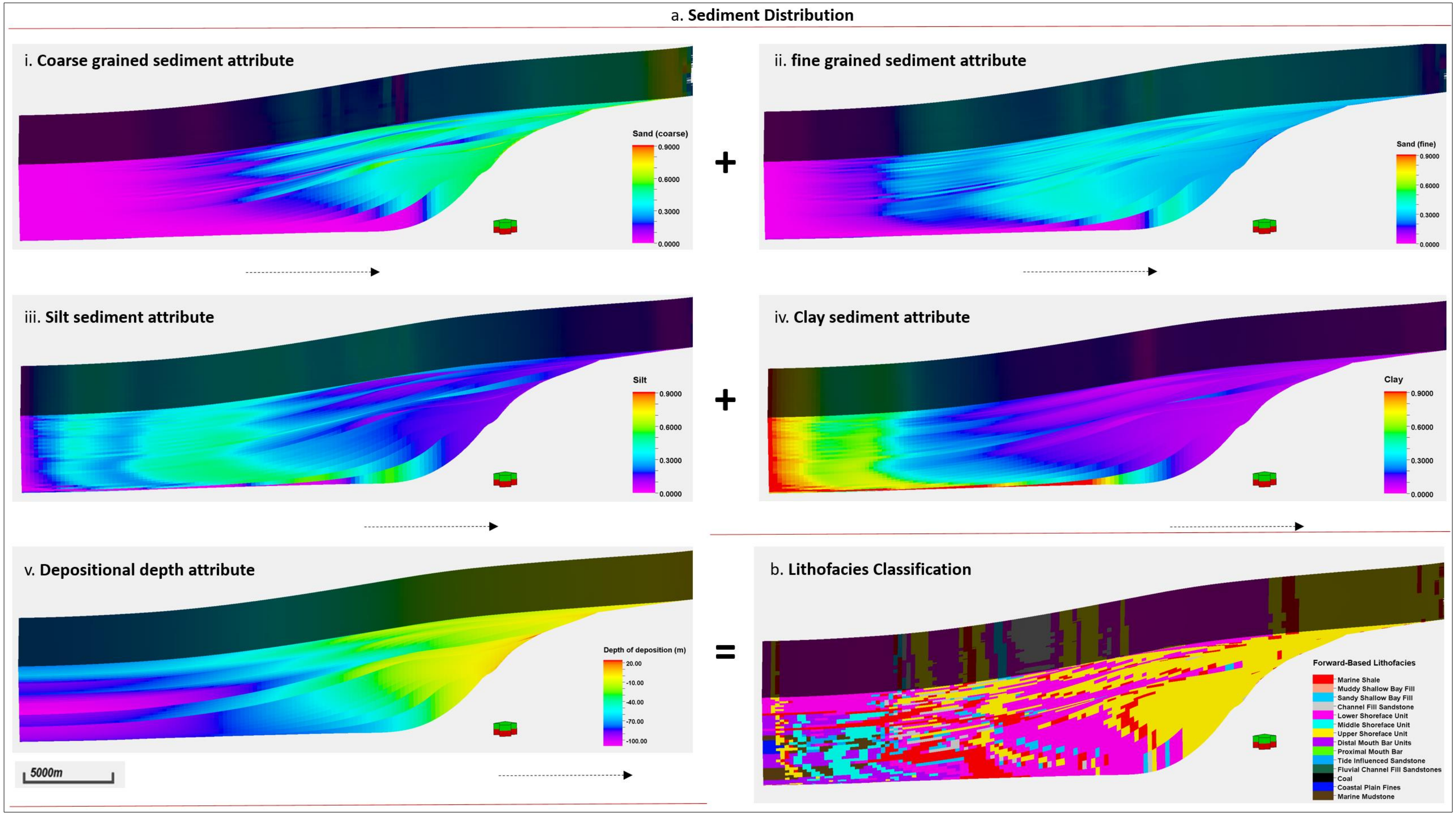

a. Sediment Distribution
i. Coarse grained sediment attribute
Sand (coarse)
0.9000
0.6000
0.3000
0.0000
+
ii. fine grained sediment attribute
Sand (fine)
0.9000
0.6000
0.3000
0.0000
iii. Silt sediment attribute
Silt
0.9000
0.6000
0.3000
0.0000
+
iv. Clay sediment attribute
Clay
0.9000
0.6000
0.3000
0.0000
v. Depositional depth attribute
Depth of deposition (m)
20.00
-10.00
-40.00
-70.00
-100.00
=
5000m
b. Lithofacies Classification
Forward-Based Lithofacies
Marine Shale
Muddy Shallow Bay Fill
Sandy Shallow Bay Fill
Channel Fill Sandstone
Lower Shoreface Unit
Middle Shoreface Unit
Upper Shoreface Unit
Distal Mouth Bar Units
Proximal Mouth Bar
Tide Influenced Sandstone
Fluvial Channel Fill Sandstones
Coal
Coastal Plain Fines
Marine Mudstone

Figure 7

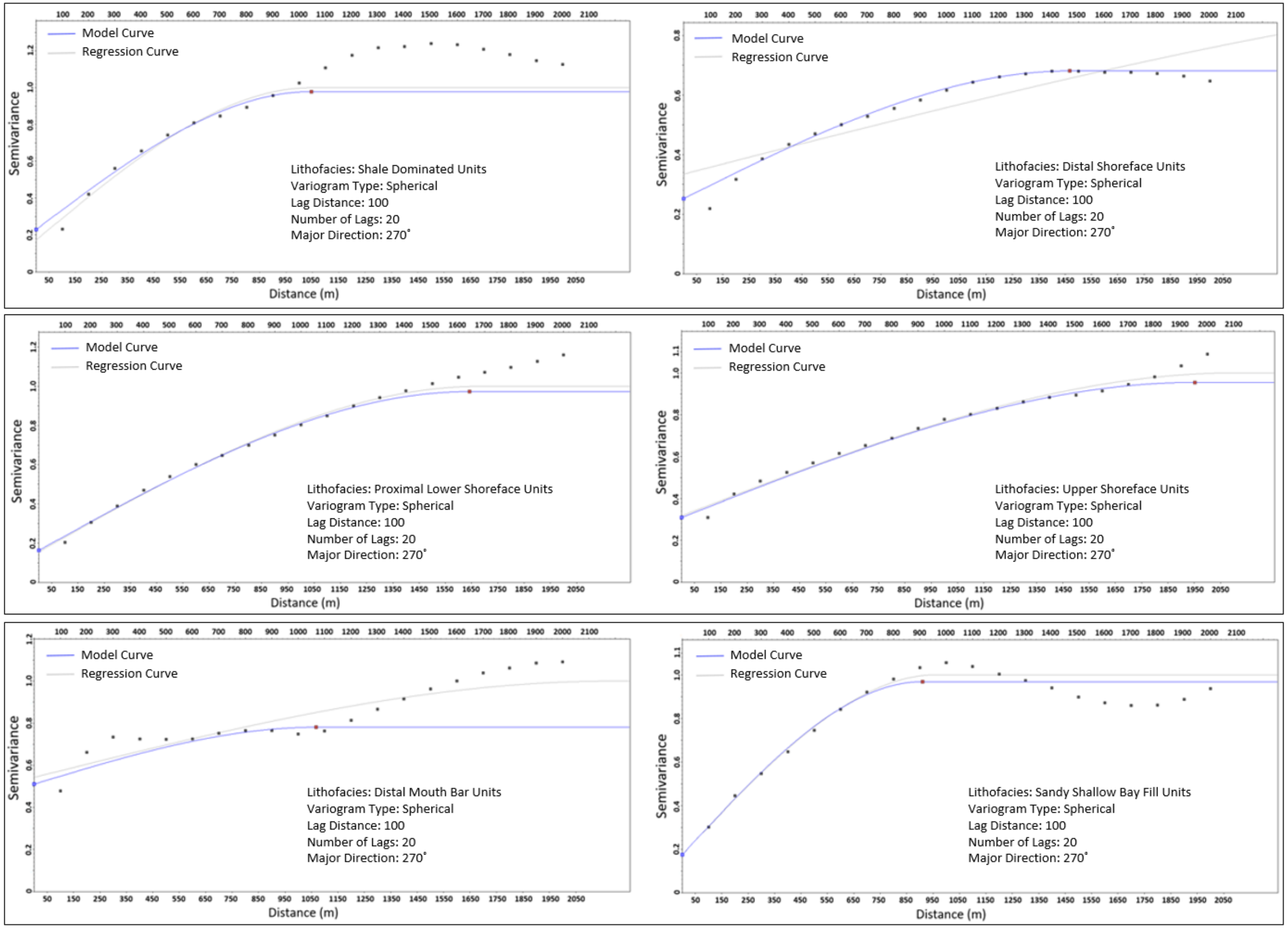

Model Curve
Regression Curve
Semivariance
Distance (m)
Lithofacies: Shale Dominated Units
Variogram Type: Spherical
Lag Distance: 100
Number of Lags: 20
Major Direction: 270˚
Model Curve
Regression Curve
Semivariance
Distance (m)
Lithofacies: Distal Shoreface Units
Variogram Type: Spherical
Lag Distance: 100
Number of Lags: 20
Major Direction: 270˚
Model Curve
Regression Curve
Semivariance
Distance (m)
Lithofacies: Proximal Lower Shoreface Units
Variogram Type: Spherical
Lag Distance: 100
Number of Lags: 20
Major Direction: 270˚
Model Curve
Regression Curve
Semivariance
Distance (m)
Lithofacies: Upper Shoreface Units
Variogram Type: Spherical
Lag Distance: 100
Number of Lags: 20
Major Direction: 270˚
Model Curve
Regression Curve
Semivariance
Distance (m)
Lithofacies: Distal Mouth Bar Units
Variogram Type: Spherical
Lag Distance: 100
Number of Lags: 20
Major Direction: 270˚
Model Curve
Regression Curve
Semivariance
Distance (m)
Lithofacies: Sandy Shallow Bay Fill Units
Variogram Type: Spherical
Lag Distance: 100
Number of Lags: 20
Major Direction: 270˚

Figure 10

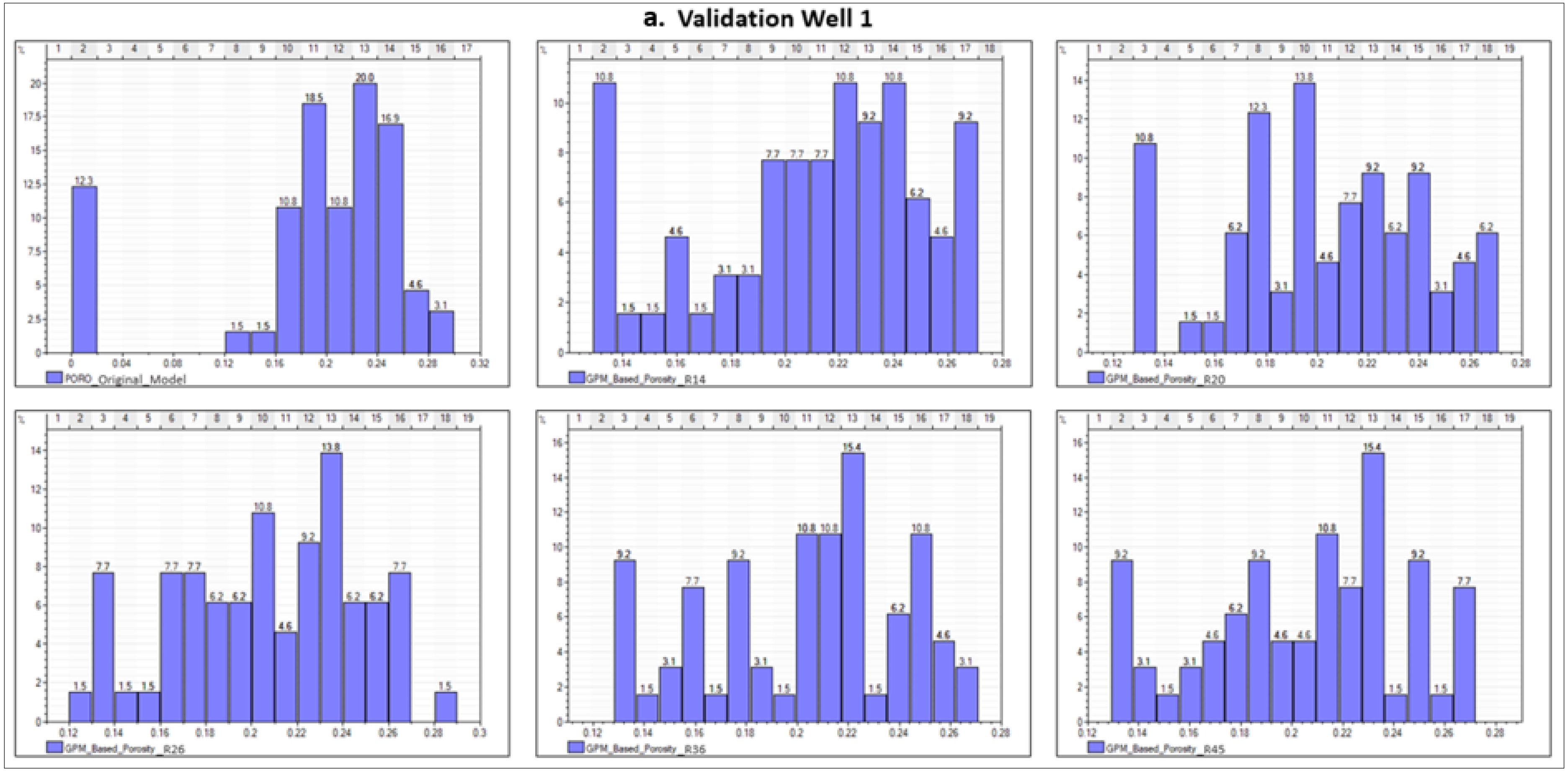

a. Validation Well 1
PORO_Original_Model
12.3
1.5
1.5
10.8
18.5
10.8
20.0
16.9
4.6
3.1
GPM_Based_Porosity_R14
10.8
1.5
1.5
4.6
1.5
3.1
3.1
7.7
7.7
7.7
10.8
9.2
10.8
6.2
4.6
9.2
GPM_Based_Porosity_R20
10.8
1.5
1.5
6.2
12.3
3.1
13.8
4.6
7.7
9.2
6.2
9.2
3.1
4.6
6.2
GPM_Based_Porosity_R26
1.5
7.7
1.5
1.5
7.7
7.7
6.2
6.2
10.8
4.6
9.2
13.8
6.2
6.2
7.7
1.5
GPM_Based_Porosity_R36
9.2
1.5
3.1
7.7
1.5
9.2
3.1
1.5
10.8
10.8
15.4
1.5
6.2
10.8
4.6
3.1
GPM_Based_Porosity_R45
9.2
3.1
1.5
3.1
4.6
6.2
9.2
4.6
4.6
10.8
7.7
15.4
1.5
9.2
1.5
7.7

Figure 12a

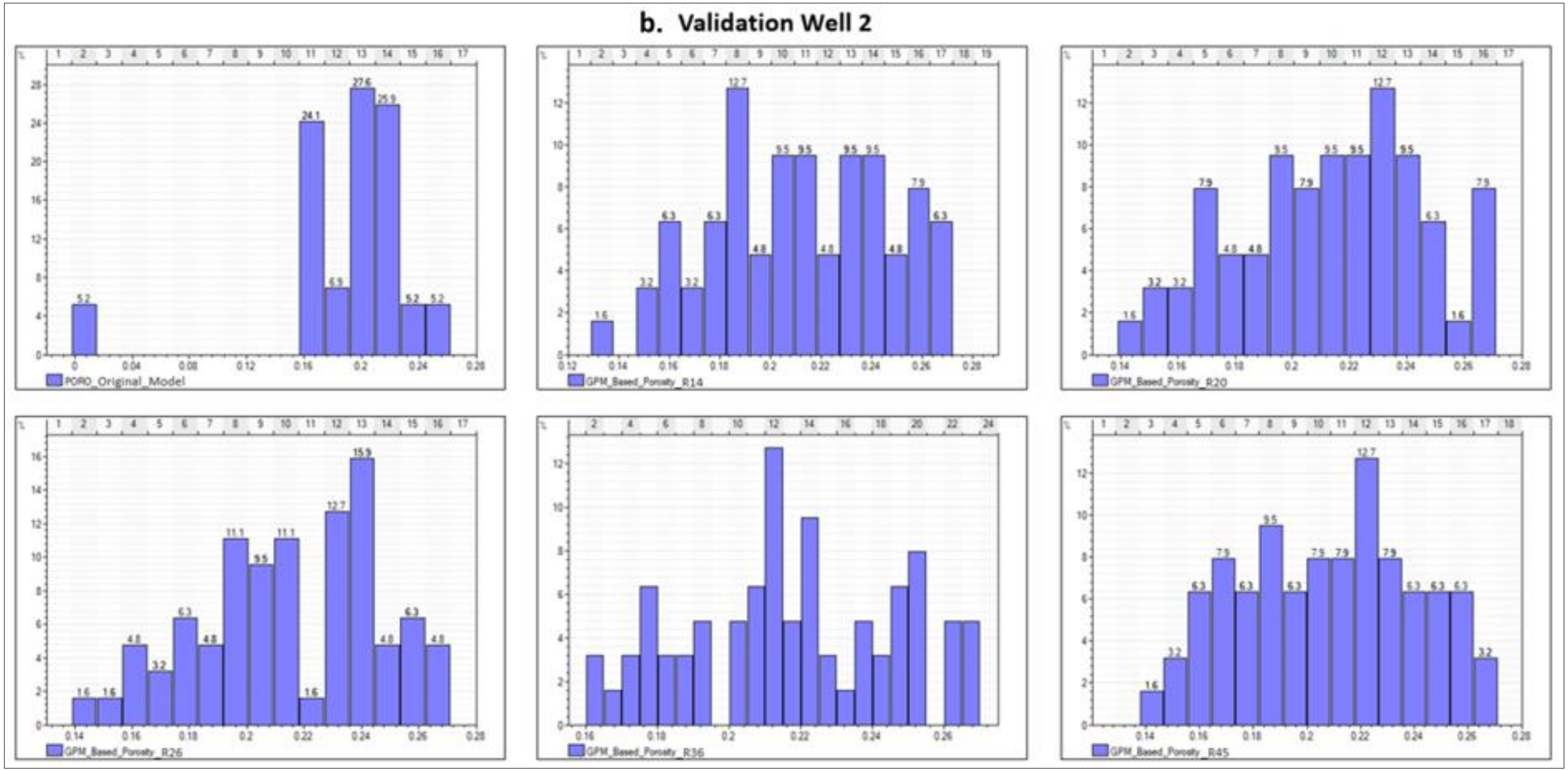
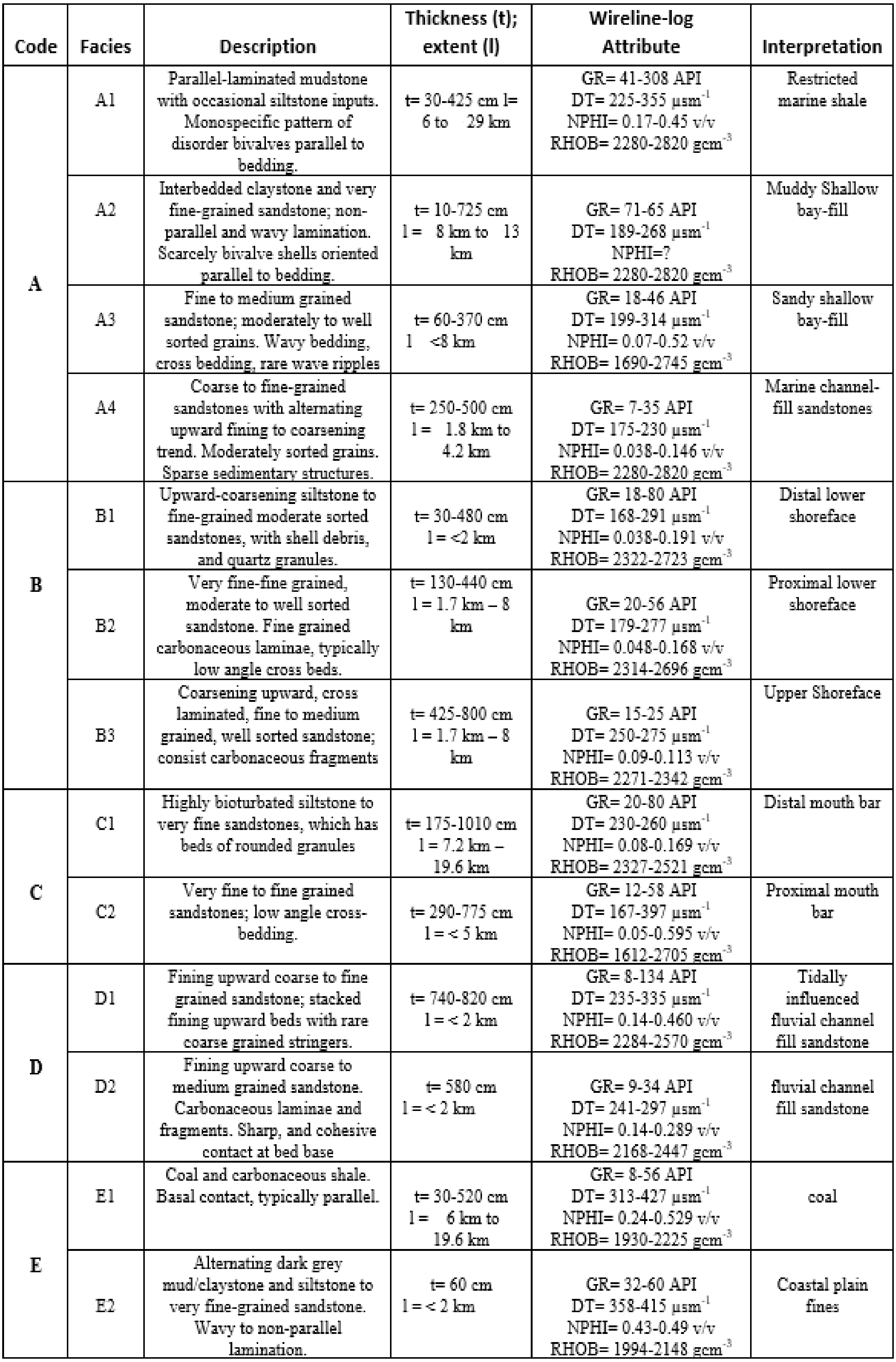

b. Validation Well 2

Figure 12b

Table 1



Code	Facies	Description	Thickness (t); extent (l)	Wireline-log Attribute	Interpretation
A	A1	Parallel-laminated mudstone with occasional siltstone inputs. Monospecific pattern of disorder bivalves parallel to bedding.	t= 30-425 cm l= 6 to 29 km	GR= 41-308 API DT= 225-355 μsm^{-1} NPHI= 0.17-0.45 v/v RHOB= 2280-2820 gcm^{-3}	Restricted marine shale
	A2	Interbedded claystone and very fine-grained sandstone; non-parallel and wavy lamination. Scarcely bivalve shells oriented parallel to bedding.	t= 10-725 cm l = 8 km to 13 km	GR= 71-65 API DT= 189-268 μsm^{-1} NPHI=? RHOB= 2280-2820 gcm^{-3}	Muddy Shallow bay-fill
	A3	Fine to medium grained sandstone; moderately to well sorted grains. Wavy bedding, cross bedding, rare wave ripples	t= 60-370 cm l <8 km	GR= 18-46 API DT= 199-314 μsm^{-1} NPHI= 0.07-0.52 v/v RHOB= 1690-2745 gcm^{-3}	Sandy shallow bay-fill
	A4	Coarse to fine-grained sandstones with alternating upward fining to coarsening trend. Moderately sorted grains. Sparse sedimentary structures.	t= 250-500 cm l = 1.8 km to 4.2 km	GR= 7-35 API DT= 175-230 μsm^{-1} NPHI= 0.038-0.146 v/v RHOB= 2280-2820 gcm^{-3}	Marine channel-fill sandstones
B	B1	Upward-coarsening siltstone to fine-grained moderate sorted sandstones, with shell debris, and quartz granules.	t= 30-480 cm l = <2 km	GR= 18-80 API DT= 168-291 μsm^{-1} NPHI= 0.038-0.191 v/v RHOB= 2322-2723 gcm^{-3}	Distal lower shoreface
	B2	Very fine-fine grained, moderate to well sorted sandstone. Fine grained carbonaceous laminae, typically low angle cross beds.	t= 130-440 cm l = 1.7 km – 8 km	GR= 20-56 API DT= 179-277 μsm^{-1} NPHI= 0.048-0.168 v/v RHOB= 2314-2696 gcm^{-3}	Proximal lower shoreface
	B3	Coarsening upward, cross laminated, fine to medium grained, well sorted sandstone; consist carbonaceous fragments	t= 425-800 cm l = 1.7 km – 8 km	GR= 15-25 API DT= 250-275 μsm^{-1} NPHI= 0.09-0.113 v/v RHOB= 2271-2342 gcm^{-3}	Upper Shoreface
C	C1	Highly bioturbated siltstone to very fine sandstones, which has beds of rounded granules	t= 175-1010 cm l = 7.2 km – 19.6 km	GR= 20-80 API DT= 230-260 μsm^{-1} NPHI= 0.08-0.169 v/v RHOB= 2327-2521 gcm^{-3}	Distal mouth bar
	C2	Very fine to fine grained sandstones; low angle cross-bedding.	t= 290-775 cm l = < 5 km	GR= 12-58 API DT= 167-397 μsm^{-1} NPHI= 0.05-0.595 v/v RHOB= 1612-2705 gcm^{-3}	Proximal mouth bar
D	D1	Fining upward coarse to fine grained sandstone; stacked fining upward beds with rare coarse grained stringers.	t= 740-820 cm l = < 2 km	GR= 8-134 API DT= 235-335 μsm^{-1} NPHI= 0.14-0.460 v/v RHOB= 2284-2570 gcm^{-3}	Tidally influenced fluvial channel fill sandstone
	D2	Fining upward coarse to medium grained sandstone. Carbonaceous laminae and fragments. Sharp, and cohesive contact at bed base	t= 580 cm l = < 2 km	GR= 9-34 API DT= 241-297 μsm^{-1} NPHI= 0.14-0.289 v/v RHOB= 2168-2447 gcm^{-3}	fluvial channel fill sandstone
E	E1	Coal and carbonaceous shale. Basal contact, typically parallel.	t= 30-520 cm l = 6 km to 19.6 km	GR= 8-56 API DT= 313-427 μsm^{-1} NPHI= 0.24-0.529 v/v RHOB= 1930-2225 gcm^{-3}	coal
	E2	Alternating dark grey mud/claystone and siltstone to very fine-grained sandstone. Wavy to non-parallel lamination.	t= 60 cm l = < 2 km	GR= 32-60 API DT= 358-415 μsm^{-1} NPHI= 0.43-0.49 v/v RHOB= 1994-2148 gcm^{-3}	Coastal plain fines

Table 2

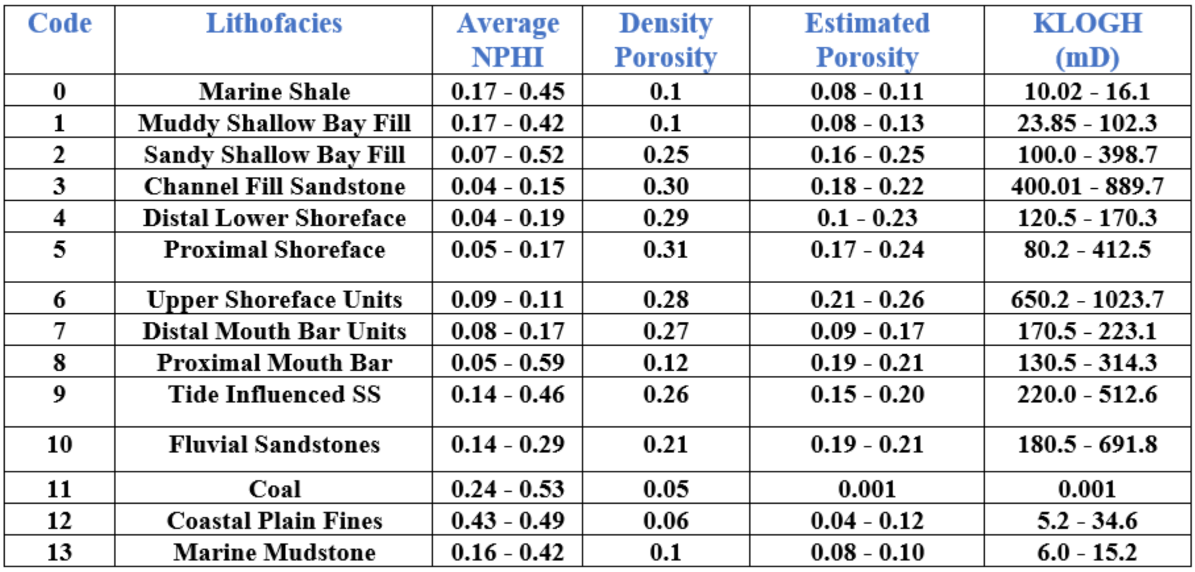
		Initial Conditions- GPM Input Parameters												
		Simulation Duration	Sediment Type Proportion (%)				Avg. Water Velocity	Avg. Sediment Velocity	Erodibility	Diffusion Coefficient	Avg. Sea Level	Turbidite Event Interval	Steady Flow Iteration	Sediment Movement
GPM Scenarios (GS)		(Ma– 0a) Years	Sand (Coarse)	Sand (Fine)	Silt	Clay	(m/a)	(m/a)			Interval (m)	(/years)	(/hrs)	Coefficient
	S1	0.02 – 0	25	25	25	25	0.11	0.03	0.35	0.11	30	2500	10	0.001
	S2	0.25 – 0	25	25	25	25	0.15	0.03	0.45	0.15	70	1000	15	0.012
	S3	0.5 – 0	25	25	25	25	0.11	0.02	0.55	0.11	120	1000	20	0.012
	S4	0.7 – 0.05	25	25	25	25	0.08	0.02	0.35	0.08	100	500	25	0.0011
	S5	1.5 – 0	15	35	30	20	0.15	0.04	0.50	0.15	80	5000	20	0.001
	S6	3.0 – 0	50	25	15	10	0.13	0.04	0.50	0.13	70	5000	30	0.0012
	S7	3.5 – 0	50	25	15	10	0.11	0.04	0.50	0.11	70	10000	15	0.001
	S8	4.0 – 0	50	25	15	10	0.13	0.04	0.50	0.13	90	5000	20	0.0015
	S9	4.5 – 0	15	45	25	15	0.1	0.02	0.45	0.1	50	10000	30	0.0012
	S10	5.0 – 0	15	45	25	15	0.12	0.02	0.45	0.12	55	10000	35	0.0013
	S11	5.5 - 0	15	45	25	15	0.12	0.02	0.45	0.12	40	5000	40	0.0013
	S12	6.0 – 0	15	45	25	15	0.1	0.02	0.45	0.1	60	10000	35	0.0011
	S13	6.5 – 0	10	25	55	10	0.13	0.03	0.48	0.13	100	20000	50	0.0010
	S14	7.0 – 0	10	25	55	10	0.16	0.03	0.48	0.16	40	20000	45	0.0011
	S15	7.5 – 0	10	25	55	10	0.13	0.03	0.48	0.13	40	20000	40	0.0012
	S16	8.0 – 0	10	25	55	10	0.15	0.03	0.48	0.15	30	10000	30	0.0010
	S17	8.5 – 0	10	25	45	20	0.14	0.02	0.45	0.14	50	50000	50	0.0010
	S18	9.0 – 0	30	30	18	22	0.13	0.02	0.52	0.13	60	25000	35	0.0012
	S19	9.5 – 0	30	40	12	18	0.12	0.02	0.55	0.12	55	25000	20	0.0013
	S20	10.0 - 0	30	42	18	10	0.11	0.01	0.40	0.11	50	5000	15	0.0011

	Sediment Property								
	Sediment Type	**Diameter**	**Density**	**Initial Porosity**	**Initial Permeability**	**Compacted Porosity**	**Compaction**	**Compacted Permeability**	**Erodibility**
	Coarse Grained Sand	1.0 mm	2.70 g/cm^3	0.21 m^3/m^3	500 mD	0.25 m^3/m^3	5000 KPa	50 mD	0.6
	Fine Grained Sand	0.1 mm	2.70 g/cm^3	0.3 m^3/m^3	100 mD	0.15 m^3/m^3	2500 KPa	5 mD	0.45
	Silt	0.01 mm	2.65 g/cm^3	0.38 m^3/m^3	50 mD	0.12 m^3/m^3	1200 KPa	2 mD	0.3
	Clay	0.001 mm	2.65 g/cm^3	0.48 m^3/m^3	5 mD	0.05 m^3/m^3	500 KPa	0.1 mD	0.15

Table 3

Lithofacies Classification		
Facies Code	**Lithofacies**	**Command Used in Petrel's Property Calculator**
0	Marine Shale	If(Sand_fine>=0.19 And Sand_fine<=0.21 Or Silt>=0.19 And Silt<=0.2 Or Clay>=0.2 And Clay<=0.21 Or Depth_of_deposition>=-82 And Depth_of_deposition<=-78)
1	Muddy Shallow Bay Fill	If(Sand_fine>=0.36 And Sand_fine<=0.38 Or Silt>=0.18 And Silt<=0.2 Or Clay>0.18 And Clay<=0.19 Or Depth_of_deposition>=-30 And Depth_of_deposition<=-20)
2	Sandy Shallow Bay Fill	If(Sand_coarse>=0.65 And Sand_coarse<=0.73 Or Sand_fine>=0.18 And Sand_fine<=0.22 Or Silt>=0.18 And Silt<=0.2 Or Clay>=0.17 And Clay<=0.18 Or Depth_of_deposition>=-3 And Depth_of_deposition<=0)
3	Channel Fill Sandstone	If(Sand_coarse>=0.5 And Sand_coarse<=0.68 Or Sand_fine>=0.23 And Sand_fine<=0.25 Or Silt>=0.17 And Silt<=0.18 Or Depth_of_deposition>=0 And Depth_of_deposition<=2)
4	Lower Shoreface Units	If(Sand_coarse>=0.19 And Sand_coarse<=0.31 Or Sand_fine>=0.19 And Sand_fine<=0.24 Or Silt>=0.4 And Silt<=0.48 Or Clay>=0.19 And Clay<=0.31 Or Depth_of_deposition>=-83 And Depth_of_deposition<=50)
5	Middle Shoreface Units	If(Sand_coarse>=0.32 And Sand_coarse<=0.53 Or Sand_fine>=0.25 And Sand_fine<=0.32 Or Silt>=0.26 And Silt<=0.32 Or Clay>=0.19 And Clay<=0.21 Or Depth_of_deposition>=-38 And Depth_of_deposition<=-12)
6	Upper Shoreface Units	If(Sand_coarse>=0.53 And Sand_coarse<=0.72 Or Sand_fine>=0.28 And Sand_fine<=0.33 Or Silt>=0.16 And Silt<=0.21 Or Depth_of_deposition>=-10 And Depth_of_deposition<=6)
7	Distal Mouth Bar Units	If(Sand_fine>=0.23 And Sand_fine<=0.27 Or Silt>=0.38 And Silt<=0.43 Or Clay>=0.19 And Clay<=0.21 Or Depth_of_deposition>=-95 And Depth_of_deposition<=-80)
8	Proximal Mouth Bar Units	If(Sand_coarse>=0.53 And Sand_coarse<=0.71 Or Sand_fine>=0.27 And Sand_fine<=0.32 Or Silt>=0.16 And Silt<=0.21 Or Clay>=0.06 And Clay<=0.07 Or Depth_of_deposition>=-30 And Depth_of_deposition<=-27)
9	Tide Influenced Sandstones	If(Sand_coarse>=0.53 And Sand_coarse<=0.71 Or Sand_fine>=0.26 And Sand_fine<=0.31 Or Silt>=0.35 And Silt<=0.41 Or Depth_of_deposition>=-5 And Depth_of_deposition<=1)
10	Fluvial Channel Sandstones	If(Sand_coarse>=0.54 And Sand_coarse<=0.56 Or Sand_fine>=0.27 And Sand_fine<=0.29 Or Silt>=0.19 And Silt<=0.21 Or Depth_of_deposition>=-2 And Depth_of_deposition<=2)
11	Coal	Estimated as background attribute
12	Coastal plain fines	If(Silt>=0.31 And Silt<=0.43 Or Clay>=0.31 And Clay<=0.35 Or Depositional_depth>=-100 And Depositional_depth<=-40)
13	Marine Mudstone	If(Sand_fine>=0.36 And Sand_fine<=0.38 Or Silt>=0.4 And Silt<=0.52 Or Clay>=0.45 And Clay<=0.78 Or Depth_of_deposition>=-105 And Depth_of_deposition<=-90)

Table 4



Code	Lithofacies	Average NPHI	Density Porosity	Estimated Porosity	KLOGH (mD)
0	Marine Shale	0.17 - 0.45	0.1	0.08 - 0.11	10.02 - 16.1
1	Muddy Shallow Bay Fill	0.17 - 0.42	0.1	0.08 - 0.13	23.85 - 102.3
2	Sandy Shallow Bay Fill	0.07 - 0.52	0.25	0.16 - 0.25	100.0 - 398.7
3	Channel Fill Sandstone	0.04 - 0.15	0.30	0.18 - 0.22	400.01 - 889.7
4	Distal Lower Shoreface	0.04 - 0.19	0.29	0.1 - 0.23	120.5 - 170.3
5	Proximal Shoreface	0.05 - 0.17	0.31	0.17 - 0.24	80.2 - 412.5
6	Upper Shoreface Units	0.09 - 0.11	0.28	0.21 - 0.26	650.2 - 1023.7
7	Distal Mouth Bar Units	0.08 - 0.17	0.27	0.09 - 0.17	170.5 - 223.1
8	Proximal Mouth Bar	0.05 - 0.59	0.12	0.19 - 0.21	130.5 - 314.3
9	Tide Influenced SS	0.14 - 0.46	0.26	0.15 - 0.20	220.0 - 512.6
10	Fluvial Sandstones	0.14 - 0.29	0.21	0.19 - 0.21	180.5 - 691.8
11	Coal	0.24 - 0.53	0.05	0.001	0.001
12	Coastal Plain Fines	0.43 - 0.49	0.06	0.04 - 0.12	5.2 - 34.6
13	Marine Mudstone	0.16 - 0.42	0.1	0.08 - 0.10	6.0 - 15.2

Porosity and Permeability Prediction through Forward Stratigraphic Simulations Using GPM^{TM} and Petrel^{TM}: Application in Shallow Marine Depositional Settings.

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Abstract

The forward stratigraphic simulation approach ~~is~~was used ~~in this work~~ to ~~predict~~model porosity and permeability attributes in the Volve field, Norway. This was achieved by ~~using~~applying spatial data from the forward stratigraphic ~~model~~simulation to control ~~the~~property distribution ~~of porosity and permeability~~ in the ~~3-D grid~~reservoir model. Building a ~~subsurface property~~ reservoir model that fits data at different locations ~~in a hydrocarbon reservoir~~ is a task associated with high levels of uncertainty. ~~An appropriate means to~~To minimise property representation uncertainties ~~is to use~~in a reservoir model, geologically realistic sediment distribution ~~and or stratigraphic~~ patterns must be developed to predict lithofacies units and ~~related~~associated petrophysical properties. The workflow ~~used are~~is in three parts; first, the geological process modeling (GPM^{TM}) software developed by Schlumberger was used to simulate scenarios of sediment transportation and deposition in the model area. Secondly, an estimation of lithofacies proportions in the stratigraphic model was done using the property calculator tool in the Petrel^{TM} software. Finally, porosity and permeability values ~~are~~were assigned to corresponding lithofacies-associations in the forward model to produce a forward stratigraphic-based petrophysical model. Results show a lithofacies distribution that is controlled by sediment diffusion rate, sea level variation, flow rate, wave processes, and tectonic events. This observation is consistent with real-world events, were variation in sea level~~ changes~~, volume of sediment input, and accommodation ~~space~~ control the ~~kind~~build-up of stratigraphic sequence~~ formed~~. Validation wells~~ prefixed~~, VP1 and VP2 located in the original Volve field petrophysical model and the forward stratigraphic-based models show a good match in porosity and permeability attributes at 5 m vertical sample intervals. ~~By reducing the level of property uncertainty between wells through~~The resultant, forward stratigraphic~~ modeling, an improved~~-based, porosity and

For

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permeability models suggest that forward stratigraphic simulation outputs can be ~~achieved for an efficient field development strategy~~integrated into classical modeling workflows to improve subsurface property representation, and well planning strategies.

For

Introduction

The distribution of reservoir properties such as porosity and permeability is a direct function of a complex combination of sedimentary, geochemical, and mechanical processes (Skalinski & Kenter, 2014). The impact of reservoir petrophysics on ~~hydrocarbon field development and depletion~~well planning and extraction strategies makes it imperative to use reservoir modeling techniques that present realistic property variations in 3-D models (~~e.g. ~~Deutsch and Journel, 1999; Caers and Zhang, 2004; Hu & Chugunova, 2008). Typically, reservoir modeling ~~tasks ~~require continued property modification until an a appropriate match to known subsurface data is obtained. However, acquisition of subsurface datasets is costly, thus restricts data collection and subsurface modeling ~~condition~~conditions. Several studies, e.g. Hodgetts et al. (2004) and Orellana et al. (2014) have demonstrated that stratigraphic patterns, and therefore petrophysical attributes can be ~~fairly well understood~~extrapolated from seismic, outcrop and well logs. However, this notion is limited by the absence of ~~an ~~accurate and reliable 3-D depositional ~~model~~models to guide ~~the distribution of ~~property ~~variability~~modeling in reservoir units (Burges et al. 2008). Reservoir modeling techniques with the capacity to integrate forward stratigraphic simulation outputs with stochastic modeling techniques for subsurface property modeling will improve reservoir heterogeneity characterization, because they more accurately produce geological realism than the other modeling methods (Singh et al. 2013). The use of geostatistical-based methods to represent the spatial variability of reservoir properties have been widely accepted in many exploration and production projects (e.g. Kelkar and Godofredo, 2002). In geostatistical~~ base~~ modeling methods, an alternate numerical 3-D model (i.e. realizations) is derived to demonstrate different scenarios of property distribution that can be conditioned to well data (Ringrose & Bentley, 2015). ~~Typically, subsurface~~Reservoir modeling practioners are normally faced with the challenge of getting a lot of subsurface data to deduce reliable variogram models as a result of cost, therefore introducing a significant level of uncertainty in a reservoir model (Orellena et al. 2014). The advantages of applying geostatistical approaches in populating propoerties in reservoir models is well established (e.g. Deutsch and Journel, 1999; Dubrule, 1998), but the geostatistical-based method tends to confine reservoir property models to known data and rarely realize geological realism to capture sedimentary that have led to reservoir formation (Hassanpour et al. 2013). In effect, the geostatistical modeling technique is unable to reproduce a long-range ~~continuity of~~continuous reservoir properties that are essential for generating realistic reservoir connectivity models (Strebelle & Levy, 2008). Based on lessons from a previous work (e.g. Otoo and Hodgetts, 2019), the forward stratigraphic simulation approach ~~is again~~was applied in this contribution to predict lithofacies units, porosity, and ~~petrophysical~~permeability properties in a 3-D model. An important aspect of this work is the use of variogram parameters from forward stratigraphic-based synthetic wells to populate petrophysical properties~~, especially within inter-well regions of~~ in the reservoir ~~under study~~model grid. Forward stratigraphic modeling involves the uses morphodynamic rules to derive sedimentary depositional ~~patterns~~trends to reflect stratigraphic ~~observations~~patterns in ~~real~~known data. The approach is driven by the principle that multiple sedimentary process-based simulations in a 3-D framework will ~~most likely~~ improve ~~our understanding on spatial variation of~~ facies, ~~as well as~~and petrophysical ~~properties~~property distribution in a geological ~~system~~model.

The ~~sedimentary system, Hugin formation makes up the main~~ reservoir interval ~~in the Volve field. According to studies~~under study is located within the Hugin formation. Studies by Varadi et al. (1998); Kieft et al. (2011), suggest that the ~~Hugin~~ formation ~~is made up~~consist of a complex depositional architecture of waves, ~~tides~~tidal and ~~riverine riverine~~fluvial processes~~; suggesting~~. This indicates that a single depositional model will not be adequate to produce a realisitc lithofacies distributions model of the area. Furthermore, the complicated Syn-depositional rift-related faulting system, significantly influence the stratigraphic architecture (Milner and Olsen, 1998). The focus of this ~~study~~work is to produce a depositional sequence in the shallow marine environment by using a forward stratigraphic modeling approach in the GPM^{TM} (Schlumberger, 2017), and use variogram parameters from the forward model to control porosity and permeability property representation in ~~a 3-D~~the Volve field model grid.

Study Area

The Volve field (Figure 1), located in Block 15/9 south of the Norwegian North Sea is Jurassic in age (i.e. late Bajocian to Oxfordian) with the Hugin Formation as the main reservoir unit from which hydrocarbons are produced (Vollset and Dore, 1984). The Hugin formation is made up of shallow marine to marginal marine sandstone deposits, coals, and a significant influence of wave events that tend to control lithofacies distribution in the formation (Varadi et al. 1998; and Kieft et al. 2011). Several studies, e.g. Sneider et al. (1995), and Husmo et al. (2003) associate sediment deposition in the Hugin system to a rift-related subsidence and successive flooding during a large transgression of the Viking Graben within the Middle to Late Jurassic period. Previously it was interpreted to comprise of marine shoreface, lagoonal and associated coastal plain, back-stepping delta-plain and delta front deposits (e.g. Cockings et al. 1992; Milner and Olsen, 1998), but recent studies, e.g. Folkestad and Satur, (2006) suggest the influence of a strong tidal event, which introduces another dimension in property modeling of the reservoir. The thickness of the Hugin formation is estimated to range between 5 m and 200 m but can be thicker off-structure and non-existent on structurally high segments as a result of post-depositional erosion (Folkestad and Satur, 2006).

Based on studies by Kieft et al. (2011), a summarised sedimentological delineation within the Hugin formation is presented in **Table 1**. Lithofacies-association codes A, B, C, D, and E used in the classification represents bay fill units, shoreface sandstone facies, mouth bar units, fluvio-tidal channel fill sediments, and coastal plain facies units respectively. In addition a lithofacies association prefixed code F was interpreted to consist of open marine shale units, mudstone with occasional siltstone beds, parallel laminated soft sediment deformation that locally develop at bed tops. The lateral extent of the code F lithofacies package in the Hugin formation is estimated to be 1.7 km to 37.6 km, but the total thickness ~~have~~of code F lithofacies is not ~~been completely penetrated~~known (Folkestad & Satur, 2006).

Data and Software

This work is based on description, and interpretation of petrophysical datasets in the Volve field by Statoil, now Equinor. Datasets include 3-D seismic ~~data~~sections, and a suite of 24 wells that consist of formation pressure data, core data, and sedimentological logs. Previous works such as Folkestad & Satur, (2006) and Kieft et al. (2011) show varying grain size, sorting, sedimentary structures, bounding contacts of sediment matrix that play a significant part of the reservoir petrophysics. Grain size, sediment matrix and the degree of sorting will typically drive the volume of void created, and therefore the porosity and permeability attributes . Wireline-log attributes such as gamma ray (GR), sonic (DT), density (RHOB), and neutron-porosity (NPHI) were used to distinguish lithofacies units, stratigraphic horizons and zones that are required to build the 3-D property model. Porosity, and permeability models, of the Volve field, were generated in Schlumberger's Petrel^{TM} software. Importantly, this work also seeks to produce geologically realistic depositional architecture that is comparable to a real-world stratigraphic framework in a shallow marine environment. Deriving a representative 3-D stratigraphic model of the reservoir allows us to deduce geometrical and variogram parameters as input datasets in actual subsurface property modeling.

~~The~~Schlumberger's geological process modeling (GPM^{TM}) software ~~developed by Schlumberger~~ was used to undertake twenty forward stratigraphic simulation in an attempt to replicate ~~the~~ depositional processes that resulted in the build-up of the reservoir interval under study. Simulations were constrained to twenty scenarios because the desired stratigraphic sequence and associated sediment patterns were achieved at the fourth simulation. The main criteria for evaluating the realistic nature of a stratigraphic model was to compare it to the depositional sequence observed in the seismic section in Figure 3b. Several process modeling software packages exist and have been applied in similar studies; e.g. Delft3D-Flow^{TM}; Rijin & Walstra, (2003); DIONISOS^{TM}; Burges et al. (2008). The geological process modeling (GPM^{TM}) software was preferred because of the availability of software license, and also the ease in integrating of its outputs into the property modeling workflow in Petrel^{TM}.

Methodology

The workflow (Figure 2a) combines the stratigraphic simulation capacity of the GPM^{TM} software in different depositional settings, and the property modeling tools in Petrel^{TM} to predict the distribution of porosity and permeability properties away from well data. Three broad steps have been used here to achieve this goal; (i) forward stratigraphic simulation (FSS) in GPM^{TM} software (2019.1 version), (ii) lithofacies classification using the calculator tool in Petrel^{TM}, and (iii) lithofacies, porosity, and permeability modeling in Petrel^{TM} (2019.1 version).

Process Modeling in GPM^{TM}

The GPM^{TM} software consist of different geological processes that are designed to replicate sediment deposition in clastic and carbonate environments. ~~Example, the steady flow process is efficient for simulating sediment deposition in fluvial bodies, whilst the unsteady flow process control sediment transportation from the basin slope into deep-water basin setting, largely in the form of basinal floor fan units. Previous~~For example, previous studies, e.g. Kieft et al, (2011) identified the influence of riverine (fluvial), and wave processes in the genetic structure of sediments in the Hugin formation. These geological processes could be very rapid depending on accommodation ~~space~~ generated as a result of sea level variation, and or sediment composition and flow intensity. Sediment deposition, and its response to post-depositional sedimentary and tectonic processes are significant in the ultimate distribution of subsurface lithofacies units~~; hence the variation of input parameters to increase our chance attaining~~ . To attain stratigraphic outputs that fall within ~~acceptable limits of what may exist~~the depositional architecture captured in the ~~natural order.~~seismic section (Figure 3b), the input parameters were varied as illustrated by different scenarios in Table 2. The simulation generated geologically realistic stratigraphic ~~frameworks~~trends, but also revealed some limitations, such as instability in the simulator when more than three geological processes and sub-operations run at a time. In view of this, the diffusion and tectonic processes ~~are constant features whiles~~were combined with other processes ~~like~~such as steady flow, unsteady flow, and sediment accumulation~~, compaction were varied~~ to replicate the Volve field stratigraphic depositional scenarios.

Steady Flow Process

The steady flow process in GPM simulate flows that changes slowly over a period, or sediment transport scenarios where flow velocity and channel depth do not vary abruptly; e.g. rivers at normal stage, deltas, and sea currents. The steady flow process can be specified to a desired setting in the "run sedimentary simulation" dialog box in the Petrel^{TM} software (version 2017.1 and above). Considering the influence of fluvial activities in the build-up of the Hugin formation, it was important to capture its impact on the resultant simulated output. To attain stability in the simulator, it is advisable to undertake preliminary runs to ascertain the appropriateness of input parameters that will be used in the simulation. For steady flow process, a boundary condition must be specified at the edges of the model. For example in an open flow system, negative integers (i.e. values below zero) must be assigned to the edges of the hypothetical paleo-surface to allow water to enter and leave the simulation area.

Unsteady Flow Process

The unsteady flow process can model flows that are periodic, and run for a limited time; for example, in turbidites where velocity of flow and depth changes abruptly over time. The unsteady flow process algorithm is set up to apply a number of fluid elements, that are affected by gravity, and by friction against the hypothetical topographic surface. A contribution on the application of the unsteady in stratigraphic simulation, and how its settings can be configured to attain geological realistic outcomes is discussed in Otoo and Hodgetts, (2019).

Diffusion Process

The diffusion process can effectively replicate sediment erosion from areas of higher slope (i.e. source location) and their deposition to lower elevation of the model area. Sediment dispersion in the diffusion process is carried out through erosion and transportation processes that are driven by gravity in the simulator. The diffusion process is based on the assumption that sediments are transported downslope at a proportional rate to the topographic gradient; therefore making fine grained sediments easily transportable than coarse grained sediments. Diffusion is controlled by two parameters; (i) diffusion coefficient, which controls the strength of the diffusion, and (ii) diffusion curve that serves as a unitless multiplier in the algorithm. The governing equation for the diffusion process is:

$\frac{\partial z}{\partial t} = k\nabla^2 z$, where **z** is topographic elevation, **k** the diffusion coefficient, **t** for time, and $\nabla^2 z$ is the laplacian.

Sediment Accumulation

In the GPM™ software, sediment source can be set to a point location or considered to emanate from a whole area. Sediment accumulation deals with sediment deposition via an areal source. For example, where a lithology is interpreted to be uniformly distributed, the sediment accumulation process can be used to replicate such depositional scenario. The areal input rates for each sediment type (e.g. coarse grained, fine grained sediments) used in the accumulation process must be specified in the settings. Specifying the areal rates for each sediment is important because the software is configured to use the value of the surface at each cell in the model grid and multiplies it by a value (i.e. value from a unitless curve) at each time step in the simulation to estimate the thickness of sediments accumulated or eroded from a cell in the model.

Parameters for Forward Stratigraphic Simulation

A realistic reproduction of stratigraphic patterns in the study area will require input parameters ~~(also known as~~or initial conditions~~). These include: a~~ such as: hypothetical paleo-topography, sea level curves, sediment source location and distribution curve, tectonic ~~events~~event maps (i.e. subsidence and uplift), and sediment mix velocity. The application of these input parameters in ~~the~~ GPM™ ~~simulator~~, and their influence on the resultant stratigraphic framework are ~~explained~~discussed below.

Hypothetical Paleo-Surface: The hypothetical paleo-topographic surface, on which the simulation ~~commences~~evolves was inferred from the seismic section. ~~Here, we assume~~This is done with the assumption that the present day stratigraphic surface~~, also referred to as the~~ (i.e. paleo shoreline in Figure 3a) occurred as a result of basin filling through different geological periods. Since the hypothetical topography generated from the seismic section have undergone various phases of subsidence and uplifts~~ over time~~, the paleo topographic surface used in this work does not present an accurate description of the basin at the period of sediment deposition. To ~~mitigate~~obtain an appropriate paleo-topographic for this ~~uncertainty, 5~~task, , five paleo topographic surfaces (TPr) were generated ~~stochastically~~ by adding or subtracting elevations from the inferred paleo topographic surface~~ or base topography~~ (see Figure 4g) using the equation: TPr = Sbs + EM, where, Sbs is the base surface scenario (in this instance, scenario 6), and EM an elevation below and above the base surface. ~~In this work,~~Paleo-topographic surface in scenario 3 (figure ~~3d~~4d) was ~~used as the paleo-topographic surface~~selected, because it ~~produced~~controlled the development of stratigraphic sequences that fit the conceptual knowledge of depositional framework as observed in the seismic section (Figure 5d).

Sediment Source Location: Based on regional well correlations in previous studies (e.g. Kieft et al. 2011), and seismic interpretation of the basin structure~~ interpreted from seismic data~~, the sediment entry point~~ for this task~~ was placed in the north-eastern section of the hypothetical paleo-topography. Since the exact sediment entry point is ~~uncertain~~not known, multiple entry points were placed at 4 ~~m~~km radius around the primary location in (Figure 3c), in order to capture possible sediment source locations. The source position is characterised by positive integers (i.e. values greater than zero) to enable fluid flow to other parts of the simulation surface.

Sea Level: ~~Primarily, the sea~~Sea level variation ~~relative to elevation~~ was inferred from published studies and facies description in shallow marine depositional environments (e.g. Winterer and Bosellini, 1981). ~~Considering the limitations~~To attain stability in the ~~software~~simulator, we assumed a sea level ~~of~~that range between 15 m to 45 m; averaging 30 m for short simulation runs, e.g. 5000 to 20000 years~~ to attain stability in the simulator and~~. The sea level was varied ~~it accordingly~~ with increasing duration of the simulation~~.~~ (illustrated in Table 2). The peak sea-level in the simulation represents the maximum flooding surface~~,~~ (Figure 5d), and therefore ~~an~~the inferred sequence boundary in the geological process model.

Diffusion and Tectonic Event Rates: The sediment mix proportion~~ and~~, diffusion rate ~~for the simulation~~ and tectonic event functions were ~~stochastically~~ inferred from previous studies (e.g. ~~Burges et al., 2008), primarily to attain a prograding and or aggrading clinoforms features that are noticeable in real world geological outcrops. The subsidence and uplift rates were kept constant in most part of the model . The~~

~~functions are inferred from published works; e.g.~~ Walter, 1978; Winterer and Bosellini, 1981, and Burges et al., 2008). The diffusion and tectonic event rates are increased or reduced to produce a stratigraphic model that fit our knowledge of the basin evolution. ~~The simulation parameters applied (**Table 2**) were generated randomly using the initial run (**Figure 6a**) as a guide. The guiding principle for parameter selection is their capacity to produce stratigraphic outputs that depict different depositional scenarios in the shallow marine setting.~~A key criteria for selecting parameters is their capacity to produce stratigraphic outputs that depict depositional scenarios in the study area. For example, in scenario 1 (Figure 6a), the early stages of clinoform development show resemblance to interpreted trends in the seismic section (Figure 3b). As a result, input figures that were higher and lesser than those used in generating scenario 1 were generated to serve as the simulation parameters for the twenty scenarios. In scenario 1, a diffusion coefficient of 8 m2/a was used to produce a realistic clinoform build-up, so the figure was varied with +/-5 to obtain figures that could improve the model derived in scenario 1. The initial topography (TP_r) was kept constant throughout a simulation, but wave events, steady/unsteady flow, diffusion and tectonic events use curve functions to provide variations within the simulation. A sudden change in subsidence rate tends to constrain coarse to medium sediments at proximal distance to source location than in scenarios where the rate of subsidence was made gradual.

The influence of input parameters in the simulation is evident whenever there is a slight change of value in sediment diffusion, and tectonic rates or dimension of the hypothetical topographic surfaces. For example, sediment source position has a strong impact on the extent and depth to which sediments are deposited in the basin. Shifting the source point to the mid-section of the topography (i.e. the mid-point of the topography in a basin-ward direction) resulted in the accumulation of distal elements that are identical to turbidite lobe systems. This is consistent with morphodynamic experiments ~~(e.g.~~by de Leeuw et al., 2016~~)~~, where ~~abrupt~~sediment discharge ~~of sediments~~ from the basin slope leads to the build-up of basin floor fan units. ~~Stratigraphic patterns generated using different input parameters provides 3-D perspective into subsurface property variations under alternating initial conditions.~~

Property Classification in Stratigraphic Model

In our opinion, the most appropriate model in this work is **Figure 5d**. This is because, when compared to depositional description in studies such as Folkestad and Satur (2006); kieft et al., (2011), it produced a stratigraphic sequence that mimics the depositional sequence in the ~~shallow marine depositional environment under study~~study area. The stratigraphic model was converted into a 3-D format, 20 m x 20 m x 2 m grid cells in order to be used in the property modeling tool in Petrel^{TM}. Lithofacies, porosity, and permeability properties are characterized in the stratigraphic using a rule based approach (**Table 3**). Sediment distribution in each time step of the simulation were stacked into a single zone framework to attain a simplified model. This was done with the assumption that sedimentary processes that lead to the final build-up of genetic related units within zones of the ~~forward stratigraphic architecture~~model will not vary significantly over the simulation period. Property classification in the model was achieved with the property calculator tool in ~~Petrel~~Petrel^{TM}. The classification ~~is~~was driven by depositional depth, geologic flow velocity, and sediment distribution patterns as indicated in **Figure 7**. Lithofacies representation in the stratigraphic model was based on the sediment grain size pattern, and proximity to sediment source. For example, shoreface lithofacies units were characterized using medium-to-coarse grained sediments ~~to that are~~ , which accumulate at proximal distance to the sediment source~~, whiles~~. In contrast, mudstone units ~~are constrained to the distal parts of the stratigraphic model, where~~ were restricted to fine grained sediments that accumulate at ~~the end~~distal section of the simulation domain.

~~Porosity and~~ Using published studies by Kieft et al., (2011), porosity and permeability variations in the stratigraphic model were estimated from ~~published~~ wireline-log attributes ~~(e.g. Kieft et al., 2011), which is~~such as gamma ray, neutron, sonic, and density logs outlined in Table 1. ~~Based~~In previous studies on ~~petrophysical report of~~ the Sleipner Øst, and Volve field (~~Statoil~~e.g. Equinor, 2006~~), a deduction was made~~; Kieft et al., 2011), Shoreface deposits were identified to ~~the effect that high net-to-gross zones will be associated with~~make up the best ~~quality~~ reservoir units~~; classified as~~ , whilst lagoonal deposits formed the worst reservoir units. Using this as guide, shoreface ~~lithofacies units, whilst low net-to-gross zones were interpreted to be connected with high proportions of shale or~~sandstone units and mudstone

~~deposits.~~/shale units in the forward stratigraphic model were characterized as best and worst reservoir units respectively. The porosity and ~~184~~ permeability values in Table 4 were derived from equations in Statoil's petrophysical report of the Volve ~~185~~ field (~~Statoil~~Equinor, 2016):

$\O_{er} = \O_D + \alpha$ ~~x~~. $(NPHI - \O_D) + \beta;$ where $\O_{er}$ is the estimated porosity range, $\O_D$ is density porosity, α and β are regression constants; ranging between -0.02 – 0.01 and 0.28 – 0.4 respectively, $NPHI$ is neutron porosity. In instances where NPHI values for lithofacies units is not available from the published references, an average of 0.25 was used.

$KLOGH_{er} = 10^{(2 + 8 * PHIF - 5 * VSH)}$; where $KLOGH_{er}$ is the estimated permeability range, VSH is the volume of clay/shale in the lithofacies unit, and $PHIF$, the fractured porosity. The VSH range between 0.01 – 0.12 for the shoreface units, and 0.78 – 0.88 for lagoonal deposits.

Property Modeling in Petrel^{TM}

The workflow (**Figure 2b**) used for subsurface property (e.g. lithofacies, and petrophysical) modeling in Petrel^{TM} is extended to represent lithofacies, porosity, and permeability properties in the forward stratigraphic model. These processes include:

1. Structure modelling: identified faults within the study area are modelled together with interpreted surfaces from seismic and well data to generate the main structural framework, within which the entire property model will be built. The procedures involve modification of fault pillars and connecting fault bodies to one another to attain the kind of fault framework interpreted from seismic and core data.

(2) Pillar gridding: a "grid skeleton" that is made up of a top, middle and base architectures. Typically, ~~there are~~ pillars ~~which~~ join corresponding corners of every grid cell of the adjacent ~~-~~grid~~, forming~~ to form the foundation ~~of~~for each cell within the model~~; hence its nomenclature as a corner point gridding.~~. The prominent orientation of faults (i.e. I-direction) within the model ~~is~~area generally

trends in a N-S and NE-SW direction, so the "I-direction" was set to the ~~major~~NNE-SSW direction ~~along which grid cells align.~~to capture the structural description.

(3) Horizons, Zones and Vertical Layering: stratigraphic horizons and subdivisions (zones) delineates the geological formation's boundaries. As stratigraphic horizons are inserted into the model grid, the surfaces are trimmed iteratively and modified along faults to correspond with displacements across multiple faults. Vertical layering on the other hand defines the thicknesses and orientation between the layers of the model. ~~In order~~Layers in this context describes significant changes in particle size or sediment composition in a geological formation. Using a vertical layering scheme makes it possible to honour the fault framework, pillar grid and horizons that have been derived. ~~Cell~~A constant cell thicknesses ~~are~~of 1 m across the model was defined to control the vertical scale, in which subsurface properties such as lithofacies, porosity, and permeability attributes are modelled.

(4) Upscaling~~; which~~: involves ~~averaging~~the substation of ~~finer~~fine grid cells ~~in order to~~ with coarser grid cells. This is done to assign property values to ~~the~~ cells ~~and~~in order to evaluate which discrete value suits each a selected data point. ~~It also encompasses~~ One advantage of the ~~generation of coarser grids (i.e. lower resolution grids) in the geological model, in order~~upscaling procedure is to make ~~simulation~~the modeling process faster.

Porosity and Permeability Modeling

The~~ Volve field~~ porosity and permeability model that was built by Equinor for their operations in the Volve field was adopted as the base model. The model, which cover an area of 17.9 km^2 was generated with the reservoir management software (RMS), developed by Irap and Roxar (Emerson^{TM}). The~~ original~~ petrophysical model has a grid dimension of 108 m x 100 m x 63 m, and was compressed by 75.27% of cell size~~.~~ from an approximated cell size 143 m x 133 m x 84 m. To achieve a comparable model resolution ~~to~~as the ~~original~~Volve field porosity and permeability model, the forward stratigraphic output, which had an initial resolution of 90 m x 78 m x 45 m was upscaled to a ~~cell size~~grid of 107 m x 99 m x 63 m. Two options were explored with respect to the use of variogram parameters derived from forward model-based synthetic wells. Option 1 was to assign porosity and permeability values to the synthetic lithofacies wells ~~to~~that correspond to known facies-associations as indicated in **Table 4**. The synthetic wells with porosity and permeability data are placed in-between ~~actual well (~~known data~~)~~ locations to guide porosity and permeability property distribution in the model. For option 2, the best-fit forward stratigraphic model was populated with porosity, and permeability attributes using the major stratigraphic orientation captured in the seismic data (i.e. NE-SW; 240º) to control property distribution trends. Porosity and permeability were populated into the model by using the property modeling process in Petrel^{TM}. Porosity and permeability synthetic logs are then extracted from the forward stratigraphic output to build the porosity and permeability models (**Figure 8**). ~~The second option provided a broader framework for evaluating the reliability of forward stratigraphic simulation on property distribution in areas of sparse data.~~ Taking into account the possibility that vertical trends in options 1 and 2 will ~~most likely produce a~~be similar~~ trend~~ in a sampled interval, it is our opinion that option 2 will provide a viable 3-D representation of property variations in the major and minor directions of the forward stratigraphic model. Ten synthetic wells~~,~~ (SW), ranging between 80 m and a 120 m in total depth (TD) were positioned in the forward model to capture the vertical distribution of porosity-permeability at different sections of the stratigraphic model. ~~Typically, sediment distribution, and associated petrophysical attributes are directly related to depth within the geological model; thus aiding in the analysis of the most likely proportions of subsurface properties that match with observations in known well data.~~

The forward-based synthetic wells (**Figure 9 c**) with porosity and permeability logs were upscaled to ~~populated the original structural model using the sequential Gaussian simulation method.~~ populate the original structural model using the sequential Gaussian simulation method. Here, the synthetic wells derived from the stratigraphic model is to provide an additional well data for use in a traditional modeling workflow as was the case in the building of original Volve model. Considering the advantages of variogram-based modeling in relation to data conditioning, the idea was to get more wells into the model grid to control porosity and permeability distribution. Upscaling the synthetic well data in this context is to “transform” the data from 1-D into a 3-D framework to build the property model. Using the same structural model was to attain a comparable framework for evaluating the modeling outputs.

The variogram model (**Figure 10**), of dominant lithofacies units in the formation served as a guide in the estimation of variogram parameters from the forward model. A major and minor range of 1400 m and 400 m respectively, and an average sill value of 0.75 derived from forward stratigraphic-based synthetic wells were used to populate porosity and permeability properties in the model. Porosity models were derived with a normal distribution, whilst the permeability models were produced using a log-normal distribution and the corresponding porosity property for collocated co-kriging. Out of fifty model realizations, six realizations that showed some similarity to the original petrophysical model are presented (**Figure 11**). This was accomplished through visual and statistical comparison of zones in the original Volve field model, and the stratigraphic-based porosity/permeability models. The statistical approach involved a comparison of summary statistics from the original Volve model, and the porosity/permeability model generated through forward stratigraphic modeling. The visual comparison on the other hand looked at how geological realistic the output is, and if it conforms with our conceptual idea of the Volve field model.

Results

The stratigraphic model in stage 4 (**Figure 5d iv**) shows the final geometry after 700, 000 years of simulation time. Initial simulation produced a progradation sequence with foreset-like features (**Figure 5d i**). A sequence boundary, which indicates the highest sea level in the model separates the initial simulated output from the next prograding phase (**Figure 5d ii**). Initiation of an aggradation stacking pattern starts, and becomes prominent in stage 3 (**Figure 5d iii**). ~~This is~~These sequences are consistent with real-world scenario where sediment supply matchup with accommodation ~~space generated~~created as a result of the relative ~~constant~~ sea level rise within a period~~.~~ (e.g. Muto and Steel, 2000; Neal and Abreu, 2009). The diffusion process in GPM^{TM} was used to define the stratigraphic architecture before introducing additional geological processes such as steady flow, unsteady flow, wave events to capture the range of possible depositional styles that have been discussed in published literature (e.g. Folkestad & Satur, 2006; Kieft et al., 2011).

The impact of the stratigraphic simulation on porosity and permeability representation in the model ~~is~~was evaluated by comparing its outcomes to the ~~original~~Volve field porosity and permeability models ~~of the Volve~~by using two synthetic well ~~prefixed~~, VP1 and VP2~~. The synthetic well are~~, which were sampled vertically at a 5 m intervals ~~vertically to estimate the distribution of porosity and permeability attributes along wells.~~. Considering that the ~~original porosity and permeability~~Volve field petrophysical model (**Figure 11a**) have undergone phases of history matching to ~~enable~~enhance well planning, and ~~guide~~ production strategies in the Volve field, it is reasonable to assume that porosity and permeability distribution in the ~~Volve field~~ petrophysical model will be geologically realistic and less uncertain. A good match in porosity was observed in validation wells that penetrate the model realizations; R14, R20, R26, R36, R45, and R49 (**Table 5a**). ~~The vertical distribution (~~Figure 12 ~~) of~~shows the porosity variation (0.18 – 0.24) in some selected ~~model~~ realizations ~~shows~~. This value (i.e. 0.18 – 0.24) is within the range of porosity estimates in the Volve field (Equinor, 2016). In view of the limitation in making variations within a ~~modal distribution range (i.e 0.18 – 0.24) that is consistent with the original model. The~~simulation run in GPM^{TM}, the forward stratigraphic-based model ~~have been~~(FSM) was derived with an assumption that variogram parameters, stratigraphic inclination within zones will remain constant. ~~However~~As a result, the original petrophysical model ~~takes into account~~, which involve other measured attributes~~, which could be~~ within the ~~main driver of~~ stratigraphic zone was not considered in the ~~differences in~~ forward stratigraphic modeling-based permeability ~~estimates~~model, hence the major variations noted in **Table 5b.** Typically, a petrophysical model like the Sleipner Øst and Volve field model will take into account other sources of data ~~such as~~. For example, data from a special core analysis (SCAL) ~~and other petrophysical evaluations from~~ will improve the reservoir ~~section, so~~petrophysics assessment. Considering that the FSM approach did not involve these additional information from the formation, it is ~~reasonably reliable~~reasonable to suggest that the forward stratigraphic-based porosity and permeability models have been adequately conditioned to known subsurface data.

Discussion

~~The results~~Results show the influence of sediment transport rate, (or ~~in this example,~~ diffusion rate~~,~~), initial basin topography and ~~proximity to~~ sediment source location on stratigraphic simulation in the GPM^{TM} software. ~~Notably,~~Similar to other studies (e.g. Muto & Steel, 2000; Neal & Abreu, 2009), a variations in sea level controls the volume of sediment that could be retained or transported further into the basin; therefore controlling the kind of stratigraphic sequences that are generated. In a related work by Burges et al. (2008), it was established that~~; for example,~~ a sediment-wedge topset width was directly linked to the initial bathymetry, in which the sediment-wedge structure was formed, as well as the correlation between sediment supply and accommodation rate. This is in line with observations in this ~~work~~study, where the initial sediment deposit control the geometry of subsequent phase of depositions. ~~Since the~~ The uncertainty of initial conditions ~~of~~used in this ~~basin is uncertain,~~ work led to the generation of multiple ~~simulation~~forward stratigraphic scenarios ~~were carried out~~ to account for the range of bathymetries that may have influenced ~~the build-up of sediments~~sediment transportation to form the present day Hugin formation. The simulation produced well defined ~~clinoform~~sloping depositional surfaces in a stratigraphic architecture (i.e. clinoforms) and sequence boundaries that depict the pattern observed in the seismic data. ~~As indicated~~Indicated in ~~other~~previous studies, (e.g. Allen and Posamentier, 1993; Ghandour and Haredy, 2019) sequence stratigraphy is vital in the characterization of lithofacies in ~~shallow marine settings; hence,~~sedimentary systems. Therefore, a reproduction of stratigraphic sequence in 3-D, using the forward stratigraphic ~~simulation outputs~~modeling approach in GPM^{TM} provide a good framework to ~~better understand the variation of lithofacies units in the~~analyse property variations in a reservoir~~ through a 3-D perspective.~~. A porosity-permeability model ~~that match~~matching the original petrophysical model was produced using synthetic porosity and permeability logs from the forward stratigraphic model as input datasets in the sequential Gaussian simulation algorithm. As mentioned previously, this exercise did not take into account variations in the layering scheme that develops in different zones of the stratigraphic model. Under this circumstance, we concede that there is a possibility to overestimate and or underestimate porosity and permeability properties as observed in some sampled intervals of the validation wells. In view of this, it is our suggestion that forward stratigraphic simulation outputs should be applied as additional data to understand sediment distribution patterns, and associated vertical and horizontal petrophysical trends in the depositional environment than using its outputs as an absolute conditioning data in subsurface property modeling.

~~The assumptions~~Assumptions made ~~in~~with respect to the type of geological processes, and input parameters to use in the simulation ~~significantly~~certainly differ from what ~~may have~~ existed during the period of deposition. ~~Applying~~So, applying stratigraphic models that fit a basin scale description to a smaller scale reservoir context presents another degree of uncertainty in the approach used here. For example, in their study, Burges et al., (2008) shows that the diffusion geological process fits the description of large scale sediment transportation; suggesting that an extrapolation of its outputs into a well-scale framework could produce results that deviate from the real world ~~architecture~~distribution. In reality, sediment deposition into a geological basin is also controlled by mechanical and geochemical processes~~, which~~ that tend to modify a formations petrophysical attributes (Warrlich et al. 2010~~), hence, the application of~~). Therefore, using different geological processes and initial conditions to ~~produce different~~generate depositional scenarios~~, from which~~ is a ~~best fits stratigraphic framework of the reservoir can be selected. Many forward stratigraphic~~ reasonable approach. However, based ~~subsurface modeling studies (e.g.~~ on the approach limitation, which are also discussed in similar works (e.g. . Bertoncello et al. 2013; Aas et al. 2014; and Huang et al. ~~2015), have identified and discussed some limitations with the technique. Considering that similar challenges were faced in this work,~~2015) caution must be taken in using ~~the~~its outputs ~~from forward stratigraphic simulations~~ in real reservoir modeling; as ~~this~~it could lead to an increase ~~uncertainty~~ in ~~the~~property representation ~~of lithofacies and petrophysical properties.~~ bias.

The correlation between reservoir lithofacies and petrophysics have been examined in previous studies, e.g. Falivene et al. (2006) Hu and Chugunova, (2008), but the difference in predicted and actual reservoir character is less understood. This in large part is due to the absence of a realistic 3-D stratigraphic framework to guide reservoir property representation in geocellular models. It is our opinion that forward stratigraphic modeling methods provide reservoir modeling practitioners a better platform to generate appropriate 3-D lithofacies models to improve petrophysical property prediction in a reservoir, but its outputs should be used cautiously and together with verifiable subsurface patterns from seismic and well ~~data~~datasets.

Conclusion

In this paper, spatial data from a forward stratigraphic simulation is combined with subsurface data from the Volve field, Norway to constrain porosity and permeability distribution in inter-well regions of the model area. As caution, the forward stratigraphic simulation scenarios presented in this contribution do not ultimately prove that spatial and geometrical data derived from stratigraphic modeling can be used as absolute input parameters for a real-world reservoir modeling task. Uncertainties in the choice of initial condition and processes for the stratigraphic simulation led the variation of input parameters in order to attain a depositional architecture that is geologically realistic and comparable to the stratigraphic correlation suggested in some published studies of the study area. ~~Significantly, the~~The good match obtained from validation wells in the original and stratigraphic-based petrophysical model, leads us to the suggestion that an integration of variogram parameters from ~~real~~ well data and forward stratigraphic simulation outputs will improve property prediction in inter-well zones. This suggestion is supported by the idea that more conditioning data (well data) will increase the chance of producing realistic property distribution in the model area. In addition, this work also made some key findings:

1. For a specific application of forward stratigraphic modeling in GPM^{TM} and a range of model parameters, the process of sediment deposition is influenced by diffusion rate, and proximity to sediment source. This is consistent with several published works on sequence stacking and or system tracts in shallow marine settings, but further work with different stratigraphic modeling simulators could be useful in mitigating some of the challenges faced in this work.
2. A geologically viable 3-D lithofacies distribution in the shallow marine Hugin formation was achieved, which is evident in scenarios where sediment distribution vertically matches with lithofacies variation in a sampled interval in an actual well log.

Geologically feasible stratigraphic patterns generated in the forward stratigraphic model provide additional confidence in the representation of lithofacies, and therefore porosity and permeability property variations in the depositional setting under study. ~~By reducing the level of property uncertainty between wells, a reliable reservoir model can be generated to guide field planning and development in the hydrocarbon exploration and production industry.~~

~~Future studies will focus on using an artificial neural network approach to classify lithofacies associations in the forward stratigraphic model in an attempt to reduce uncertainties that arise from cognitive or sampling biases in the calculator (or rule based) approach for estimating lithofacies proportion in a forward stratigraphic model. In addition, efforts will be made in a future contribution to compare the stratigraphic property distribution with ones that are generated more classical methods such as sequential indicator simulation (SIS), and object-based modeling.~~The resultant forward stratigraphic-based porosity and permeability model suggests that forward stratigraphic simulation outputs can be integrated into classical modeling workflows to improve subsurface property modeling , and well planning strategies.

Data and Code Availability

The datasets used in this work was obtained from Equinor on their Volve field operations, Norway. This include: 24 suits of well logs, and 3-D reservoir models in Eclipse and RMS formats. The data, models (eclipse and RMS formats), and the rule-based calculation script to generate lithofacies and porosity/permeability proportions are archived on Zenodo as Otoo & Hodgetts, (2020).

GPM^{TM} Software

The version (2019.1) of GPM^{TM} software was used in completing this work after an initial 2018.1 version. Available on: https://www.software.slb.com/products/gpm. The software license and code used in the GPM^{TM} cannot be provided, because Schlumberger does not allow the code for its software to be shared in publications.

Model Availability in Petrel^{TM}

Petrel^{TM} software (2017.1) was initially used for the task, but completed with Petrel^{TM} software (2019.1); available on: https://www.software.slb.com/products/petrel. The software run on a windows PC with the following specifications: Processor; Intel Xeon CPU E5-1620 v3 @3.5GHz 4 cores-8 threads, Memory; 64 GB RAM. The computer should be high end, because a lot of processing time is required to execute a task. The forward stratigraphic models are achieved in Zenodo as Otoo & Hodgetts, (2020).

Author Contribution

Daniel Otoo designed the model workflow, conducted the simulation using the GPM^{TM} software, and evaluated the results. David Hodgetts converted the Volve field data into Petrel compactible format for easy integration with outputs from the stratigraphic simulation.

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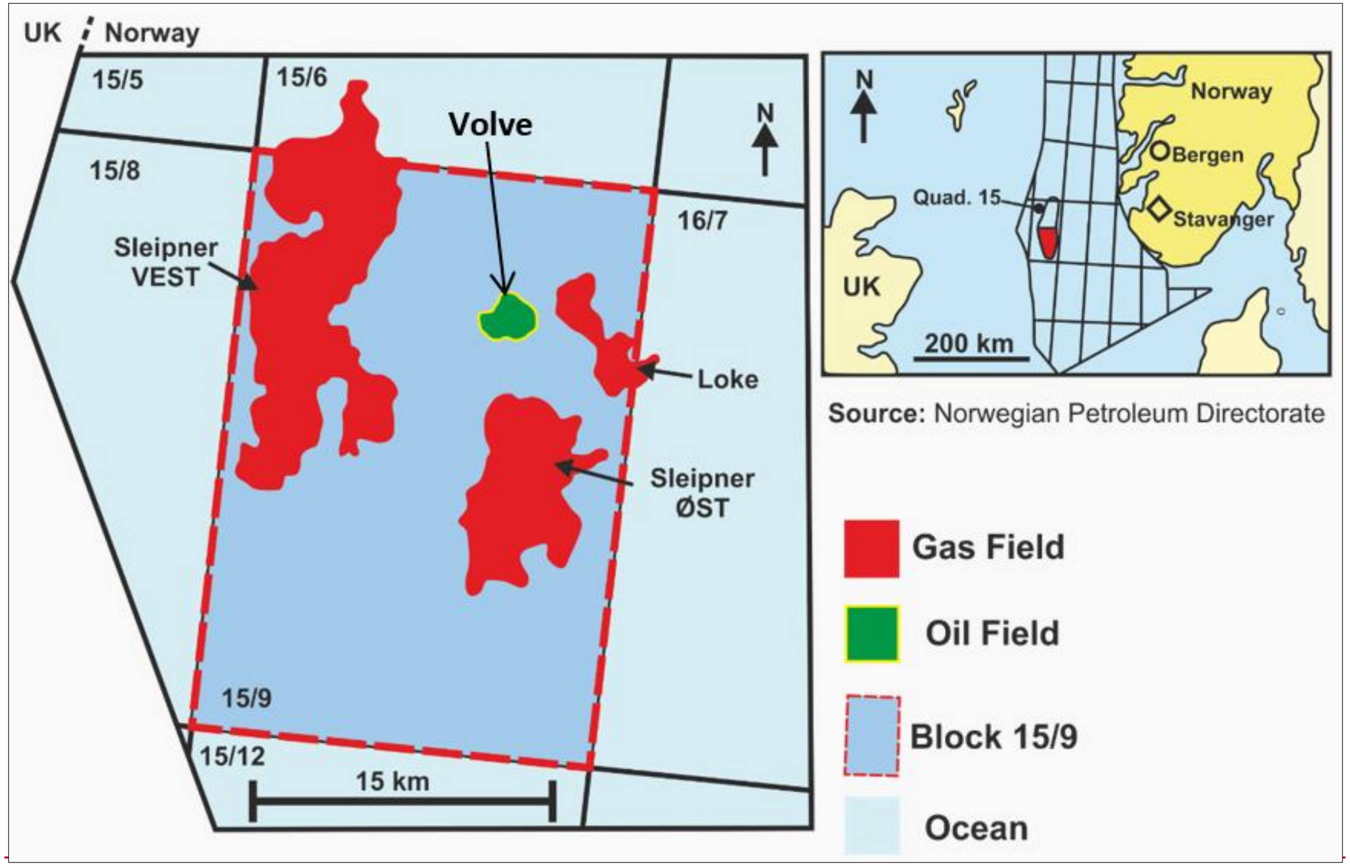
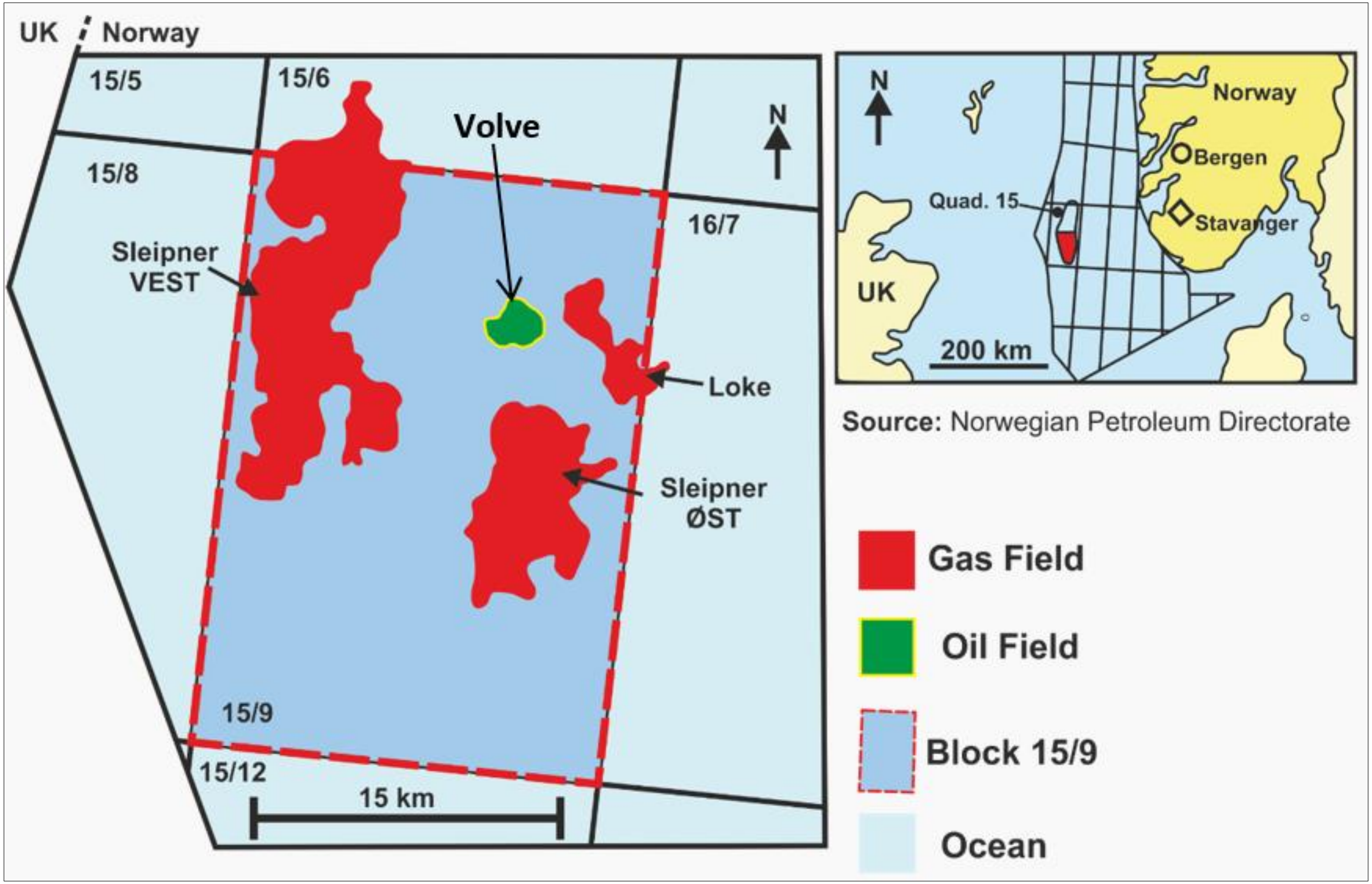
List of Figures

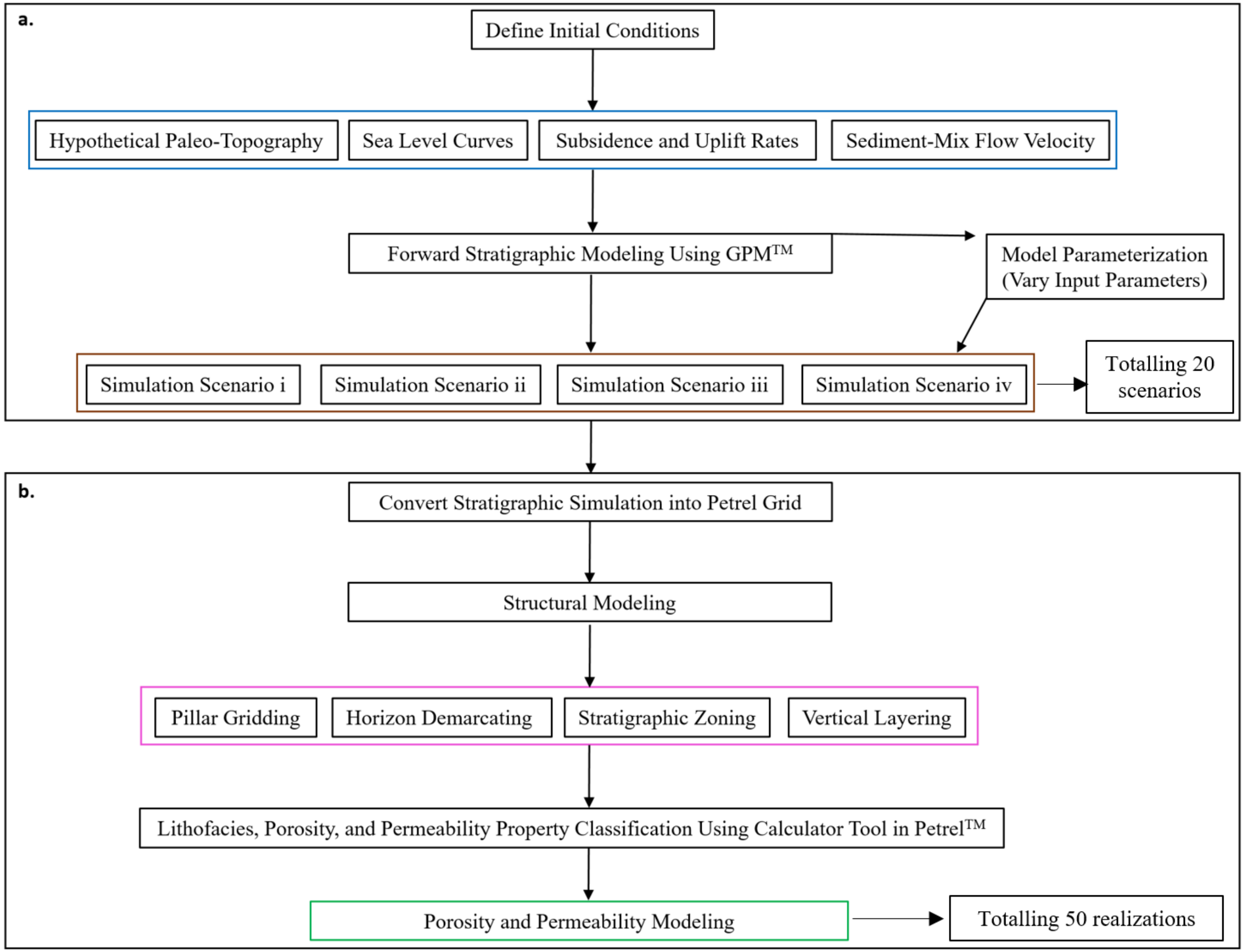


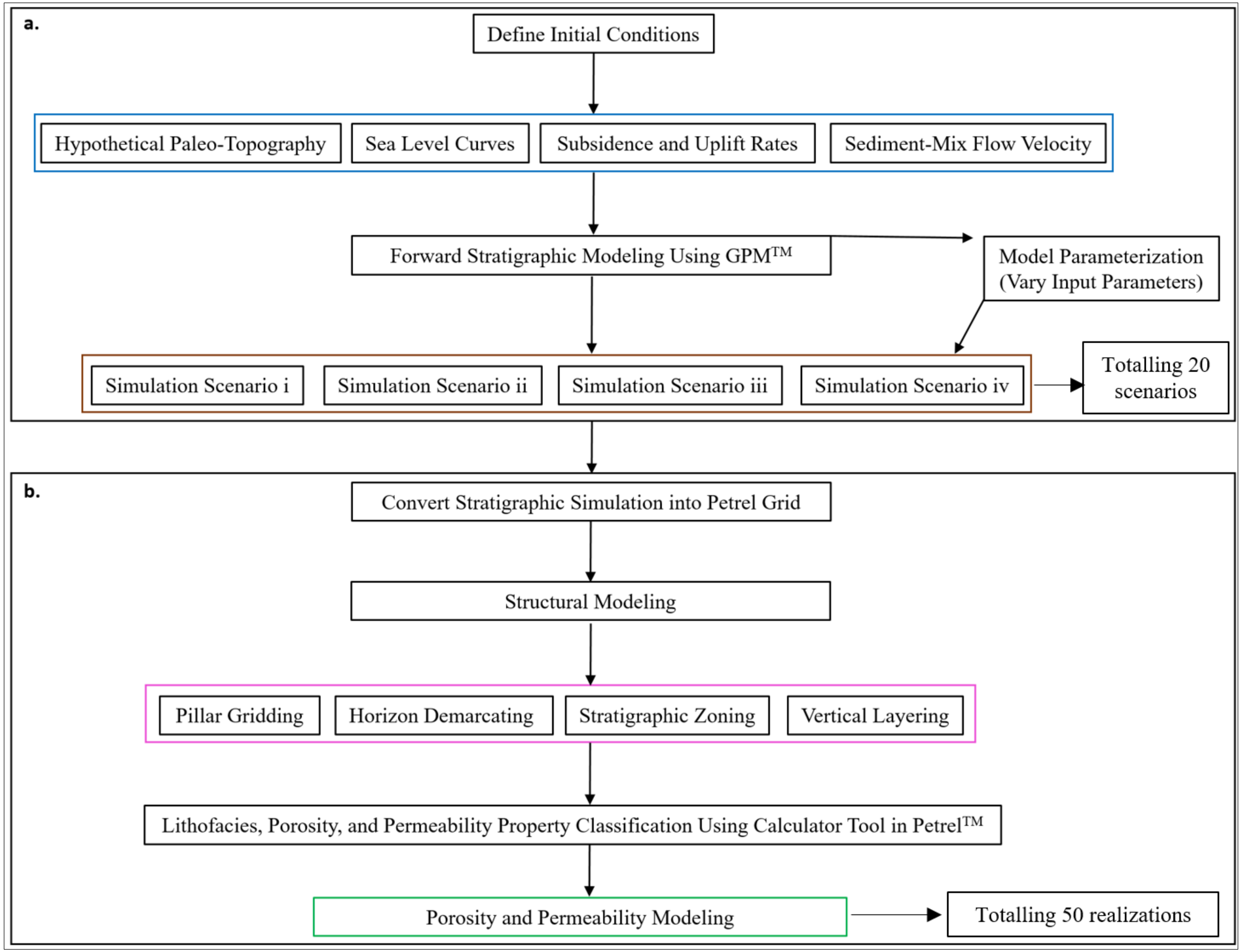
Source: Norwegian Petroleum Directorate



Source: Norwegian Petroleum Directorate

Fig 1. Location map of the Volve field, showing gas and oil fields in quadrant 15/9, Norwegian North Sea (Adapted from Ravasi et al., 2015).


a.
Define Initial Conditions
Hypothetical Paleo-Topography
Sea Level Curves
Subsidence and Uplift Rates
Sediment-Mix Flow Velocity
Forward Stratigraphic Modeling Using GPM™
Model Parameterization (Vary Input Parameters)
Simulation Scenario i
Simulation Scenario ii
Simulation Scenario iii
Simulation Scenario iv
Totalling 20 scenarios
b.
Convert Stratigraphic Simulation into Petrel Grid
Structural Modeling
Pillar Gridding
Horizon Demarcating
Stratigraphic Zoning
Vertical Layering
Lithofacies, Porosity, and Permeability Property Classification Using Calculator Tool in Petrel™
Porosity and Permeability Modeling
Totalling 50 realizations


a.
Define Initial Conditions
Hypothetical Paleo-Topography
Sea Level Curves
Subsidence and Uplift Rates
Sediment-Mix Flow Velocity
Forward Stratigraphic Modeling Using GPM™
Model Parameterization (Vary Input Parameters)
Simulation Scenario i
Simulation Scenario ii
Simulation Scenario iii
Simulation Scenario iv
Totalling 20 scenarios
b.
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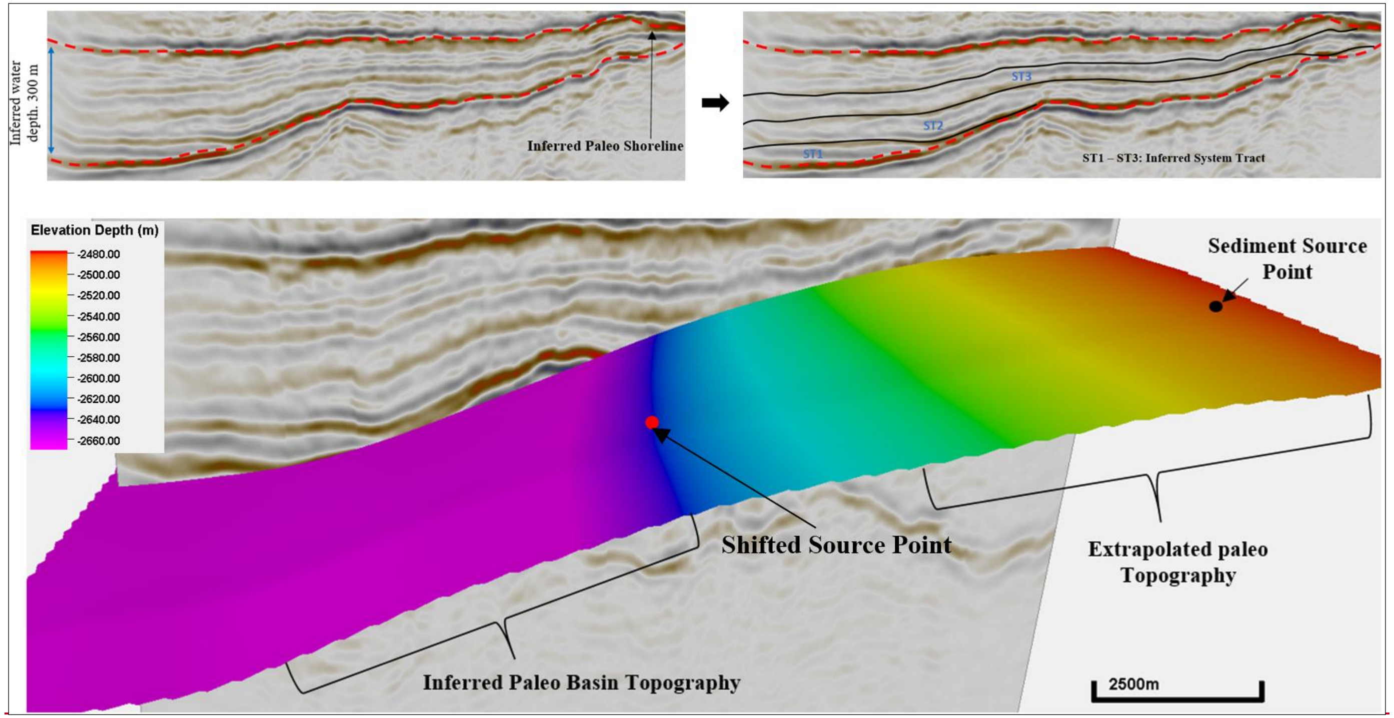
Horizon Demarcating
Stratigraphic Zoning
Vertical Layering
Lithofacies, Porosity, and Permeability Property Classification Using Calculator Tool in Petrel™
Porosity and Permeability Modeling
Totalling 50 realizations

Fig 2. Schematic workflow of processes involved this work. a. providing information of initial conditions (or input parameters) that were used in the forward stratigraphic simulation in GPM^{TM}, b. demonstrating how the forward stratigraphic were converted into a grid that is usable in ~~the~~ Petrel^{TM} ~~environment~~ for ~~onward 3-D~~ porosity and permeability modeling.


Inferred water depth. 300 m
Inferred Paleo Shoreline
ST3
ST2
ST1
ST1 – ST3: Inferred System Tract
Elevation Depth (m)
-2480.00
-2500.00
-2520.00
-2540.00
-2560.00
-2580.00
-2600.00
-2620.00
-2640.00
-2660.00
Sediment Source Point
Shifted Source Point
Extrapolated paleo Topography
Inferred Paleo Basin Topography
2500m

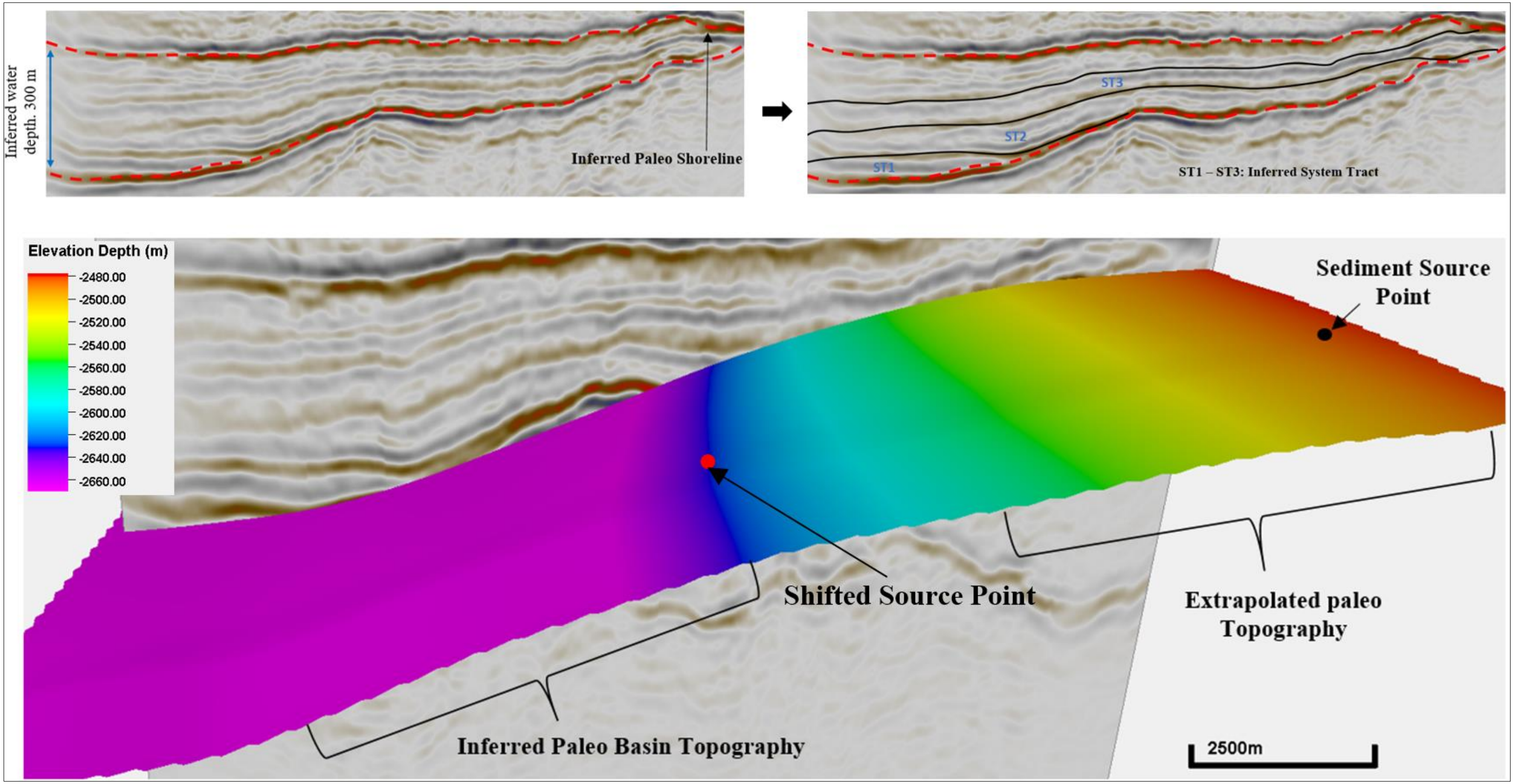
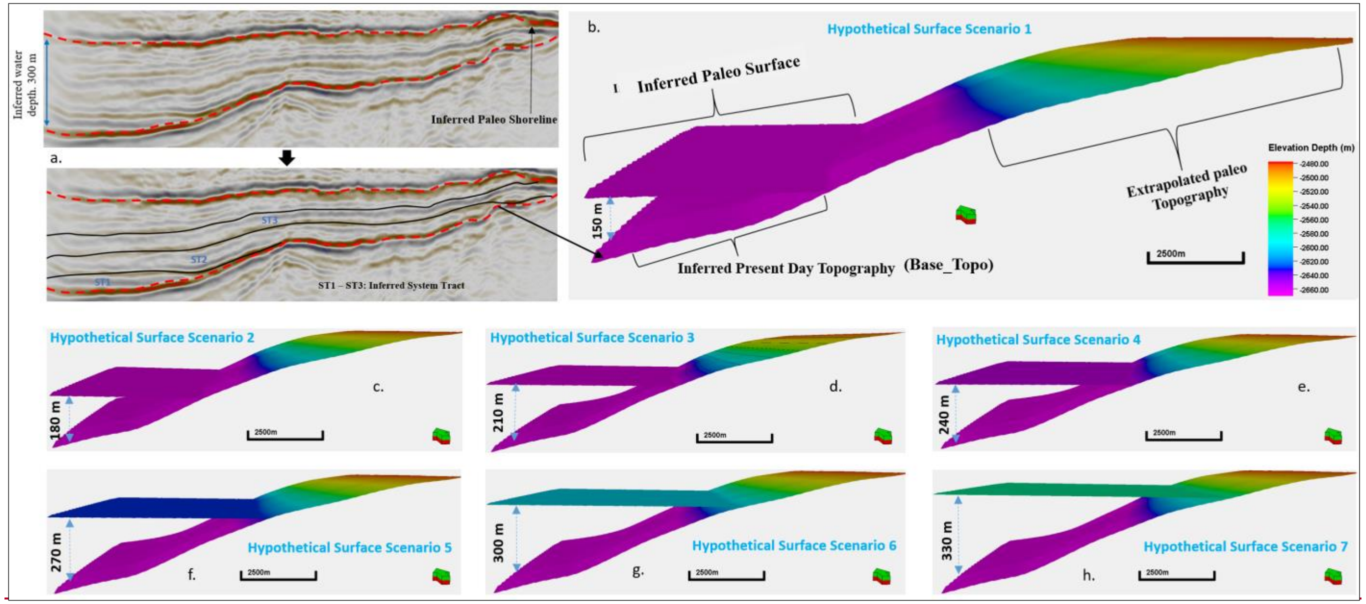


Fig 3. 3-D seismic section of the study area, from which the hypothetical topographic surface was derived for the simulation. The sedimentary entry point into the basin is located in the North Eastern section, based on previous study in the model area (e.g. Kieft et al. 2011).


a.
Inferred water depth. 300 m
Inferred Paleo Shoreline
ST3
ST2
ST1
ST1 – ST3: Inferred System Tract
b.
Hypothetical Surface Scenario 1
Inferred Paleo Surface
150 m
Inferred Present Day Topography (Base_Topo)
Extrapolated paleo Topography
Elevation Depth (m)
-2480.00
-2500.00
-2520.00
-2540.00
-2560.00
-2580.00
-2600.00
-2620.00
-2640.00
-2660.00
2500m
Hypothetical Surface Scenario 2
c.
180 m
2500m
Hypothetical Surface Scenario 3
d.
210 m
2500m
Hypothetical Surface Scenario 4
e.
240 m
2500m
Hypothetical Surface Scenario 5
f.
270 m
2500m
Hypothetical Surface Scenario 6
g.
300 m
2500m
Hypothetical Surface Scenario 7
h.
330 m
2500m

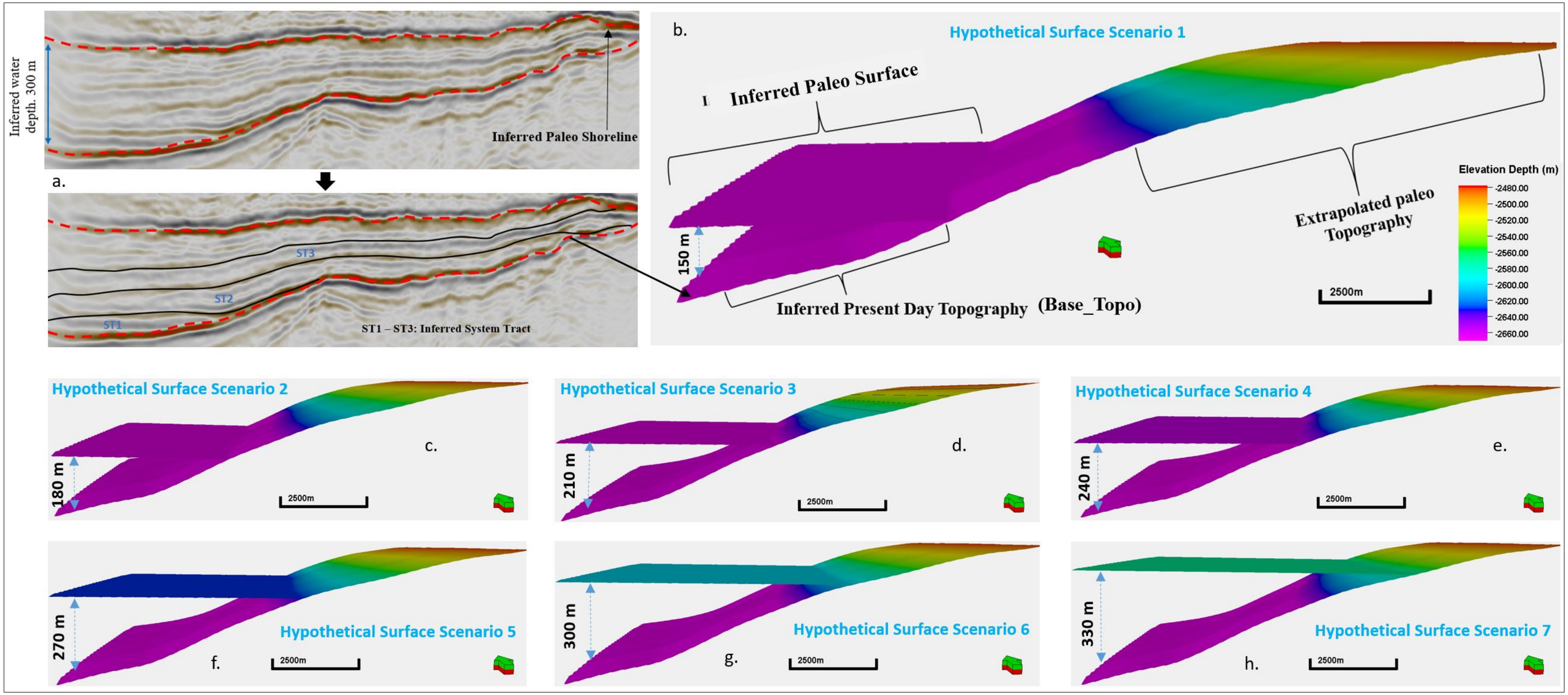
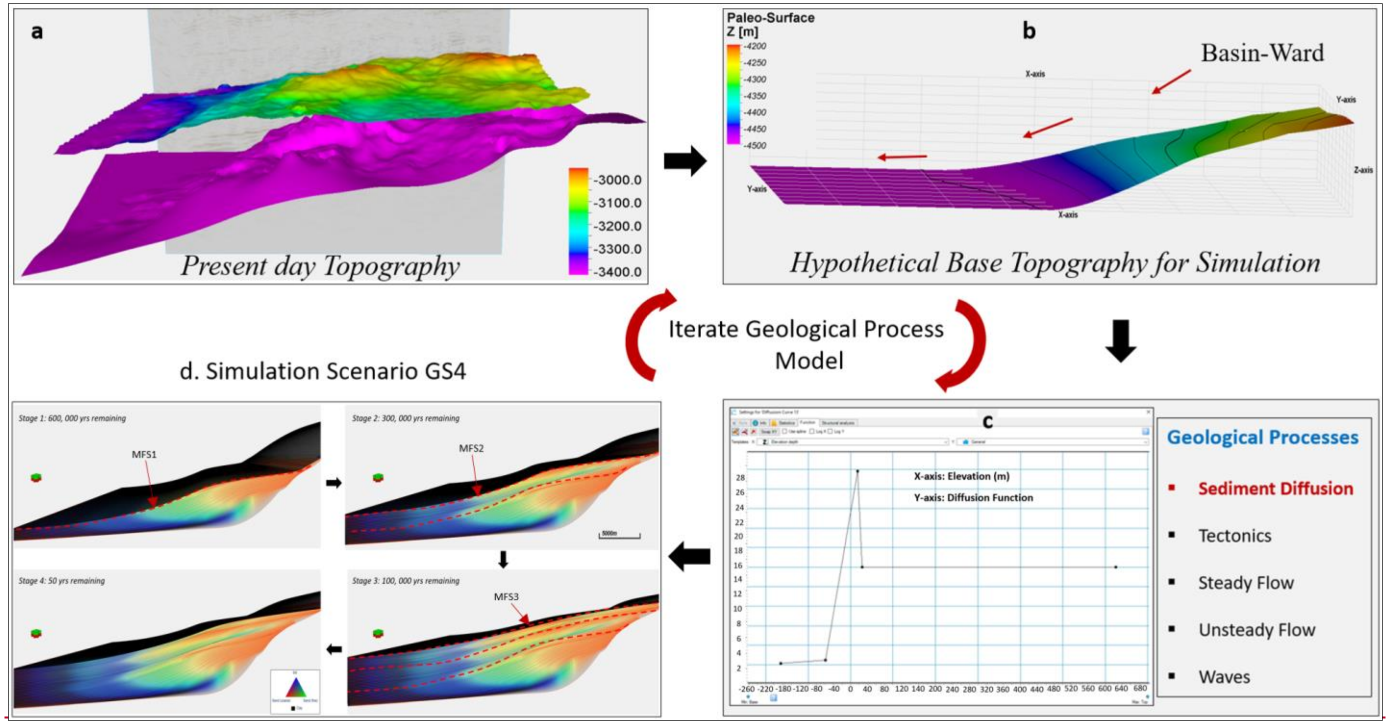


Fig 4. Inferred paleo topographic surface from seismic, also illustrating different topographic surface scenarios used in the simulation.


a
-3000.0
-3100.0
-3200.0
-3300.0
-3400.0
Present day Topography
Paleo-Surface
Z [m]
-4200
-4250
-4300
-4350
-4400
-4450
-4500
b
Basin-Ward
X-axis
Y-axis
Z-axis
Hypothetical Base Topography for Simulation
Iterate Geological Process Model
d. Simulation Scenario GS4
Stage 1: 600, 000 yrs remaining
MFS1
Stage 2: 300, 000 yrs remaining
MFS2
5000m
Stage 4: 50 yrs remaining
Stage 3: 100, 000 yrs remaining
MFS3
c
X-axis: Elevation (m)
Y-axis: Diffusion Function
28
26
24
22
20
18
16
14
12
10
8
6
4
2
-260 -220 -180 -120 -80 -40 0 40 80 120 140 200 240 280 320 360 400 440 480 520 560 600 640 680
Geological Processes
Sediment Diffusion
Tectonics
Steady Flow
Unsteady Flow
Waves

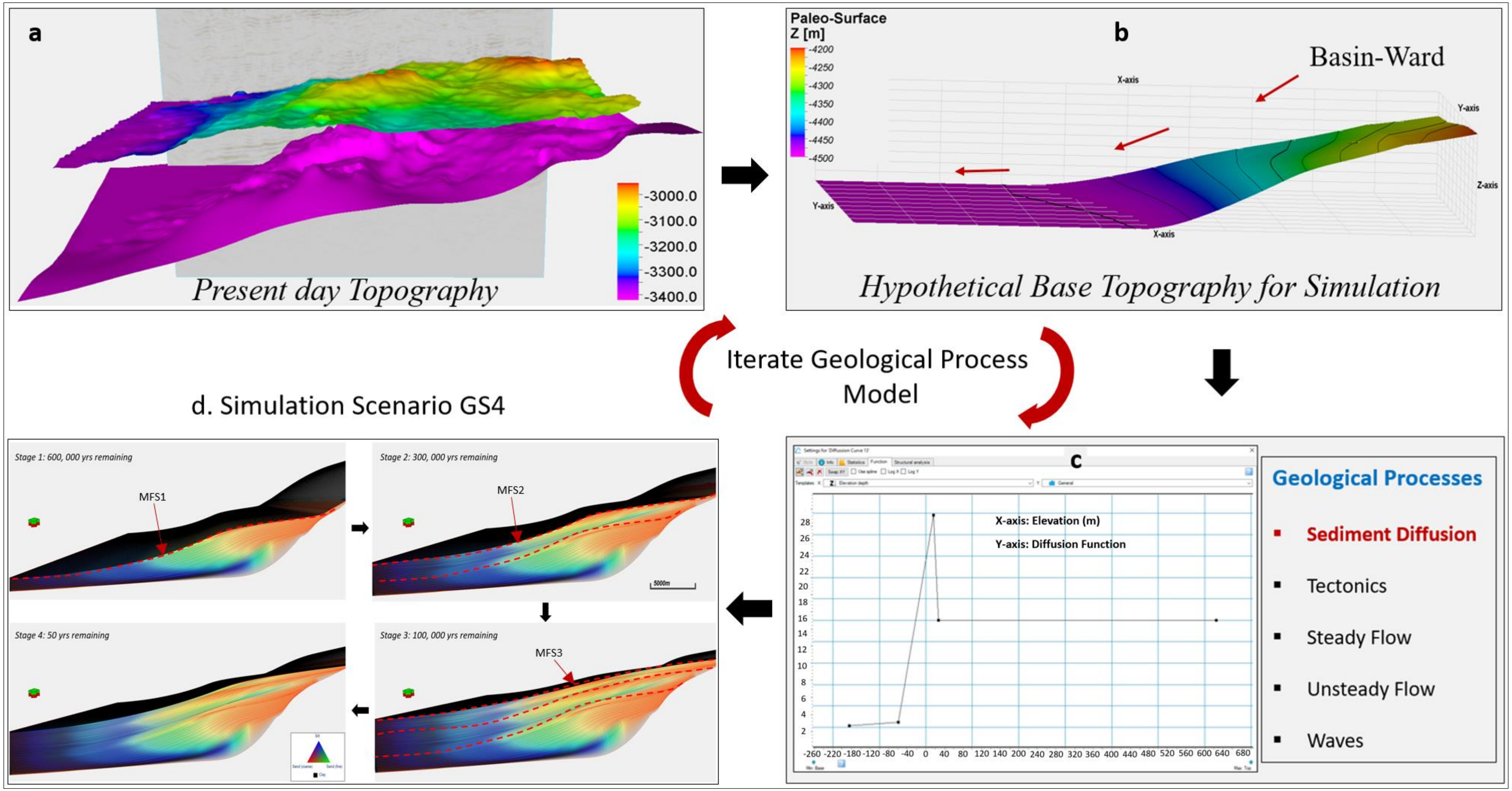


Fig 5. a. present day top and bottom topographic surfaces of the Hugin formation; b. hypothetical topographic surface derived from seismic data; c. geological processes involved in the simulation; d. forward stratigraphic models at different simulation time.

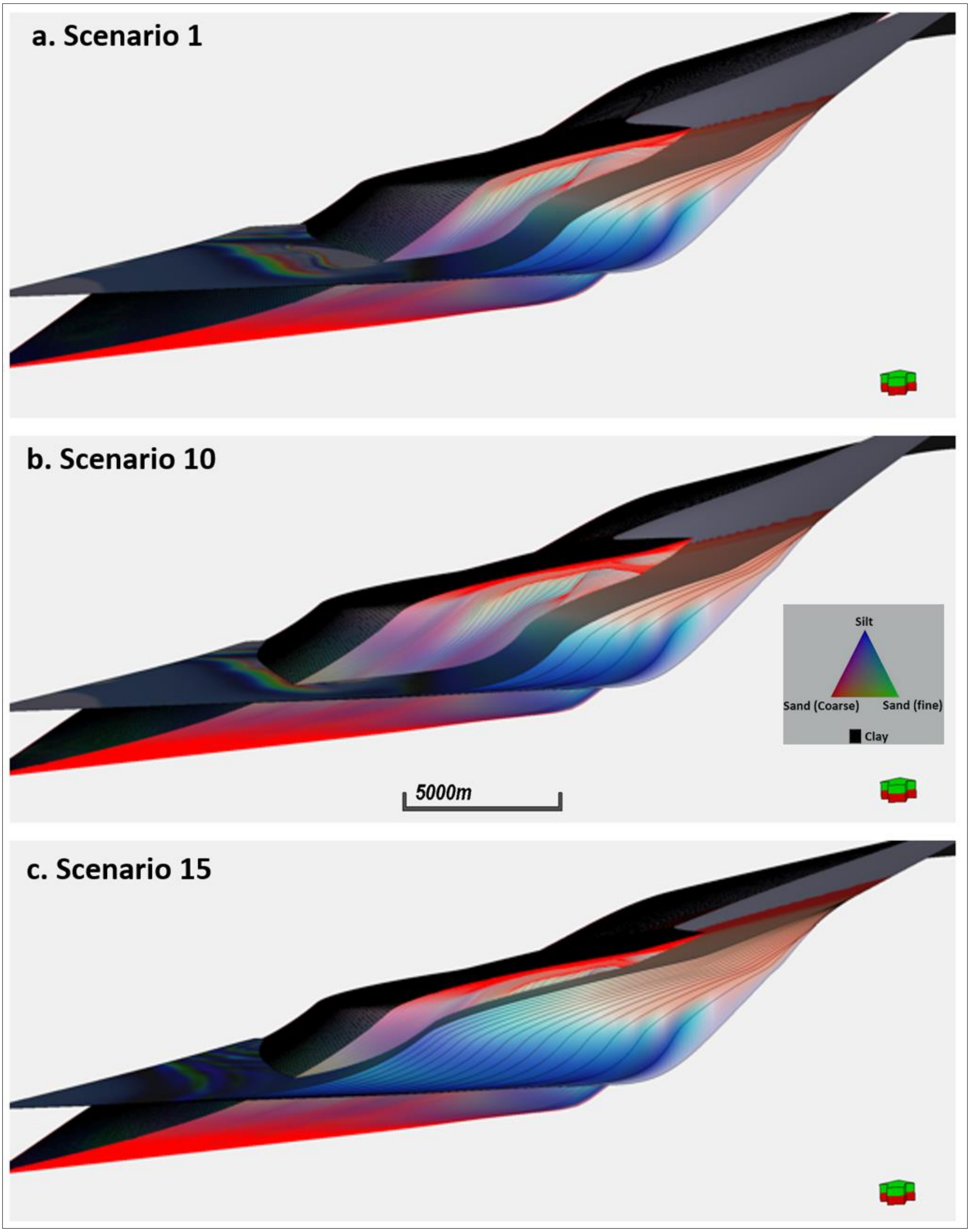
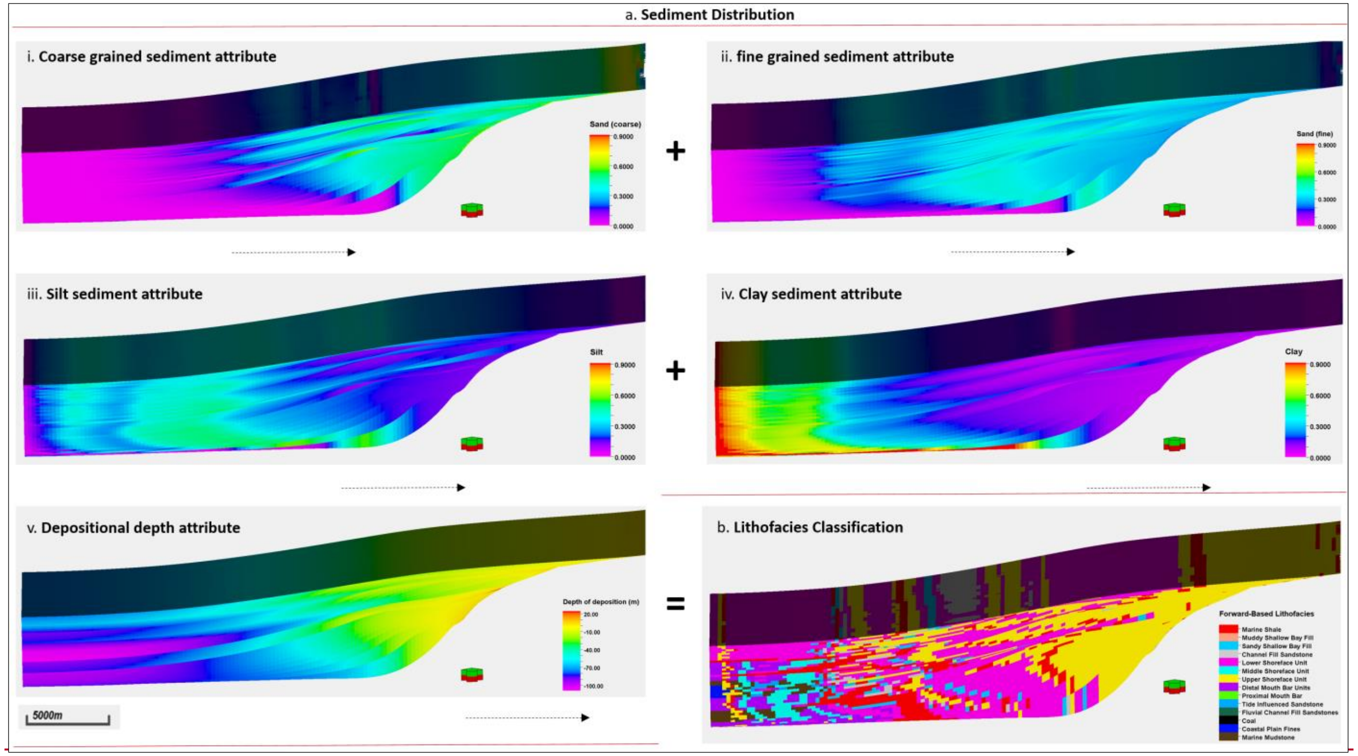


Fig 6. Stratigraphic simulation scenarios depicting sediment deposition in a shallow marine framework. **a.** scenario 1 involves equal proportions of sediment input, a relatively low subsidence rate and low water depth, **b.** scenario 10 uses high proportions of fine sand and silt (i.e. 70%) in the sediment mix, abrupt changes in subsidence rate, and a relatively high water depth, c. scenario 15 involves very high proportions of fine sand and silt (i.e. 80%), steady rate of subsidence and uplift in the sediment source area, and a relatively low water depth.


a. Sediment Distribution
i. Coarse grained sediment attribute
Sand (coarse)
0.9000
0.6000
0.3000
0.0000
+
ii. fine grained sediment attribute
Sand (fine)
0.9000
0.6000
0.3000
0.0000
iii. Silt sediment attribute
Silt
0.9000
0.6000
0.3000
0.0000
+
iv. Clay sediment attribute
Clay
0.9000
0.6000
0.3000
0.0000
v. Depositional depth attribute
Depth of deposition (m)
20.00
-10.00
-40.00
-70.00
-100.00
=
5000m
b. Lithofacies Classification
Forward-Based Lithofacies
Marine Shale
Muddy Shallow Bay Fill
Sandy Shallow Bay Fill
Channel Fill Sandstone
Lower Shoreface Unit
Middle Shoreface Unit
Upper Shoreface Unit
Distal Mouth Bar Units
Proximal Mouth Bar
Tide Influenced Sandstone
Fluvial Channel Fill Sandstones
Coal
Coastal Plain Fines
Marine Mudstone

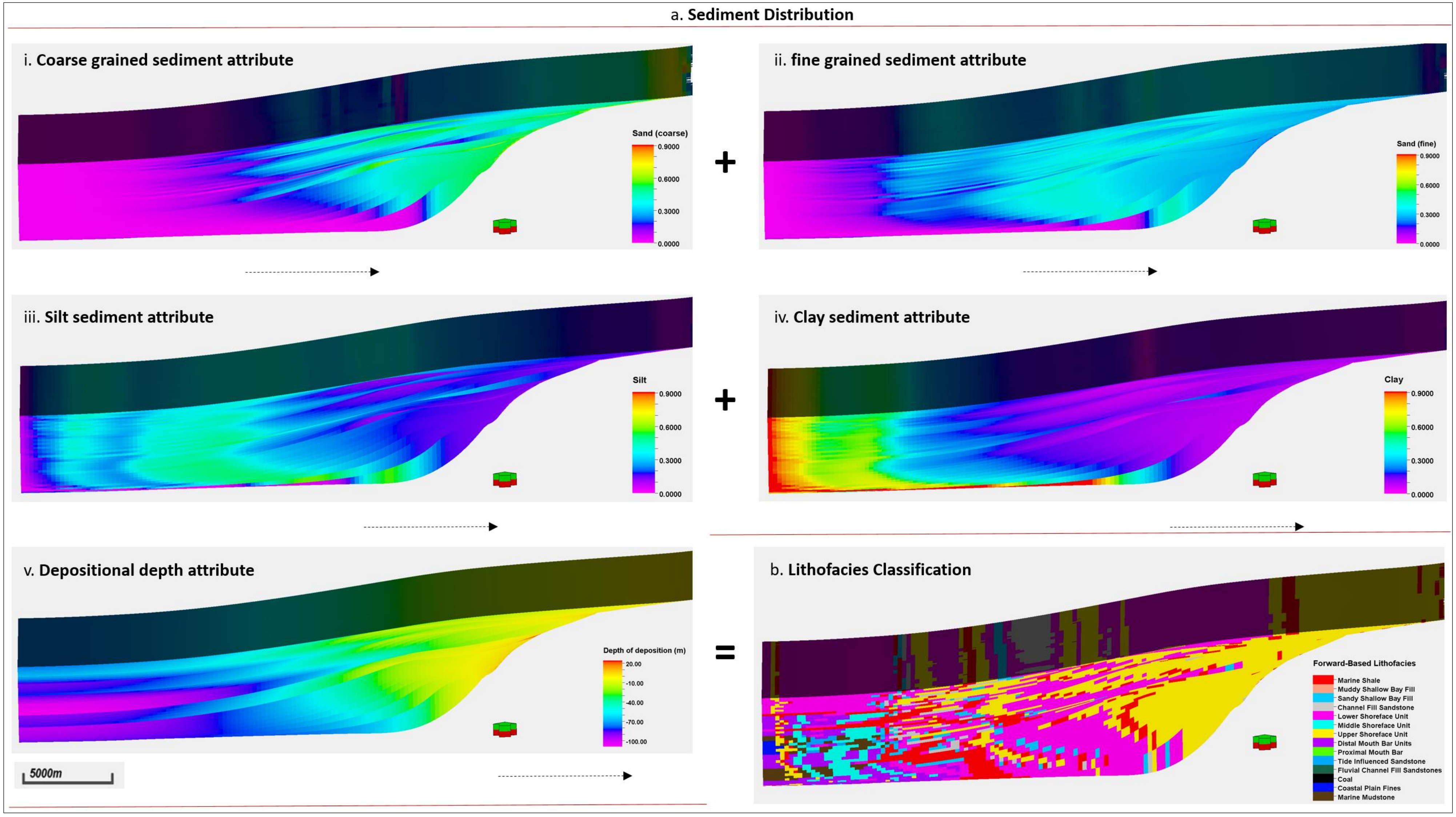


Fig 7 a. Sediment distribution patterns in the geological process modeling software. b. lithofacies classification using the property calculator tool in Petrel^{TM}.

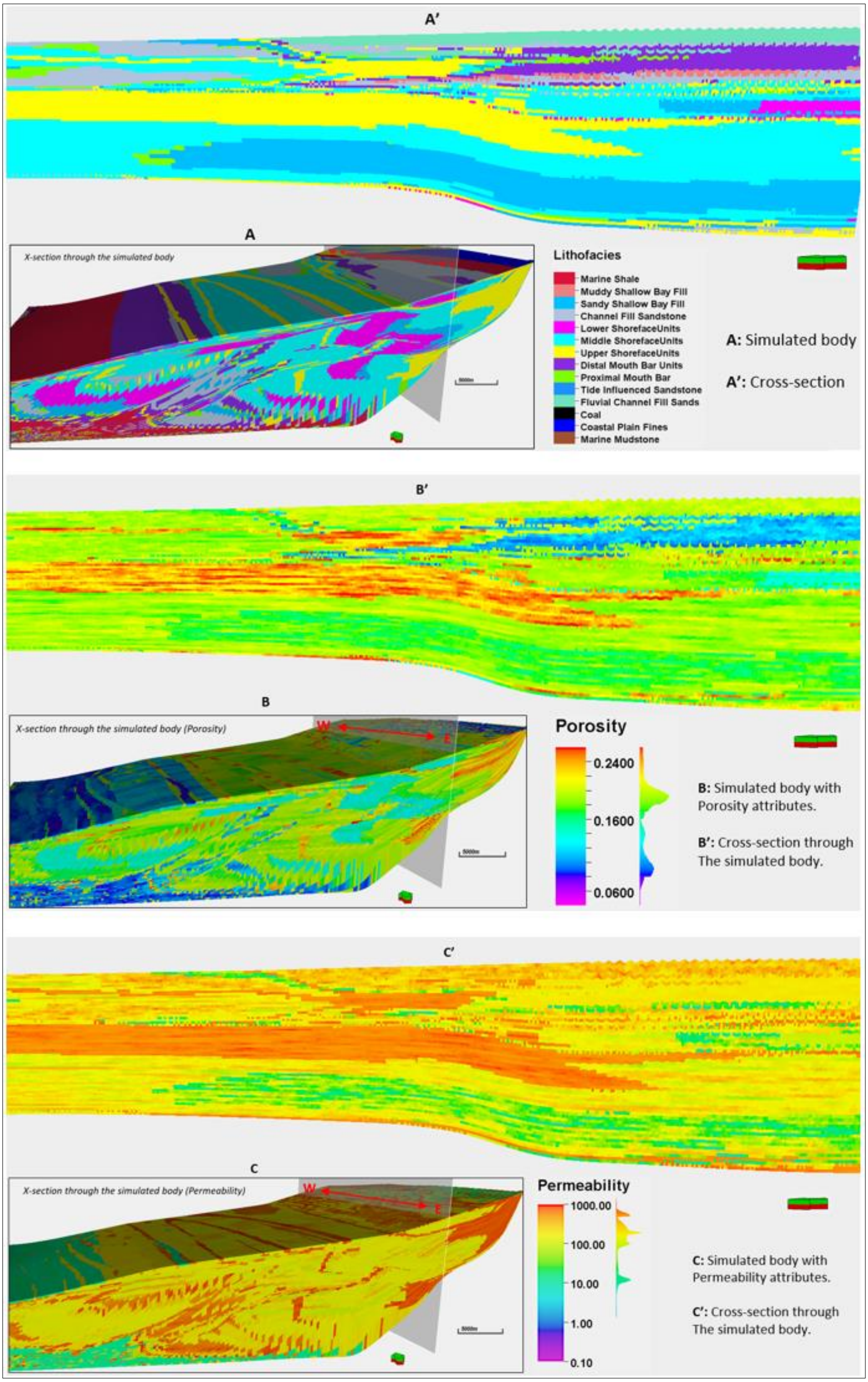
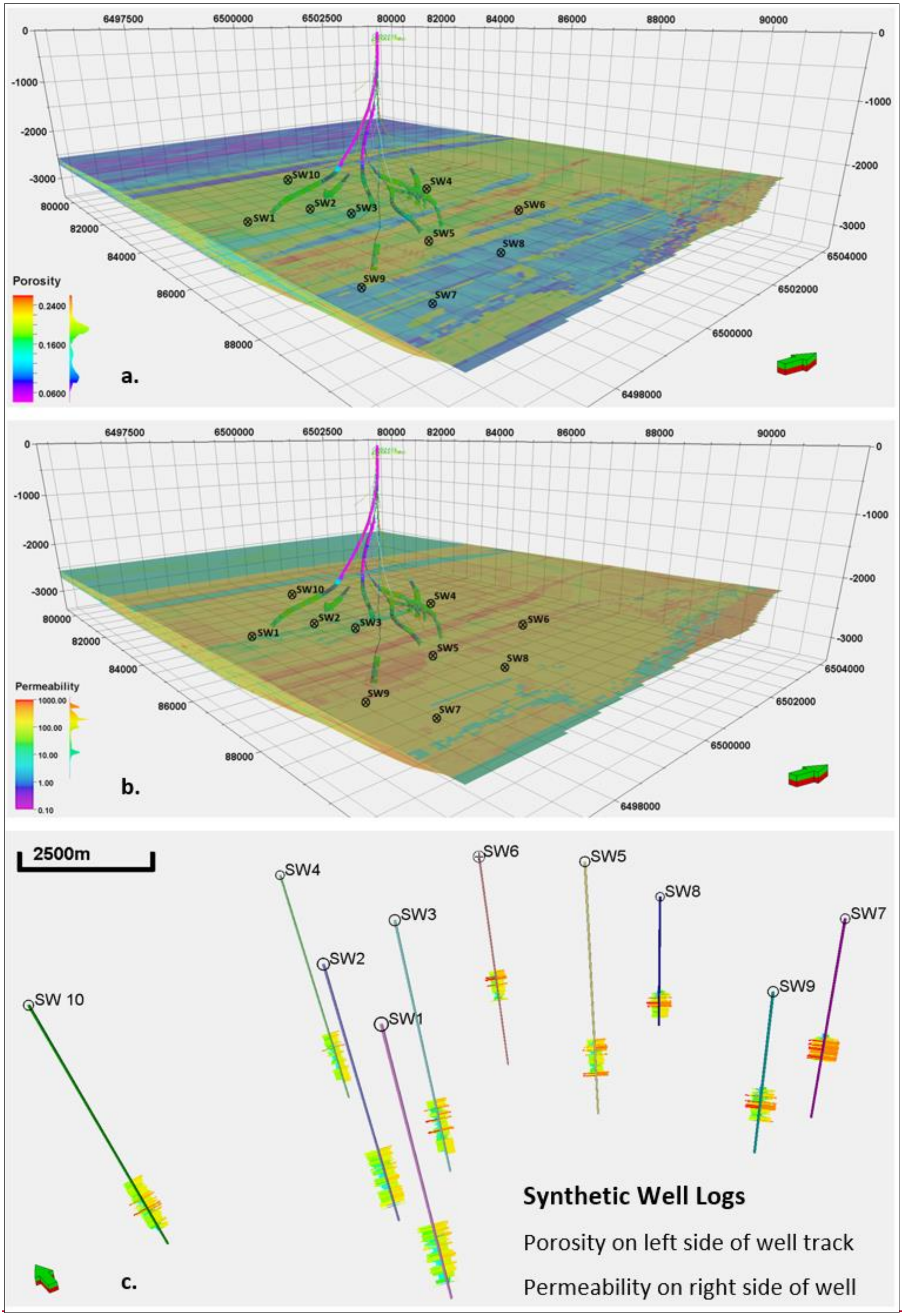

A'
A
X-section through the simulated body
Lithofacies
Marine Shale
Muddy Shallow Bay Fill
Sandy Shallow Bay Fill
Channel Fill Sandstone
Lower ShorefaceUnits
Middle ShorefaceUnits
Upper ShorefaceUnits
Distal Mouth Bar Units
Proximal Mouth Bar
Tide Influenced Sandstone
Fluvial Channel Fill Sands
Coal
Coastal Plain Fines
Marine Mudstone
A: Simulated body
A': Cross-section
B'
B
X-section through the simulated body (Porosity)
W
E
Porosity
0.2400
0.1600
0.0600
B: Simulated body with Porosity attributes.
B': Cross-section through The simulated body.
C'
C
X-section through the simulated body (Permeability)
W
E
Permeability
1000.00
100.00
10.00
1.00
0.10
C: Simulated body with Permeability attributes.
C': Cross-section through The simulated body.

Fig 8. Property characterization in the stratigraphic using the property calculator tool in Petrel. Also showing a cross-sectional view through the model.


a.
Porosity
0.2400
0.1600
0.0600
b.
Permeability
1000.00
100.00
10.00
1.00
0.10
SW1
SW2
SW3
SW4
SW5
SW6
SW7
SW8
SW9
SW10
6497500
6500000
6502500
80000
82000
84000
86000
88000
90000
0
-1000
-2000
-3000
6504000
6502000
6500000
6498000
c.
2500m
SW 10
Synthetic Well Logs
Porosity on left side of well track
Permeability on right side of well

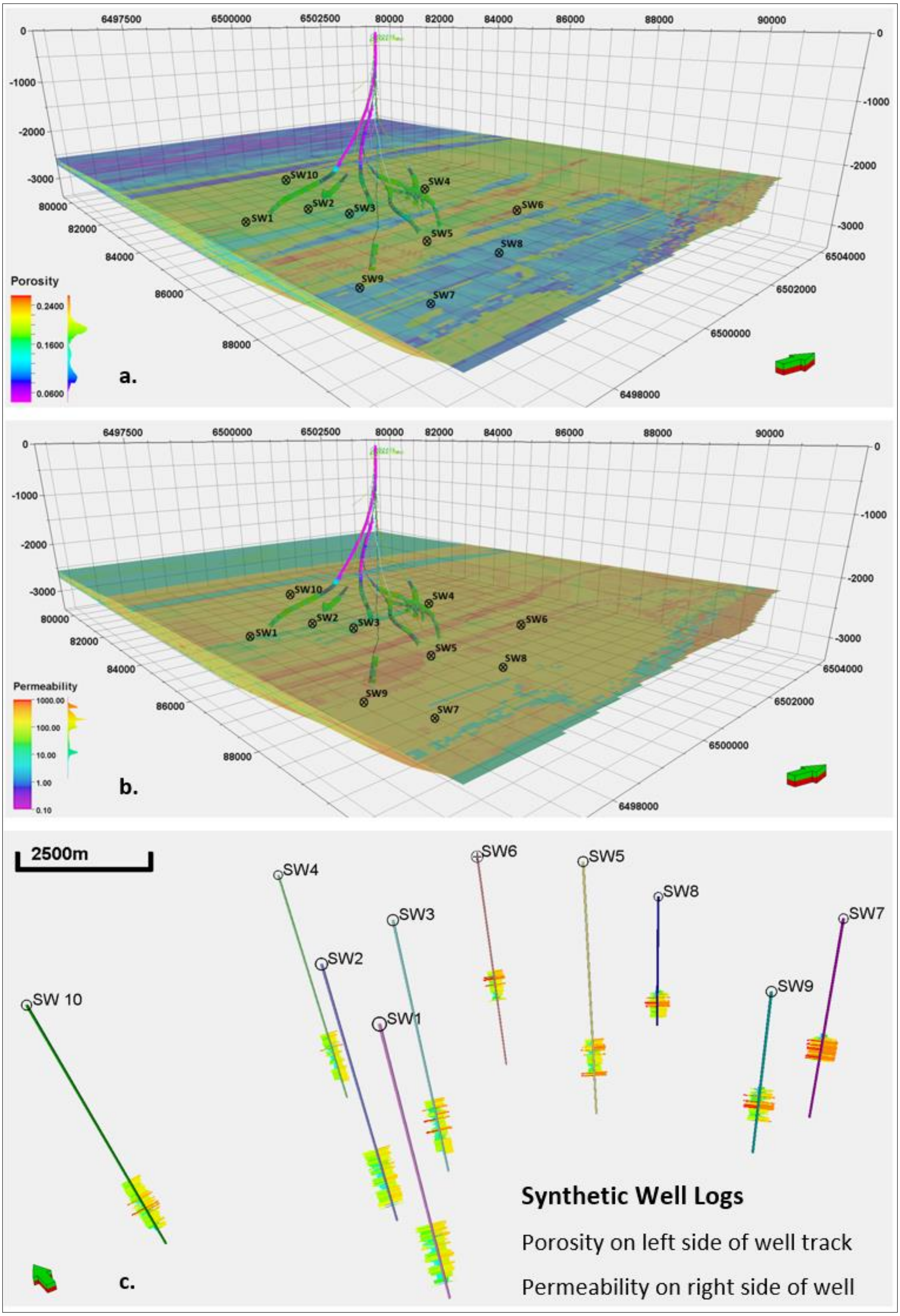
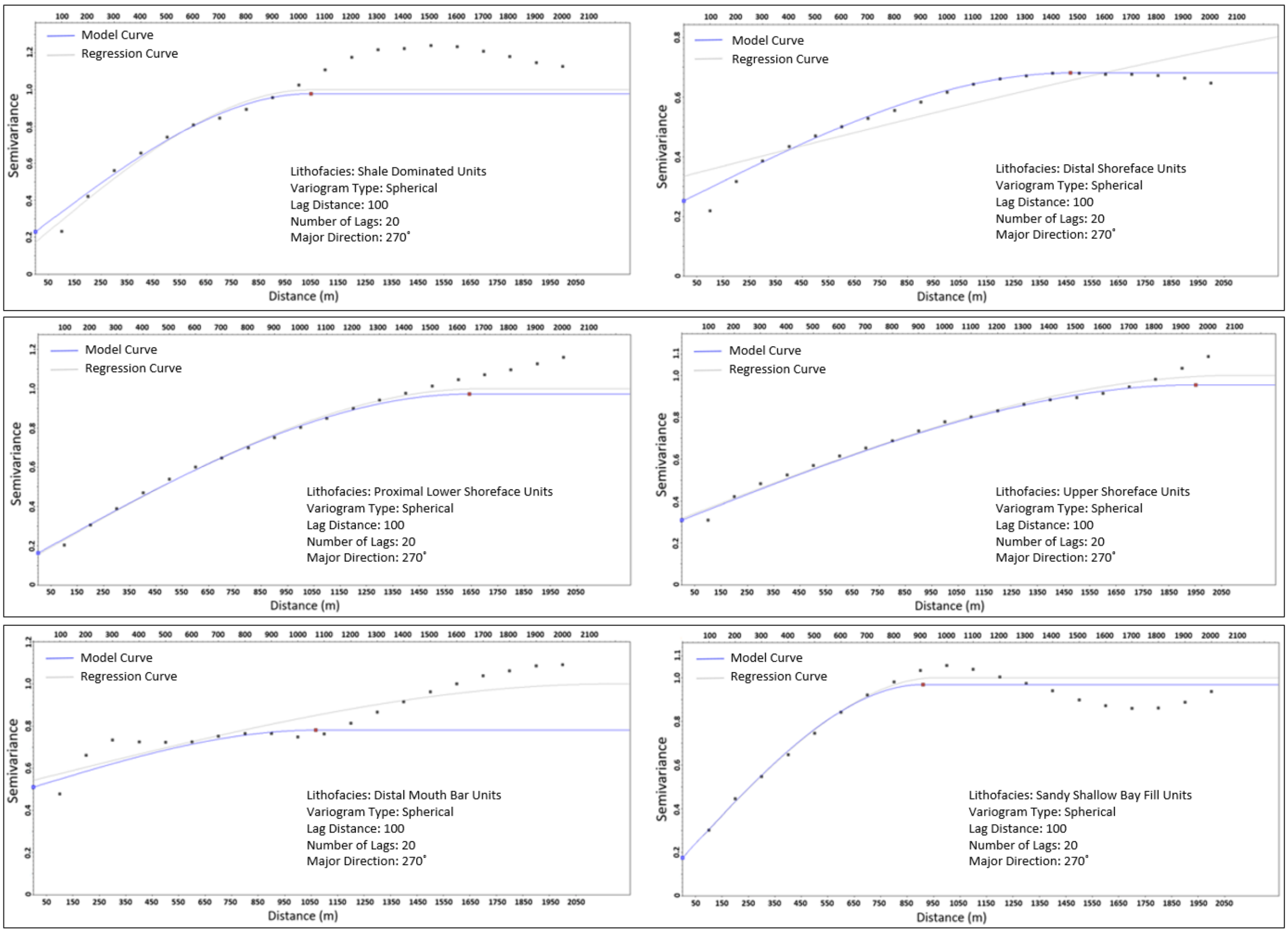
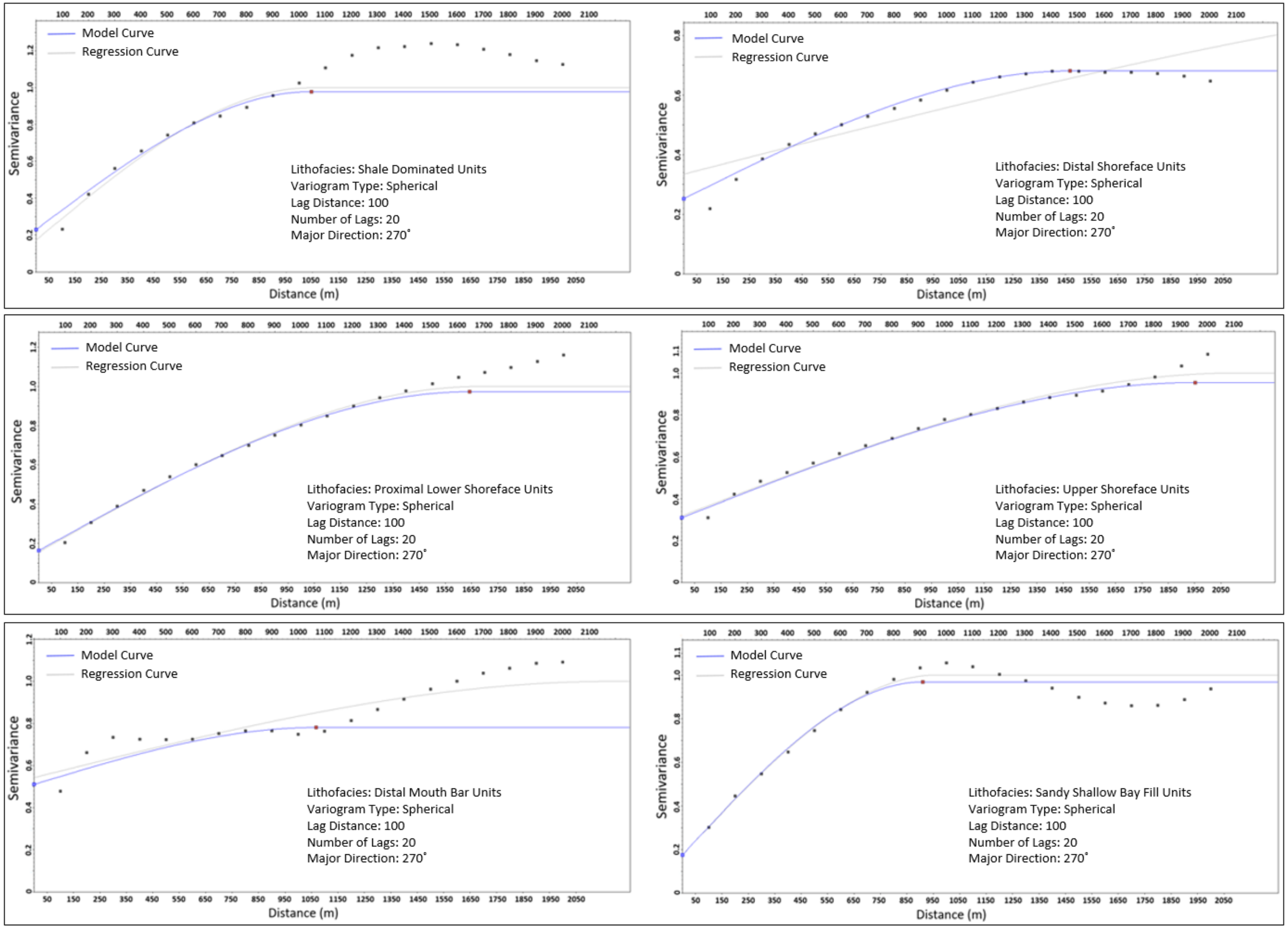


Fig 9. Synthetic wells derived from a forward stratigraphic-driven porosity and permeability models.



The average distance between the synthetic wells shown in Figure 9c is about 0.9 km apart (maximum and minimum separation distance of 1.3 km and 0.65 km respectively).



Lithofacies: Shale Dominated Units
Variogram Type: Spherical
Lag Distance: 100
Number of Lags: 20
Major Direction: 270˚

Lithofacies: Distal Shoreface Units
Variogram Type: Spherical
Lag Distance: 100
Number of Lags: 20
Major Direction: 270˚

Lithofacies: Proximal Lower Shoreface Units
Variogram Type: Spherical
Lag Distance: 100
Number of Lags: 20
Major Direction: 270˚

Lithofacies: Upper Shoreface Units
Variogram Type: Spherical
Lag Distance: 100
Number of Lags: 20
Major Direction: 270˚

Lithofacies: Distal Mouth Bar Units
Variogram Type: Spherical
Lag Distance: 100
Number of Lags: 20
Major Direction: 270˚

Lithofacies: Sandy Shallow Bay Fill Units
Variogram Type: Spherical
Lag Distance: 100
Number of Lags: 20
Major Direction: 270˚

Fig 10. Variogram model of dominant lithofacies units extracted from the FSM. The points indicate the number of lags in the variogram. The distance between these lags is about 100 m. This figure shows the lags between sample pairs for calculating the variogram in the major direction (NE-SW) of the stratigraphic model.

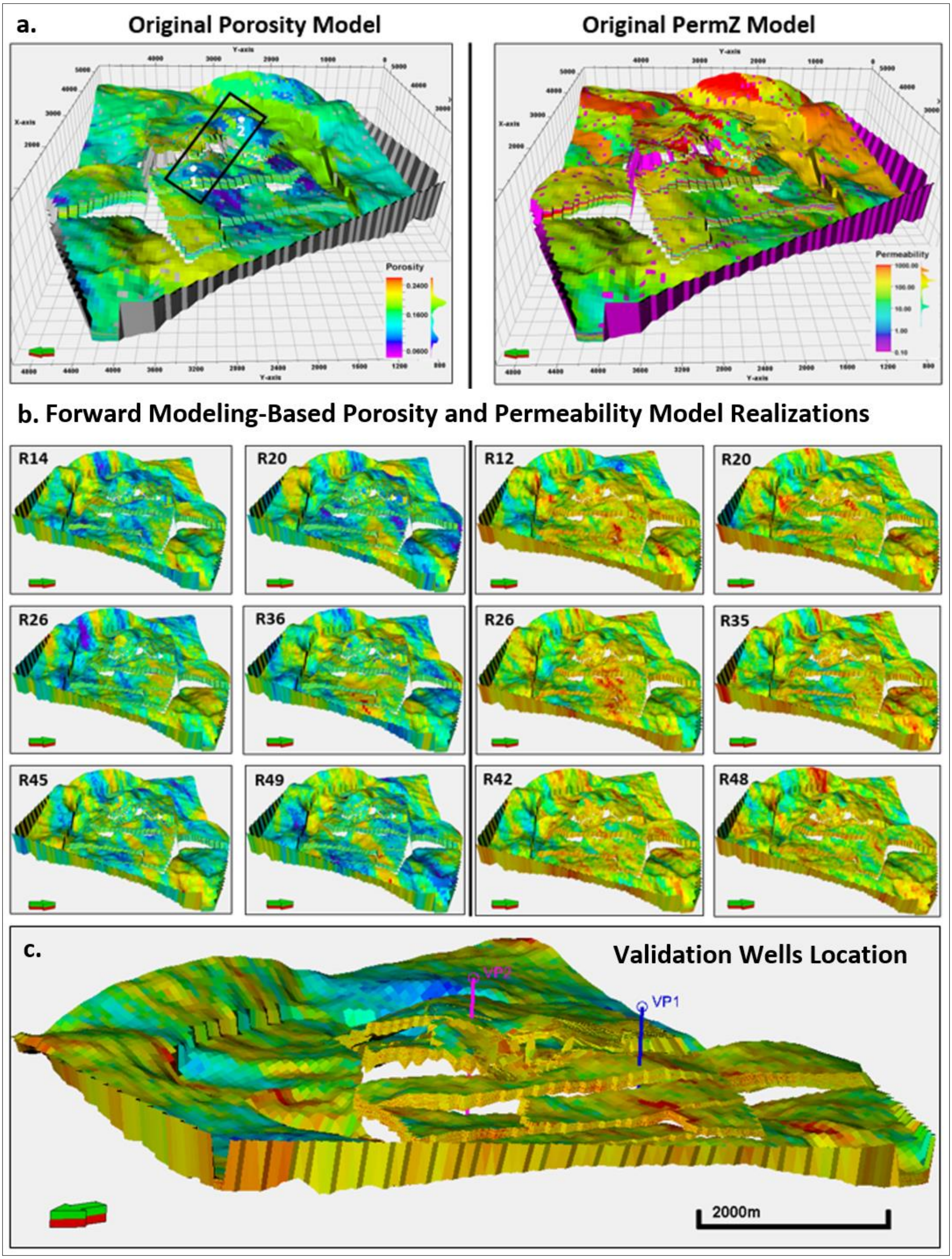
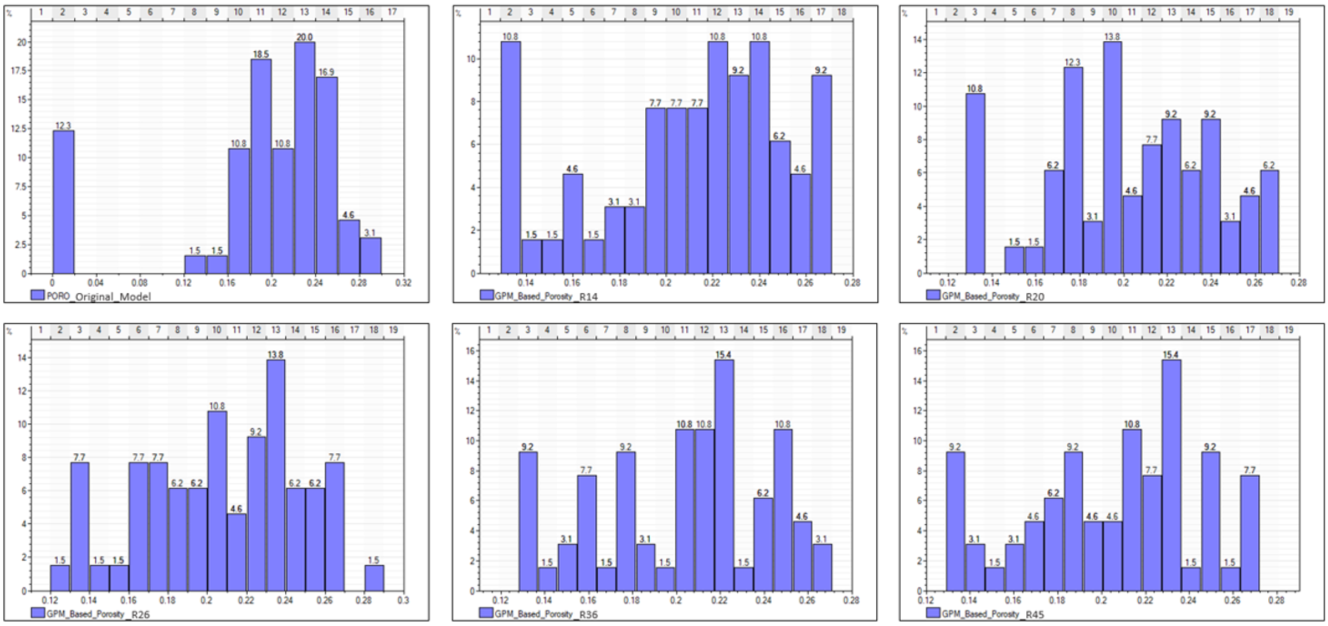
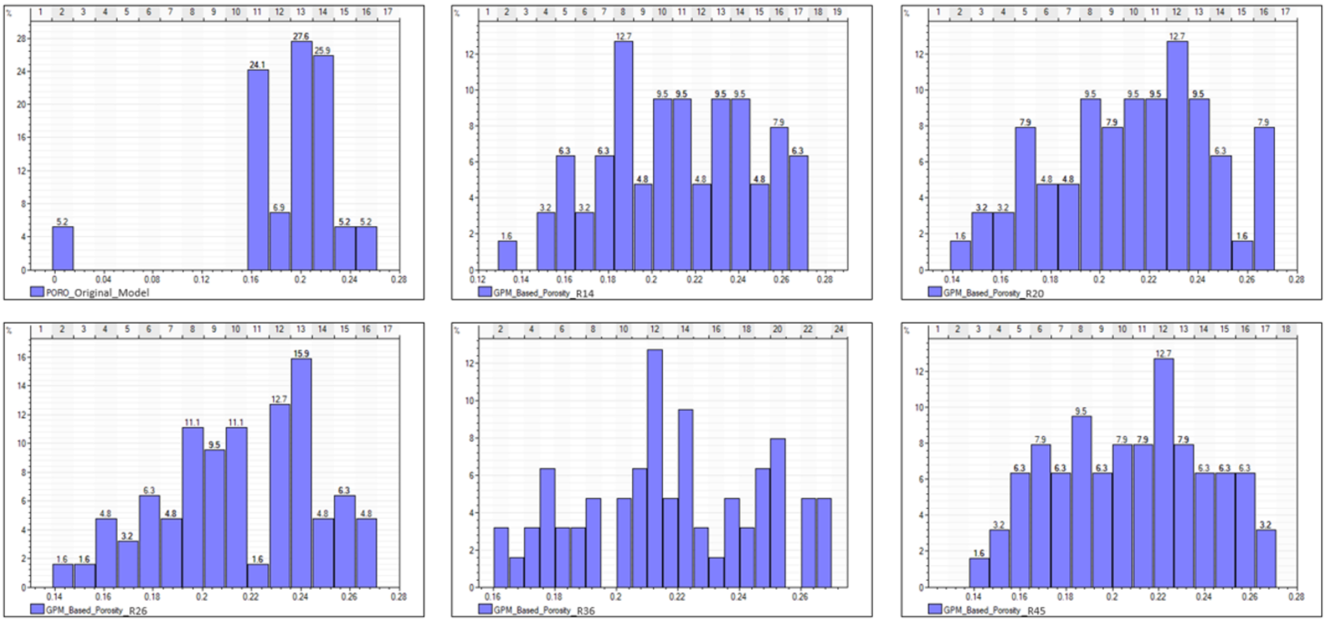

a.
Original Porosity Model
Original PermZ Model
Y-axis
X-axis
1
2
Porosity
0.2400
0.1600
0.0600
Permeability
1000.00
100.00
10.00
1.00
0.10
b. Forward Modeling-Based Porosity and Permeability Model Realizations
R14
R20
R12
R20
R26
R36
R26
R35
R45
R49
R42
R48
c.
Validation Wells Location
VP2
VP1
2000m

Fig 11. Comparing original Volve field model to the forward modeling-based models. Realizations 16, 20, 26, 36, 45, and 49 on the left half are porosity models, whilst realizations 12, 20, 26, 35, 42, and 48 on the right half show permeability models.

a. Validation Well 1



b. Validation Well 2



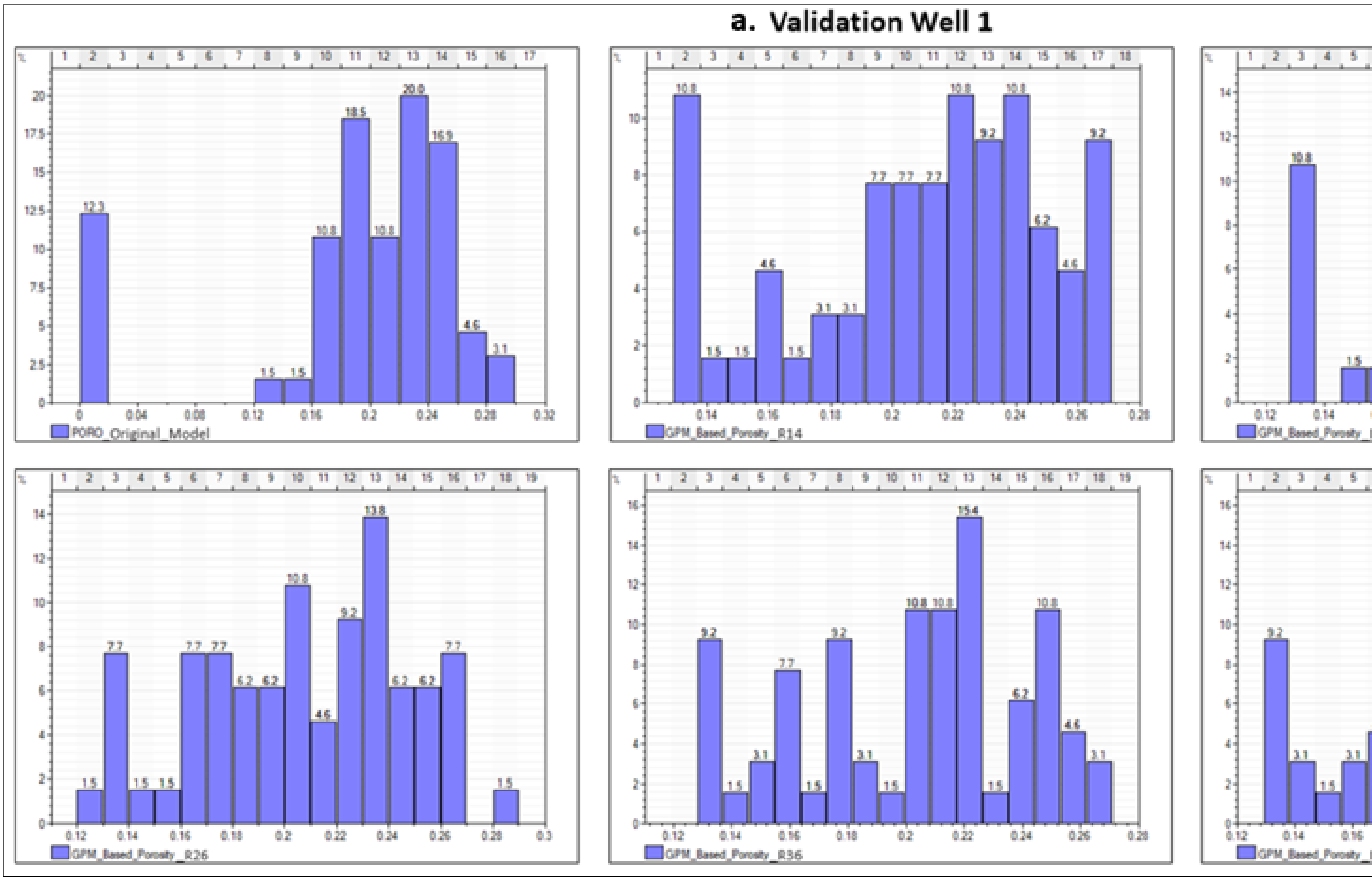


Figure ~~12. Illustrating how; a.~~12a. Samples of validation ~~well~~Well 1 in five selected realizations , and ~~b. validation well 2 samples in the synthetic forward-based model~~how it compares to ~~pseudo wells from~~the samples at similar vertical interval in the original ~~Volve field petrophysical model.~~

porosity and permeability models.

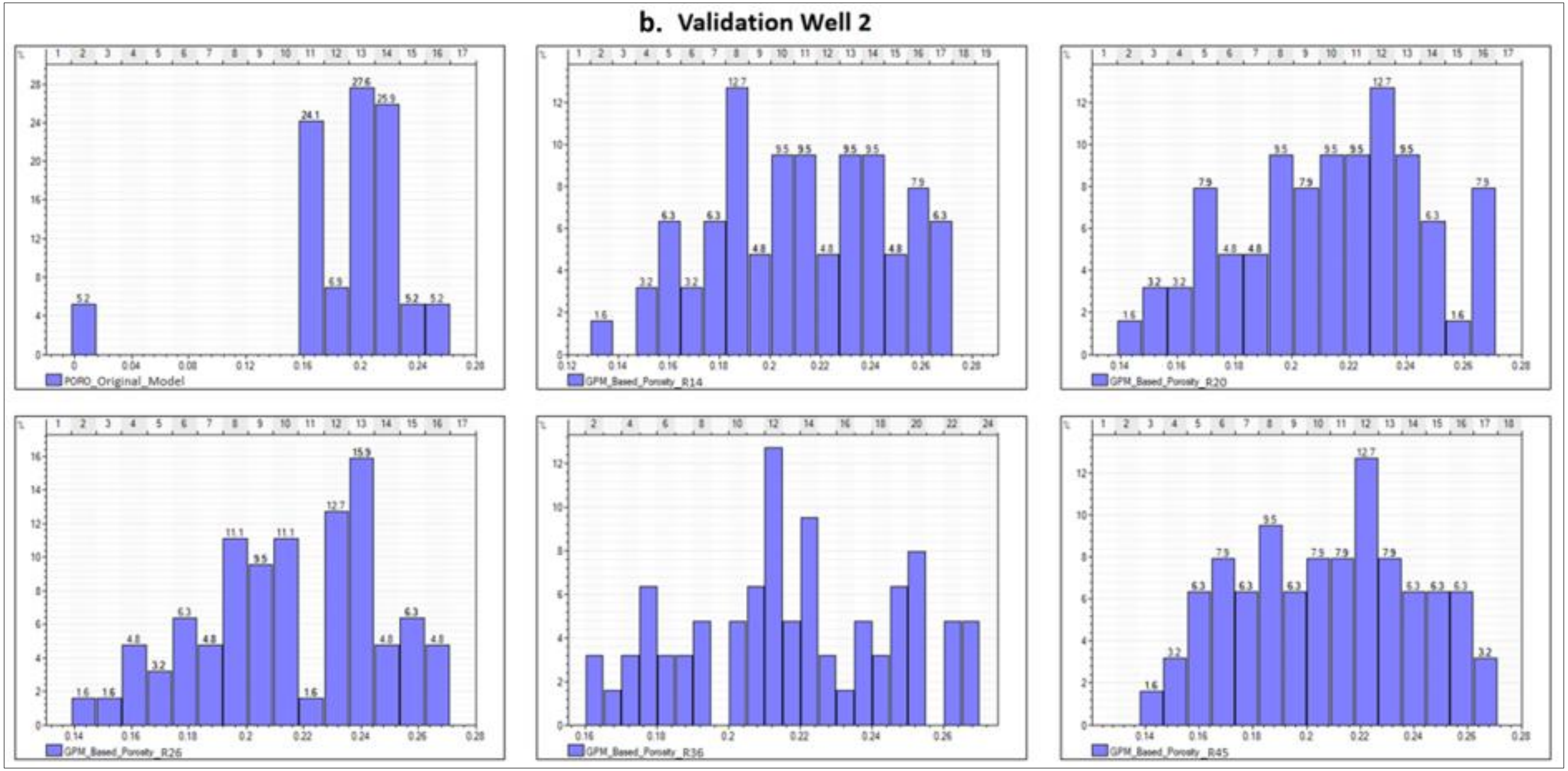
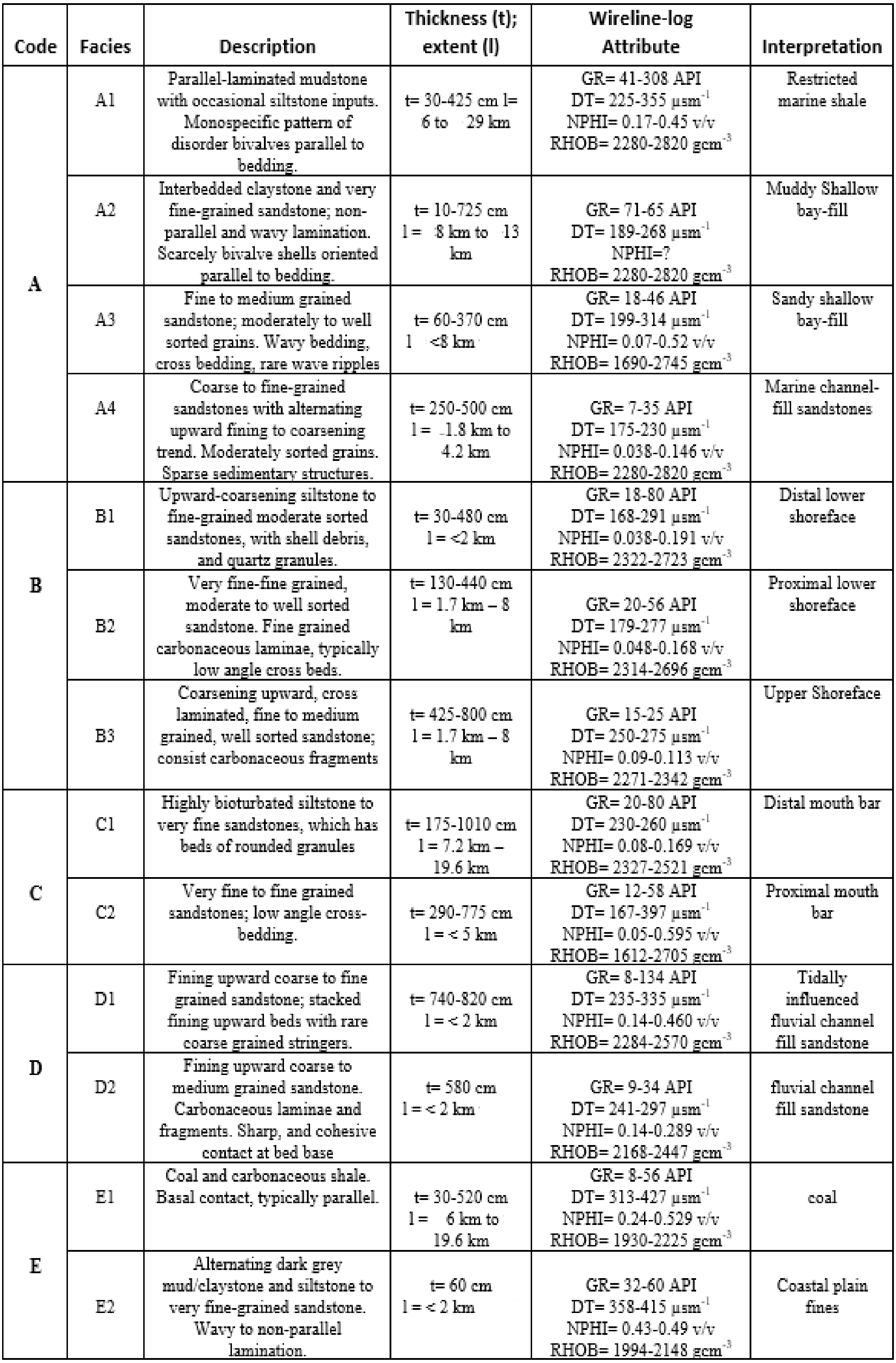


Figure 12b. Samples of validation Well 2 in five selected realizations , and how it compares to the samples at similar vertical interval in the original porosity and permeability models.

Table 1 Lithofacies-associations in the Hugin formation, Volve Field (after Kieft et al. 2011).



Code	Facies	Description	Thickness (t); extent (l)	Wireline-log Attribute	Interpretation
A	A1	Parallel-laminated mudstone with occasional siltstone inputs. Monospecific pattern of disorder bivalves parallel to bedding.	t= 30-425 cm l= 6 to 29 km	GR= 41-308 API DT= 225-355 µsm^{-1} NPHI= 0.17-0.45 v/v RHOB= 2280-2820 gcm^{-3}	Restricted marine shale
	A2	Interbedded claystone and very fine-grained sandstone; non-parallel and wavy lamination. Scarcely bivalve shells oriented parallel to bedding.	t= 10-725 cm l = 8 km to 13 km	GR= 71-65 API DT= 189-268 µsm^{-1} NPHI=? RHOB= 2280-2820 gcm^{-3}	Muddy Shallow bay-fill
	A3	Fine to medium grained sandstone; moderately to well sorted grains. Wavy bedding, cross bedding, rare wave ripples	t= 60-370 cm l <8 km	GR= 18-46 API DT= 199-314 µsm^{-1} NPHI= 0.07-0.52 v/v RHOB= 1690-2745 gcm^{-3}	Sandy shallow bay-fill
	A4	Coarse to fine-grained sandstones with alternating upward fining to coarsening trend. Moderately sorted grains. Sparse sedimentary structures.	t= 250-500 cm l = 1.8 km to 4.2 km	GR= 7-35 API DT= 175-230 µsm^{-1} NPHI= 0.038-0.146 v/v RHOB= 2280-2820 gcm^{-3}	Marine channel-fill sandstones
B	B1	Upward-coarsening siltstone to fine-grained moderate sorted sandstones, with shell debris, and quartz granules.	t= 30-480 cm l = <2 km	GR= 18-80 API DT= 168-291 µsm^{-1} NPHI= 0.038-0.191 v/v RHOB= 2322-2723 gcm^{-3}	Distal lower shoreface
	B2	Very fine-fine grained, moderate to well sorted sandstone. Fine grained carbonaceous laminae, typically low angle cross beds.	t= 130-440 cm l = 1.7 km – 8 km	GR= 20-56 API DT= 179-277 µsm^{-1} NPHI= 0.048-0.168 v/v RHOB= 2314-2696 gcm^{-3}	Proximal lower shoreface
	B3	Coarsening upward, cross laminated, fine to medium grained, well sorted sandstone; consist carbonaceous fragments	t= 425-800 cm l = 1.7 km – 8 km	GR= 15-25 API DT= 250-275 µsm^{-1} NPHI= 0.09-0.113 v/v RHOB= 2271-2342 gcm^{-3}	Upper Shoreface
C	C1	Highly bioturbated siltstone to very fine sandstones, which has beds of rounded granules	t= 175-1010 cm l = 7.2 km – 19.6 km	GR= 20-80 API DT= 230-260 µsm^{-1} NPHI= 0.08-0.169 v/v RHOB= 2327-2521 gcm^{-3}	Distal mouth bar
	C2	Very fine to fine grained sandstones; low angle cross-bedding.	t= 290-775 cm l = < 5 km	GR= 12-58 API DT= 167-397 µsm^{-1} NPHI= 0.05-0.595 v/v RHOB= 1612-2705 gcm^{-3}	Proximal mouth bar
D	D1	Fining upward coarse to fine grained sandstone; stacked fining upward beds with rare coarse grained stringers.	t= 740-820 cm l = < 2 km	GR= 8-134 API DT= 235-335 µsm^{-1} NPHI= 0.14-0.460 v/v RHOB= 2284-2570 gcm^{-3}	Tidally influenced fluvial channel fill sandstone
	D2	Fining upward coarse to medium grained sandstone. Carbonaceous laminae and fragments. Sharp, and cohesive contact at bed base	t= 580 cm l = < 2 km	GR= 9-34 API DT= 241-297 µsm^{-1} NPHI= 0.14-0.289 v/v RHOB= 2168-2447 gcm^{-3}	fluvial channel fill sandstone
E	E1	Coal and carbonaceous shale. Basal contact, typically parallel.	t= 30-520 cm l = 6 km to 19.6 km	GR= 8-56 API DT= 313-427 µsm^{-1} NPHI= 0.24-0.529 v/v RHOB= 1930-2225 gcm^{-3}	coal
	E2	Alternating dark grey mud/claystone and siltstone to very fine-grained sandstone. Wavy to non-parallel lamination.	t= 60 cm l = < 2 km	GR= 32-60 API DT= 358-415 µsm^{-1} NPHI= 0.43-0.49 v/v RHOB= 1994-2148 gcm^{-3}	Coastal plain fines

Table 2. Input parameters applied in running the simulations in GPM^{TM}

For
Bo

Initial Conditions- GPM Input Parameters

		Simulation Duration	Sediment Type Proportion (%)				Avg. Water Velocity	Avg. Sediment Velocity	Erodibility	Diffusion Coefficient	Avg. Sea Level	Turbidite Event Interval	Steady Flow Iteration	Sediment Movement
GPM Scenarios (GS)		(Ma– 0a) Years	Sand (Coarse)	Sand (Fine)	Silt	Clay	(m/a)	(m/a)			Interval (m)	(/years)	(/hrs)	Coefficient
	S1	0.02 – 0	25	25	25	25	0.11	0.03	0.35	0.11	30	2500	10	0.001
	S2	0.25 – 0	25	25	25	25	0.15	0.03	0.45	0.15	70	1000	15	0.012
	S3	0.5 – 0	25	25	25	25	0.11	0.02	0.55	0.11	120	1000	20	0.012
	S4	0.7 – 0.05	25	25	25	25	0.08	0.02	0.35	0.08	100	500	25	0.0011
	S5	1.5 – 0	15	35	30	20	0.15	0.04	0.50	0.15	80	5000	20	0.001
	S6	3.0 – 0	50	25	15	10	0.13	0.04	0.50	0.13	70	5000	30	0.0012
	S7	3.5 – 0	50	25	15	10	0.11	0.04	0.50	0.11	70	10000	15	0.001
	S8	4.0 – 0	50	25	15	10	0.13	0.04	0.50	0.13	90	5000	20	0.0015
	S9	4.5 – 0	15	45	25	15	0.1	0.02	0.45	0.1	50	10000	30	0.0012
	S10	5.0 – 0	15	45	25	15	0.12	0.02	0.45	0.12	55	10000	35	0.0013
	S11	5.5 - 0	15	45	25	15	0.12	0.02	0.45	0.12	40	5000	40	0.0013
	S12	6.0 – 0	15	45	25	15	0.1	0.02	0.45	0.1	60	10000	35	0.0011
	S13	6.5 – 0	10	25	55	10	0.13	0.03	0.48	0.13	100	20000	50	0.0010
	S14	7.0 – 0	10	25	55	10	0.16	0.03	0.48	0.16	40	20000	45	0.0011
	S15	7.5 – 0	10	25	55	10	0.13	0.03	0.48	0.13	40	20000	40	0.0012
	S16	8.0 – 0	10	25	55	10	0.15	0.03	0.48	0.15	30	10000	30	0.0010
	S17	8.5 – 0	10	25	45	20	0.14	0.02	0.45	0.14	50	50000	50	0.0010
	S18	9.0 – 0	30	30	18	22	0.13	0.02	0.52	0.13	60	25000	35	0.0012
	S19	9.5 – 0	30	40	12	18	0.12	0.02	0.55	0.12	55	25000	20	0.0013
	S20	10.0 - 0	30	42	18	10	0.11	0.01	0.40	0.11	50	5000	15	0.0011

Sediment Property

Sediment Type	Diameter	Density	Initial Porosity	Initial Permeability	Compacted Porosity	Compaction	Compacted Permeability	Erodibility
Coarse Grained Sand	1.0 mm	2.70 g/cm^3	0.21 m^3/m^3	500 mD	0.25 m^3/m^3	5000 KPa	50 mD	0.6
Fine Grained Sand	0.1 mm	2.70 g/cm^3	0.3 m^3/m^3	100 mD	0.15 m^3/m^3	2500 KPa	5 mD	0.45
Silt	0.01 mm	2.65 g/cm^3	0.38 m^3/m^3	50 mD	0.12 m^3/m^3	1200 KPa	2 mD	0.3
Clay	0.001 mm	2.65 g/cm^3	0.48 m^3/m^3	5 mD	0.05 m^3/m^3	500 KPa	0.1 mD	0.15

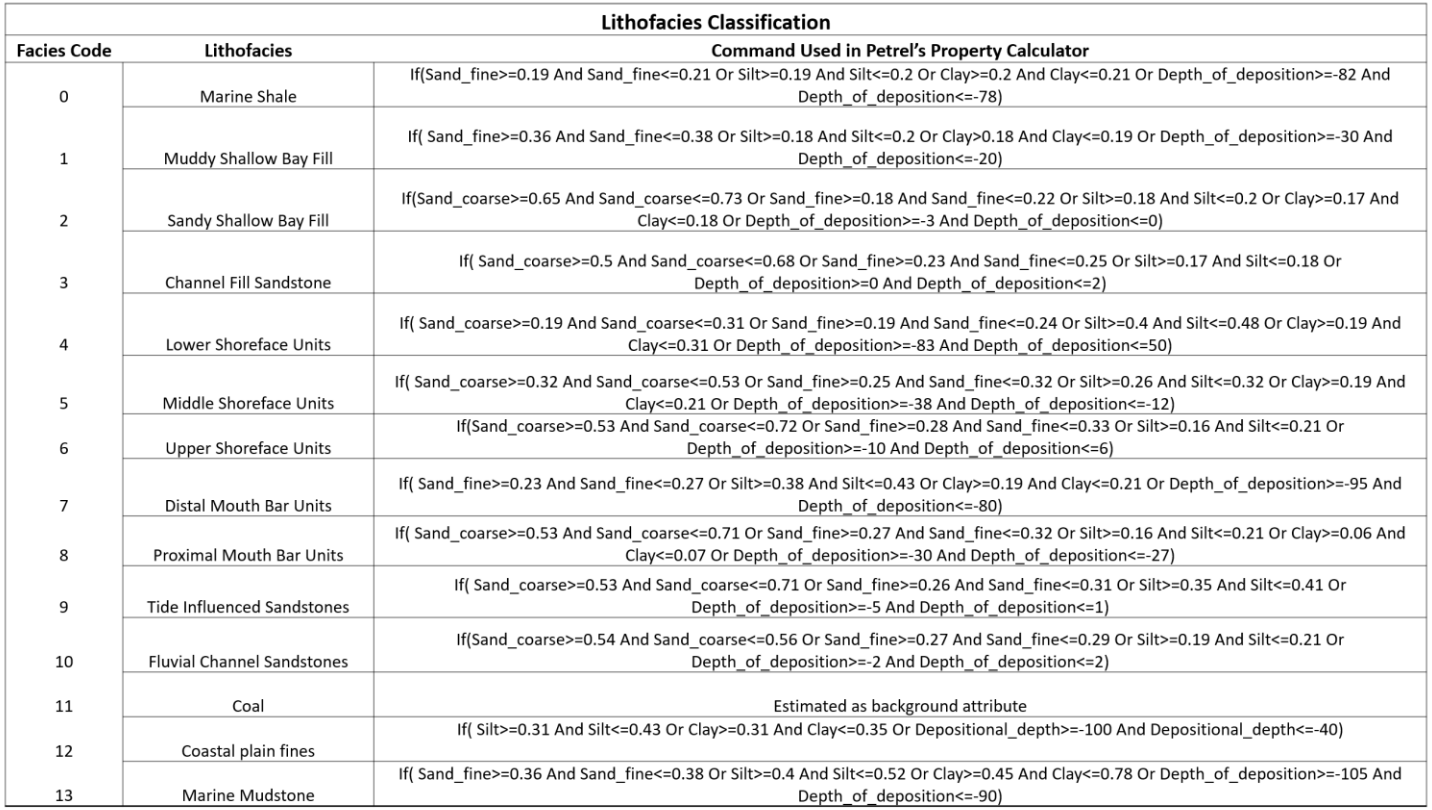
Initial Conditions- GPM Input Parameters

		Simulation Duration	Sediment Type Proportion (%)				Avg. Water Velocity	Avg. Sediment Velocity	Erodibility	Diffusion Coefficient	Avg. Sea Level	Turbidite Event Interval	Steady Flow Iteration	Sediment Movement
		(Ma– 0a) Years	Sand (Coarse)	Sand (Fine)	Silt	Clay	(m/a)	(m/a)			Interval (m)	(/years)	(/hrs)	Coefficient
GPM Scenarios (GS)	S1	0.02 – 0	25	25	25	25	0.11	0.03	0.35	0.11	30	2500	10	0.001
	S2	0.25 – 0	25	25	25	25	0.15	0.03	0.45	0.15	70	1000	15	0.012
	S3	0.5 – 0	25	25	25	25	0.11	0.02	0.55	0.11	120	1000	20	0.012
	S4	0.7 – 0.05	25	25	25	25	0.08	0.02	0.35	0.08	100	500	25	0.0011
	S5	1.5 – 0	15	35	30	20	0.15	0.04	0.50	0.15	80	5000	20	0.001
	S6	3.0 – 0	50	25	15	10	0.13	0.04	0.50	0.13	70	5000	30	0.0012
	S7	3.5 – 0	50	25	15	10	0.11	0.04	0.50	0.11	70	10000	15	0.001
	S8	4.0 – 0	50	25	15	10	0.13	0.04	0.50	0.13	90	5000	20	0.0015
	S9	4.5 – 0	15	45	25	15	0.1	0.02	0.45	0.1	50	10000	30	0.0012
	S10	5.0 – 0	15	45	25	15	0.12	0.02	0.45	0.12	55	10000	35	0.0013
	S11	5.5 - 0	15	45	25	15	0.12	0.02	0.45	0.12	40	5000	40	0.0013
	S12	6.0 – 0	15	45	25	15	0.1	0.02	0.45	0.1	60	10000	35	0.0011
	S13	6.5 – 0	10	25	55	10	0.13	0.03	0.48	0.13	100	20000	50	0.0010
	S14	7.0 – 0	10	25	55	10	0.16	0.03	0.48	0.16	40	20000	45	0.0011
	S15	7.5 – 0	10	25	55	10	0.13	0.03	0.48	0.13	40	20000	40	0.0012
	S16	8.0 – 0	10	25	55	10	0.15	0.03	0.48	0.15	30	10000	30	0.0010
	S17	8.5 – 0	10	25	45	20	0.14	0.02	0.45	0.14	50	50000	50	0.0010
	S18	9.0 – 0	30	30	18	22	0.13	0.02	0.52	0.13	60	25000	35	0.0012
	S19	9.5 – 0	30	40	12	18	0.12	0.02	0.55	0.12	55	25000	20	0.0013
	S20	10.0 - 0	30	42	18	10	0.11	0.01	0.40	0.11	50	5000	15	0.0011

Sediment Property

	Sediment Type	Diameter	Density	Initial Porosity	Initial Permeability	Compacted Porosity	Compaction	Compacted Permeability	Erodibility
	Coarse Grained Sand	1.0 mm	2.70 g/cm^3	0.21 m^3/m^3	500 mD	0.25 m^3/m^3	5000 KPa	50 mD	0.6
	Fine Grained Sand	0.1 mm	2.70 g/cm^3	0.3 m^3/m^3	100 mD	0.15 m^3/m^3	2500 KPa	5 mD	0.45
	Silt	0.01 mm	2.65 g/cm^3	0.38 m^3/m^3	50 mD	0.12 m^3/m^3	1200 KPa	2 mD	0.3
	Clay	0.001 mm	2.65 g/cm^3	0.48 m^3/m^3	5 mD	0.05 m^3/m^3	500 KPa	0.1 mD	0.15

Table 3. Lithofacies classification in the forward stratigraphic model; showing the command used in the property calculator tool in Petrel^{TM}.

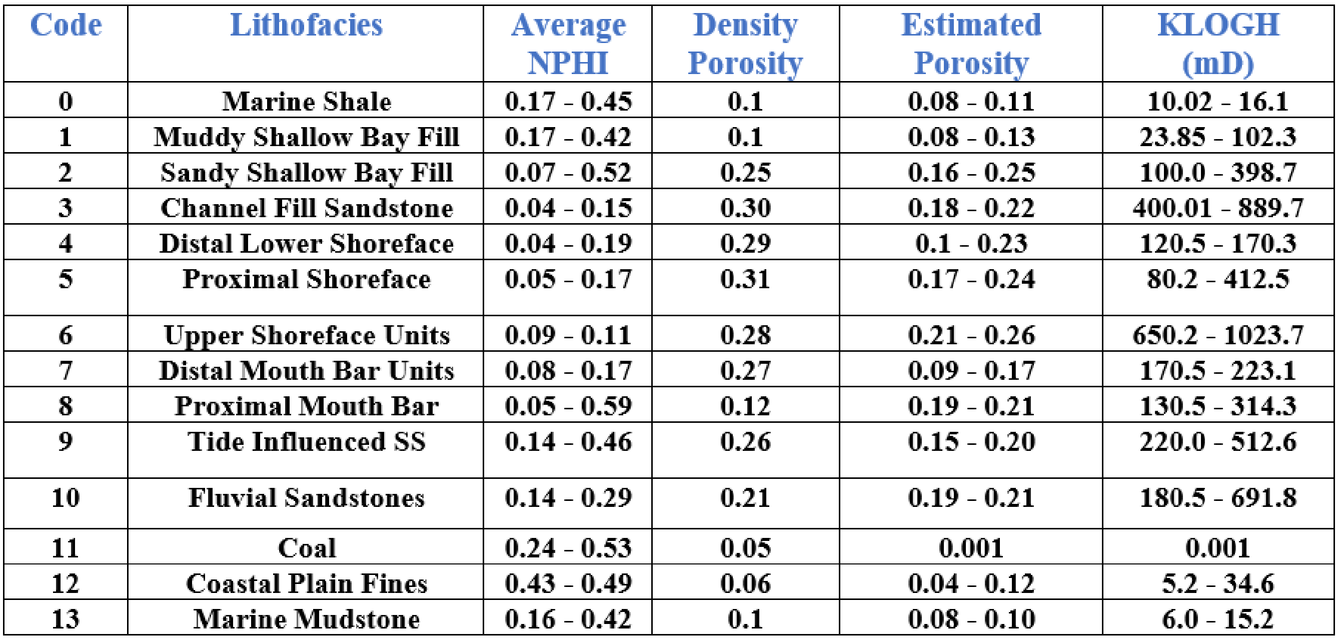


Lithofacies Classification		
Facies Code	**Lithofacies**	**Command Used in Petrel's Property Calculator**
0	Marine Shale	If(Sand_fine>=0.19 And Sand_fine<=0.21 Or Silt>=0.19 And Silt<=0.2 Or Clay>=0.2 And Clay<=0.21 Or Depth_of_deposition>=-82 And Depth_of_deposition<=-78)
1	Muddy Shallow Bay Fill	If(Sand_fine>=0.36 And Sand_fine<=0.38 Or Silt>=0.18 And Silt<=0.2 Or Clay>0.18 And Clay<=0.19 Or Depth_of_deposition>=-30 And Depth_of_deposition<=-20)
2	Sandy Shallow Bay Fill	If(Sand_coarse>=0.65 And Sand_coarse<=0.73 Or Sand_fine>=0.18 And Sand_fine<=0.22 Or Silt>=0.18 And Silt<=0.2 Or Clay>=0.17 And Clay<=0.18 Or Depth_of_deposition>=-3 And Depth_of_deposition<=0)
3	Channel Fill Sandstone	If(Sand_coarse>=0.5 And Sand_coarse<=0.68 Or Sand_fine>=0.23 And Sand_fine<=0.25 Or Silt>=0.17 And Silt<=0.18 Or Depth_of_deposition>=0 And Depth_of_deposition<=2)
4	Lower Shoreface Units	If(Sand_coarse>=0.19 And Sand_coarse<=0.31 Or Sand_fine>=0.19 And Sand_fine<=0.24 Or Silt>=0.4 And Silt<=0.48 Or Clay>=0.19 And Clay<=0.31 Or Depth_of_deposition>=-83 And Depth_of_deposition<=50)
5	Middle Shoreface Units	If(Sand_coarse>=0.32 And Sand_coarse<=0.53 Or Sand_fine>=0.25 And Sand_fine<=0.32 Or Silt>=0.26 And Silt<=0.32 Or Clay>=0.19 And Clay<=0.21 Or Depth_of_deposition>=-38 And Depth_of_deposition<=-12)
6	Upper Shoreface Units	If(Sand_coarse>=0.53 And Sand_coarse<=0.72 Or Sand_fine>=0.28 And Sand_fine<=0.33 Or Silt>=0.16 And Silt<=0.21 Or Depth_of_deposition>=-10 And Depth_of_deposition<=6)
7	Distal Mouth Bar Units	If(Sand_fine>=0.23 And Sand_fine<=0.27 Or Silt>=0.38 And Silt<=0.43 Or Clay>=0.19 And Clay<=0.21 Or Depth_of_deposition>=-95 And Depth_of_deposition<=-80)
8	Proximal Mouth Bar Units	If(Sand_coarse>=0.53 And Sand_coarse<=0.71 Or Sand_fine>=0.27 And Sand_fine<=0.32 Or Silt>=0.16 And Silt<=0.21 Or Clay>=0.06 And Clay<=0.07 Or Depth_of_deposition>=-30 And Depth_of_deposition<=-27)
9	Tide Influenced Sandstones	If(Sand_coarse>=0.53 And Sand_coarse<=0.71 Or Sand_fine>=0.26 And Sand_fine<=0.31 Or Silt>=0.35 And Silt<=0.41 Or Depth_of_deposition>=-5 And Depth_of_deposition<=1)
10	Fluvial Channel Sandstones	If(Sand_coarse>=0.54 And Sand_coarse<=0.56 Or Sand_fine>=0.27 And Sand_fine<=0.29 Or Silt>=0.19 And Silt<=0.21 Or Depth_of_deposition>=-2 And Depth_of_deposition<=2)
11	Coal	Estimated as background attribute
12	Coastal plain fines	If(Silt>=0.31 And Silt<=0.43 Or Clay>=0.31 And Clay<=0.35 Or Depositional_depth>=-100 And Depositional_depth<=-40)
13	Marine Mudstone	If(Sand_fine>=0.36 And Sand_fine<=0.38 Or Silt>=0.4 And Silt<=0.52 Or Clay>=0.45 And Clay<=0.78 Or Depth_of_deposition>=-105 And Depth_of_deposition<=-90)

Lithofacies Classification

Facies Code	Lithofacies	Command Used in Petrel's Property Calculator
0	Marine Shale	If(Sand_fine>=0.19 And Sand_fine<=0.21 Or Silt>=0.19 And Silt<=0.2 Or Clay>=0.2 And Clay<=0.21 Or Depth_of_deposition>=-82 And Depth_of_deposition<=-78)
1	Muddy Shallow Bay Fill	If(Sand_fine>=0.36 And Sand_fine<=0.38 Or Silt>=0.18 And Silt<=0.2 Or Clay>0.18 And Clay<=0.19 Or Depth_of_deposition>=-30 And Depth_of_deposition<=-20)
2	Sandy Shallow Bay Fill	If(Sand_coarse>=0.65 And Sand_coarse<=0.73 Or Sand_fine>=0.18 And Sand_fine<=0.22 Or Silt>=0.18 And Silt<=0.2 Or Clay>=0.17 And Clay<=0.18 Or Depth_of_deposition>=-3 And Depth_of_deposition<=0)
3	Channel Fill Sandstone	If(Sand_coarse>=0.5 And Sand_coarse<=0.68 Or Sand_fine>=0.23 And Sand_fine<=0.25 Or Silt>=0.17 And Silt<=0.18 Or Depth_of_deposition>=0 And Depth_of_deposition<=2)
4	Lower Shoreface Units	If(Sand_coarse>=0.19 And Sand_coarse<=0.31 Or Sand_fine>=0.19 And Sand_fine<=0.24 Or Silt>=0.4 And Silt<=0.48 Or Clay>=0.19 And Clay<=0.31 Or Depth_of_deposition>=-83 And Depth_of_deposition<=50)
5	Middle Shoreface Units	If(Sand_coarse>=0.32 And Sand_coarse<=0.53 Or Sand_fine>=0.25 And Sand_fine<=0.32 Or Silt>=0.26 And Silt<=0.32 Or Clay>=0.19 And Clay<=0.21 Or Depth_of_deposition>=-38 And Depth_of_deposition<=-12)
6	Upper Shoreface Units	If(Sand_coarse>=0.53 And Sand_coarse<=0.72 Or Sand_fine>=0.28 And Sand_fine<=0.33 Or Silt>=0.16 And Silt<=0.21 Or Depth_of_deposition>=-10 And Depth_of_deposition<=6)
7	Distal Mouth Bar Units	If(Sand_fine>=0.23 And Sand_fine<=0.27 Or Silt>=0.38 And Silt<=0.43 Or Clay>=0.19 And Clay<=0.21 Or Depth_of_deposition>=-95 And Depth_of_deposition<=-80)
8	Proximal Mouth Bar Units	If(Sand_coarse>=0.53 And Sand_coarse<=0.71 Or Sand_fine>=0.27 And Sand_fine<=0.32 Or Silt>=0.16 And Silt<=0.21 Or Clay>=0.06 And Clay<=0.07 Or Depth_of_deposition>=-30 And Depth_of_deposition<=-27)
9	Tide Influenced Sandstones	If(Sand_coarse>=0.53 And Sand_coarse<=0.71 Or Sand_fine>=0.26 And Sand_fine<=0.31 Or Silt>=0.35 And Silt<=0.41 Or Depth_of_deposition>=-5 And Depth_of_deposition<=1)
10	Fluvial Channel Sandstones	If(Sand_coarse>=0.54 And Sand_coarse<=0.56 Or Sand_fine>=0.27 And Sand_fine<=0.29 Or Silt>=0.19 And Silt<=0.21 Or Depth_of_deposition>=-2 And Depth_of_deposition<=2)
11	Coal	Estimated as background attribute
12	Coastal plain fines	If(Silt>=0.31 And Silt<=0.43 Or Clay>=0.31 And Clay<=0.35 Or Depositional_depth>=-100 And Depositional_depth<=-40)
13	Marine Mudstone	If(Sand_fine>=0.36 And Sand_fine<=0.38 Or Silt>=0.4 And Silt<=0.52 Or Clay>=0.45 And Clay<=0.78 Or Depth_of_deposition>=-105 And Depth_of_deposition<=-90)

Table 4. Porosity and Permeability estimate in identified lithofacies packages.



Code	Lithofacies	Average NPHI	Density Porosity	Estimated Porosity	KLOGH (mD)
0	Marine Shale	0.17 - 0.45	0.1	0.08 - 0.11	10.02 - 16.1
1	Muddy Shallow Bay Fill	0.17 - 0.42	0.1	0.08 - 0.13	23.85 - 102.3
2	Sandy Shallow Bay Fill	0.07 - 0.52	0.25	0.16 - 0.25	100.0 - 398.7
3	Channel Fill Sandstone	0.04 - 0.15	0.30	0.18 - 0.22	400.01 - 889.7
4	Distal Lower Shoreface	0.04 - 0.19	0.29	0.1 - 0.23	120.5 - 170.3
5	Proximal Shoreface	0.05 - 0.17	0.31	0.17 - 0.24	80.2 - 412.5
6	Upper Shoreface Units	0.09 - 0.11	0.28	0.21 - 0.26	650.2 - 1023.7
7	Distal Mouth Bar Units	0.08 - 0.17	0.27	0.09 - 0.17	170.5 - 223.1
8	Proximal Mouth Bar	0.05 - 0.59	0.12	0.19 - 0.21	130.5 - 314.3
9	Tide Influenced SS	0.14 - 0.46	0.26	0.15 - 0.20	220.0 - 512.6
10	Fluvial Sandstones	0.14 - 0.29	0.21	0.19 - 0.21	180.5 - 691.8
11	Coal	0.24 - 0.53	0.05	0.001	0.001
12	Coastal Plain Fines	0.43 - 0.49	0.06	0.04 - 0.12	5.2 - 34.6
13	Marine Mudstone	0.16 - 0.42	0.1	0.08 - 0.10	6.0 - 15.2

Table 5. Comparison of a) porosity, and b) permeability estimates in original petrophysical model and forward modeling-based porosity and permeability models.

a. Validation Well Position 1							
	Porosity: GPM-Based Model					**Porosity: Original Model**	
	Depth (m)						
Models	5 m	10 m	15 m	25 m	35 m	**Depth (m)**	**Average Porosity**
R14	0.22	0.24	0.16	0.22	0.16	5	0.2
R20	0.16	0.19	0.26	0.18	0.15	10	0.25
R26	0.18	0.17	0.23	0.16	0.19	15	0.27
R36	0.22	0.21	0.19	0.22	0.21	25	0.16
R45	0.25	0.2	0.23	0.22	0.15	35	0.13
R49	0.21	0.17	0.22	0.17	0.18		
Validation Well Position 2							
	Porosity: GPM-Based Model					**Porosity: Original Model**	
	Depth (m)						
Models	5 m	10 m	15 m	25 m	35 m	**Depth (m)**	**Average Porosity**
R14	0.17	0.16	0.24	0.15	0.25	5	0.17
R20	0.21	0.22	0.2	0.21	0.23	10	0.21
R26	0.21	0.2	0.21	0.25	0.24	15	0.21
R36	0.2	0.22	0.21	0.21	0.19	25	0.17
R45	0.22	0.19	0.2	0.19	0.21	35	0.19
R49	0.26	0.24	0.23	0.16	0.21		

b. Validation Well Position 1							
	Permeability_Z (mD): GPM-Based Model					**Permeability_Z: Original Model**	
	Depth (m)						
Models	5 m	10 m	15 m	25 m	35 m	**Depth (m)**	**Average Perm_Z**
R14	163.95	312.38	69.84	310.16	508.2	5	352.74
R20	290.84	315.09	105.66	273.04	200.63	10	312.38
R26	375.92	203.81	166.23	189.92	348.12	15	201.08
R36	418.03	203.27	190.9	168.9	370.56	25	199.76
R45	337.6	412.67	199.66	156.71	305.92	35	508.2
R49	370.89	129.33	291.77	175.53	551.18		
Validation Well Position 2							
	Permeability_Z (mD): GPM-Based Model					**Permeability_Z: Original Model**	
	Depth (m)						
Models	5 m	10 m	15 m	25 m	35 m	**Depth (m)**	**Average Perm_Z**
R14	320.34	336.22	151.08	464.22	132.98	5	6.6
R20	122.66	209.15	161.3	230.58	208.48	10	883.6
R26	151.48	710.07	175.09	384.49	169.48	15	30.3
R36	184.74	344.99	157.08	420.15	136.14	25	496.99
R45	91.44	361.04	77.17	382.85	134.56	35	156.6
R49	134.01	721.73	137.42	636.48	290.06		