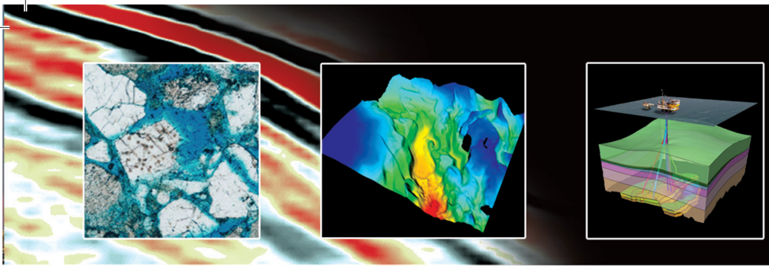


The Geological Society

serving science, profession & society

Corporate Supporters:

Convenors:

Matt Jameson
Glencore

Gwilym Lynn
Shell

Leigh Truelove
Schlumberger

Ingrid Demaerschalk
Tullow

Alun Griffiths
Rockhopper

Catherine Tonge
Shell

David Hulme
Equinor

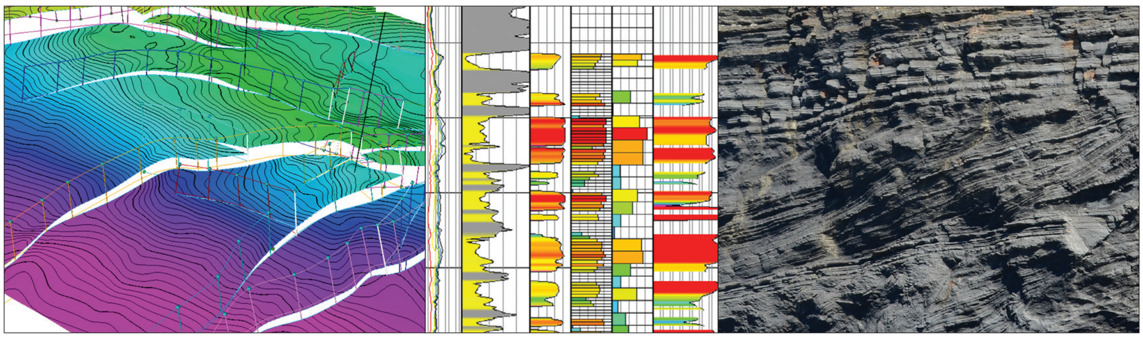
Tom Marsh
Rock Flow Dynamics

James Aguas
Halliburton

Capturing Geoscience in Geomodels

26-27 June 2019

Robert Gordon University, Aberdeen



PROGRAMME AND ABSTRACT VOLUME

Sponsored by:

At the forefront of petroleum geoscience

www.geolsoc.org.uk/petroleum

Capturing Geoscience in Geomodels

26-27 June 2019

Robert Gordon University, Aberdeen

Corporate Supporters

Conference Sponsors

CONTENTS PAGE

CONFERENCE PROGRAMME

	Day One
	Registration
	Welcome
	Geomodelling Concepts
09.10	**The Decline and Fall of Production Geology: How Geomodelling has poisoned Everything** Juan Cottier, *MMbbls*
09.40	**Modelling for Understanding** Mark Bentley, *TRACS & Heriot Watt University*
10.10	**Honest and critical thinking: how to make approximately accurate geological models, whilst avoiding being precisely wrong** Luke Johnson, *Cognetive Geology*
10.40	**Break**
11.10	**Multi-scenario modelling for Cambo field development planning, UK West of Shetlands** Noah Jaffey, *Shell*
11.40	**Rapid Reservoir Modelling: Prototyping of reservoir geoscience and development concepts using sketch-based interface and modelling** Matthew Jackson, *Imperial College London*
12.10	**AI based property modelling calibrated by forward sediment simulation** Colin Daly & Leigh Truelove, *Schlumberger*
12.40	**Lunch**
13.40	**Geostatistics and data mining from digital outcrop models for reducing uncertainty in subsurface reservoirs** David Hodgetts, *University of Manchester*
14.10	**Machine Learning Methodologies Provide New Insights into the Reservoir in Seismic Interpretation** Lorena Guerra, *Emerson Automation Solutions*
14.40	**Modelling and Simulation of Heterogeneous and Anisotropic Reservoirs using a Fractal Approach** Paul Glover, *University of Leeds*
15.10	**Break**
15.40	**A methodology for differentiation of facies in the heterolithic Triassic of Culzean** John Banks, *Total*
16.10	**A hierarchical workflow conditioning facies models to well data and realistic connectivity** Deirdre Walsh, *iCRAG*
16.40	**Leveraging regional geology and conceptual models at the field and reservoir scale: building more reliable earth models under sparse data conditions** Kate Evans, *Halliburton*
17.10	**Finish**
	Drinks Reception

Day Two	
	Registration
	Welcome
	Dynamic and Static Modelling
09.10	**Uncertainty: Battling our Bias Demons** Greg Stone, *Shell*
09.40	**What's inside the loop** David Cox, *BP*
10.10	**Petrophysical Uncertainties in Geomodels** Alan Johnson, *IPS Petrophysics*
10.40	**Break**
11.10	**Reducing uncertainty in reservoir models using structural modelling and analysis** Andrew Bladon, *PETEX*
11.40	**Uncertainty Modelling: Moving away from the 'Base Case' central tendency bias** Smruti Ranjan Jena, *Chrysoar*
12.10	**Integration of forward stratigraphic modeling with Interpreted and geostatistical data for building better predictive reservoir models** Sergio Courtade, *Schlumberger*
12.40	**Lunch**
13.40	**Reimagining History Matching in an Uncertainty Modelling Context** Martha Stunell, *Resoptima*
14.10	**A Benchmark of Sensitivity Analysis Methods to assess the Dynamic Impact of Structural and Petrophysical Uncertainties** Gabriel Godfroy, *Total*
14.40	**Lower Captain Sandstone: The Importance of Data Integration in Geocellular Modelling and History Matching** Karl Charvin, *Chevron Upstream Europe*
15.10	**Break**
15.40	**Structural and Sedimentological controls on the performance of deeply buried aeolian gas reservoirs** Sophie Behrendsen, *University of Aberdeen*
16.10	**Closing remarks**
	Finish

POSTER PROGRAMME

Poster Programme Day One
Capturing Large Scale Conceptual Geology in the Enyenra Field Douglas Obeng, *Tullow Ghana Limited*
Risking across-fault juxtaposition using an empirically calibrated fault zone model Tom Manzocchi, *University College Dublin*
Assessing and communicating risk in early stage exploration: embedding regional understanding within basin modelling workflows Natasha Dowey, *Halliburton*
Improving reservoir facies modelling with analogue databases Simon Lomas, *Petrotechnical Data Systems Ltd*
The impact of structural and water saturation uncertainties on reservoir models Mark Verschuren, *Petrotechnical Data Systems Ltd*
Quantitative Analysis of 3D Sub Surface Modelling Updates While Drilling Simon Austin, *Baker Hughes a GE company*
New, Integrated Geology-to-Geomechanics Workflows Offer Production Risk Mitigation without Compromising Reservoir Complexity Camille Cosson, *Emerson Automation Solutions*
Leveraging 4D Seismic into the Static Model: a Simple Approach in a Deep Water Lobe Reservoir, Paladio Field, Block 18, Offshore Angola Neila da Costa Mendes, *BP Angola*
Simulation of Turbidites with Forward Stratigraphic Modeling Sergio Courtade, *Schlumberger*
Applying Geological Process Simulation Outputs to Constrain Lithofacies Modeling in a Basinal Fan Geological Setting: An Example Daniel Otoo, *University of Manchester*
Poster Programme Day Two
Reproducing net:gross and amalgamation ratios in rule-based models of deep-water lobe systems Javier Lopez-Cabrera, *University College Dublin*
Bridging the Gap between Rocks and Recoverables in Tight Gas Behrooz Bashokooh, *Shell*
Surface-based reservoir modelling: Generating realistic geological heterogeneity for reservoir modelling and simulation Carl Jacquemyn, *Imperial College London*
Virtual Outcrop-based analysis of channel and crevasse splay sandstone body architecture in the Middle Jurassic Ravenscar Group, Yorkshire, NE England M. Mostafizur Rahman, *University of Aberdeen*
Building a discrete fracture network model from vintage data in old oil fields: a case from the Southern Apennine hydrocarbon province Paolo Pace, *GR Plan*
Assessing and communicating risk in early stage exploration: embedding regional understanding within basin modelling workflows Natasha Dowey, *Halliburton*

Novel 2D/3D seismic forward modelling of the seal bypass structure: an example from the Loyal field of the North Sea (Scotland, UK) Zhihua Cui, *University of Aberdeen*
Three-dimensional modelling of volcanic facies architecture; the application of virtual outcrops to aid stratigraphic interpretation and prediction Jessica H. Pugsley, *University of Aberdeen*
Realistic geological modelling of complex discrete fracture networks Pat Fothergill, *Golder Associates (UK) Ltd*

Oral Presentation Abstracts
(Presentation order)

Day One:

Geomodelling Concepts

The Decline and Fall of Production Geology: How Geomodelling has Poisoned Everything.

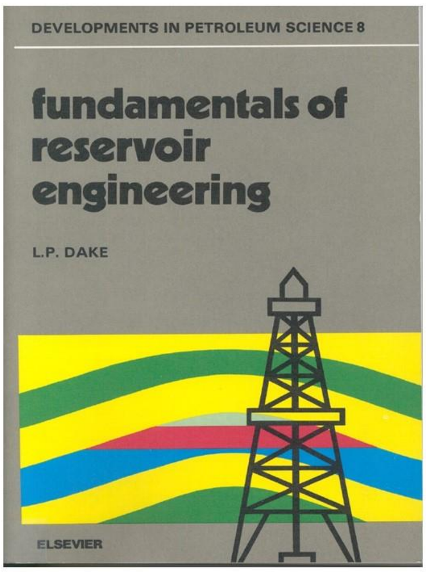
Juan W Cottier
MMbbls Limited, Isle of Man

The geological description of subsurface reservoirs has always been a core component to maximising hydrocarbon resources, and thus generating profits for Oil & Gas companies. The skills required to describe a reservoir have grown and complimented each other from the earliest days of the geological discipline. However, this conference presentation will show that changes in subsurface practice, over the last 20 years, driven by geomodelling, have led to the diminution, the side-lining, and even the loss of Production Geology and Reservoir Engineering skills.

Static 3D geomodelling software has been available since the early 1990s and geomodelling has been standard industry practice since the mid 2000s. Dynamic reservoir simulation has been available even earlier, since the 1970s, and has been standard practice since the late 1980s. 3D geomodelling has required, or has at least facilitated, a change of emphasis in how reservoirs are described. As examples; the basis of construction is now gridding rather than mapping; reservoir description is heavily statistical rather than anchored on depositional concepts; and the QC process relies on 3D visualisation and statistics rather than analytical modelling and "sense checks".

Over the last 20 years, traditional Production Geology skills such as structural mapping, fault networks, allan-diagrams, cartography, conceptual modelling, and sedimentology have been abandoned and replaced by a wide variety of automated or semi-automated tools found within integrated geomodelling packages. These tools, such as zone modelling, contouring, fault modelling, data loading and QC, and log analysis automate to such an extent that the geologist no longer needs to take time to ponder, consider, or even to think. In many cases these tools are not even geological tools, but processes required by the software to produce a discretised, numerical model (e.g. gridding, averaging, variograms, upscaling), developed by software personnel with minimal oilfield experience.

Reservoir Engineering fares no better. Classical analytical techniques such as material balance, fractional flow and decline curve analysis, along with well-established simulation techniques such as sector or decision modelling have been replaced with generic, semi-automated, full-field reservoir simulation. As with the newly created discipline of "Geomodeller" rather than Geologist, we also have the newly created discipline of "Simulation Engineer" rather than Reservoir Engineer.



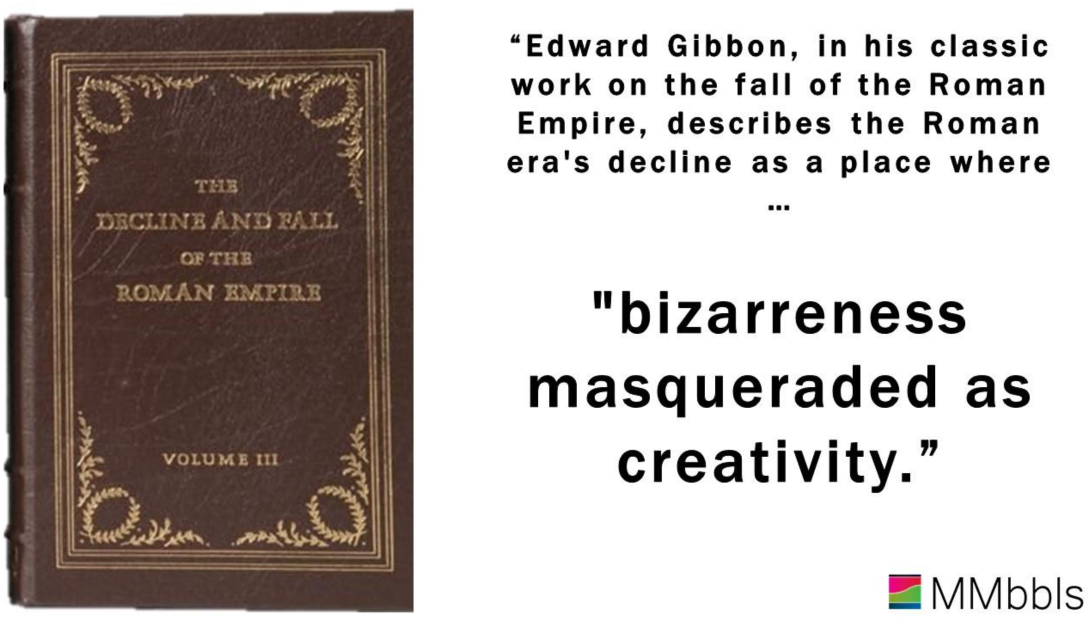
"There is no such thing as a Simulation Engineer, only reservoir engineers who happen to have simulation packages at their disposal for use, amongst other tools, as and when required. If mathematics is used carefully and correctly then we should have a great advantage over our predecessors in this subject."

(LP Dake)

Ironically, despite being marketed as "latest technology", many geomodelling and simulation solutions are extremely dated. They are often clumsy (gridding), historical (coordinate systems, projections, spheroids), or fatally flawed (TPFA). Concomitantly, and disappointingly, genuinely new technologies of the last 10 years are not being implemented (voice command, touch screen, holographics, MPFA, gridless/nodeless simulation, quantum computing, IoT).

Many solutions provided by geomodelling are considerably poorer than the traditional methods and those solutions are now executed by "geomodeller" Geologists and "simulation" Reservoir Engineers. Compounding this loss of expertise has been the ongoing loss of experienced oil industry staff through rationalisation (aka lay-offs). Fortunately, this generalisation of solutions and expertise can be alleviated by collaboration with experts from industry and especially academia.

It is not the remit of software companies to improve the capability of the individual or the decision-making of the Team. Therefore this presentation will address areas and techniques that the Geologist and Reservoir Engineer can adopt to ensure they use the tools available to best support their assets and their asset Teams.



NOTES:

Modelling for Understanding

Mark Bentley
TRACS Training & Heriot-Watt University

Reservoir modelling and simulation is generally seen as a tool for tackling reservoir-related problems, with the object of finding optimised solutions which can be implemented practically to generate value. This is a construction, and can be challenged.

Finding a solution by building a single 'best guess' model is generally well-understood to be a flawed process in the face of limited data and significant uncertainties, although it is commonly selected as an option. Improved solutions based on modelling of uncertainties either by deterministic scenarios or probabilistic ensembles (or a combination) have been a significant improvement, although anchoring and overconfidence heuristics tend to limit our forecast ranges.

In instances where uncertainties are high, and the anchoring tendency is overcome, the forecasts from multiple-modelling exercises often show a very wide range, to the point that a clear 'solution' is not the outcome. The modelling work is effectively stating that the outcome is highly uncertain. As this was probably known before the modelling started, it begs the question, "what was the point of all that modelling work?"

Although the modelling work is not delivering a useful solution, a wide forecast range may nevertheless be an honest and correct result. In this case, it is appropriate to challenge the commonly held construction:

problem ⟶ model ⟶ solution

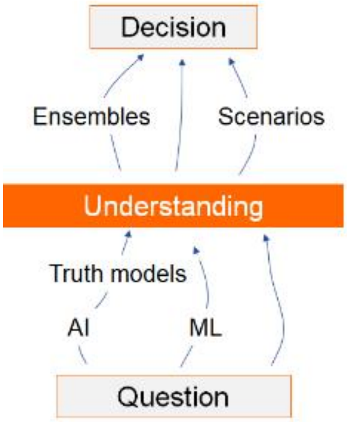
… and replace it with:

question ⟶ understanding ⟶ decision

In this case we are no longer modelling for *solutions*, we are modelling for *understanding*, which is a different thing and most likely leads us to completely different model designs and workflows. These workflows are often more efficient than large-scale, solution-oriented studies.

The emphasis on understanding may drive us to model small scale displacement processes (so-called 'truth models') rather than invest in full-field history matching exercises; it may drive us to understand the efficiency of EOR processes rather than model large scale stratigraphic architectures. The current interest in machine learning and AI tools may also fit into this approach. It depends what we need to understand in order to make the decision at hand.

Once some understanding is gained, it *may* lead to conventional full-field modelling studies; alternatively it may emerge that once a fundamental understanding of the question at hand is achieved, the asset team may be in a position to advise on a big decision without embarking on a time-consuming conventional modelling study.



NOTES:

Honest and critical thinking: how to make approximately accurate geological models, whilst avoiding being precisely wrong

Luke Johnson[1], Boyan K. Vakarelov, PhD[2]
[1]*Cognitive Geology*
[2]*Lead of WAVE Knowledgebase Project (Sedbase)*

The adage "all models are wrong, but some are useful" should be amended to "any **one model** is wrong, but **a suite of models** can be useful" when applied to geological modelling. Singular models **must** be assumed to wrong because (a) inherent inaccuracies and imprecisions in oilfield input data are difficult to incorporate in the model building workflow, and (b) all models are in themselves tremendous simplifications of the real world.

Few (if any) oilfield data are truly sacrosanct. Wellbore positional surveys (particularly those acquired while drilling in deviated wells) carry inherent and potentially significant errors. Production data, mostly treated as gospel in history matching studies, is oft generated by allocating gathering station data to individual wells using sporadic individual well tests.

Our ability to honour geological scale complexity in models is also tremendously challenged. We ignore areal upscaling of well data; despite wellbores representing a 1:125,000 sample rate of a typical grid cell. Structural models simplify faults into simple planes of dislocation, rather than zones of deformation, with complex 3D branching.

This paper explores how errors and simplifications can be managed in geological modelling workflows, specifically referencing how these challenges manifest in facies modelling concepts. It will be demonstrated that typical geological models in fact distribute 'facies assemblages' – and workflows for both facies model generation and downstream continuous property distributions must take this into account. Finally, the concept of how scenario management can take individually coherent realisations into ensembles of plausible outcomes can be used to deliver a business-decision-orientated workflow, focused on the Value of Information, rather than technical best-guesses.

NOTES:

Multi-scenario modelling for Cambo field development planning, UK West of Shetlands

Noah Jaffey[1], Katie Overshott[2], Christian Ellis[2], Ian Barron[1], John Martin[3], Kevin Purvis[2], Greg Stone[1]

[1]*Shell UK Ltd.*
[2]*Siccar Point Energy Ltd.*
[3]*Shell Exploration & Production, Houston*

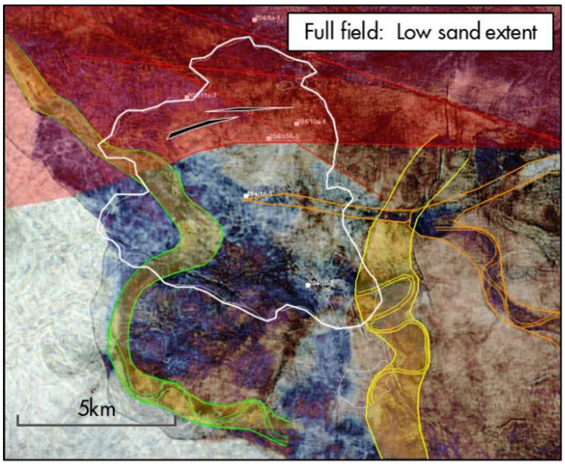
The H50 Hildasay reservoir of the Cambo field was deposited at the south-western paleo-coastline of the Faroe-Shetland Basin during the Early Eocene. Depositional facies vary across the field including a northern flank dominated by shoreface/mouthbar and a southern flank dominated by fluvial-estuarine channel belts and floodplain. These depositional features are clearly imaged in seismic attribute maps and some have been penetrated by the existing 6 E&A wells. The connectivity of the northern part of the reservoir has been appraised by a horizontal well production test. Despite extensive appraisal by a number of operators since discovery in 2002, the nature of these paralic deposits means uncertainty remains on reservoir spatial extent and connectivity which impacts development strategy and production profile range under waterflood development.

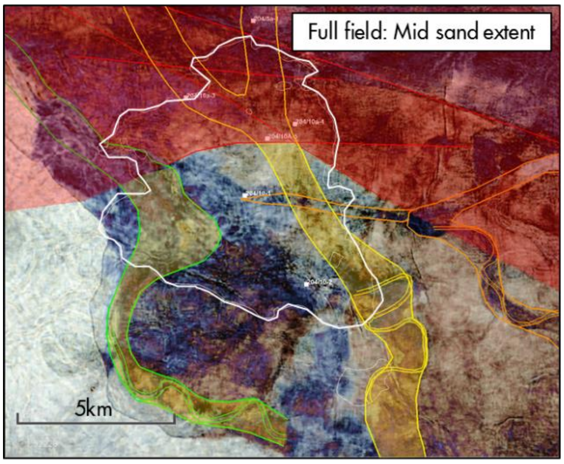
Pre-sanction, the ranges of these uncertainties have been captured in static and dynamic models by building different deterministic subsurface realisations of sand presence combined with probabilistic uncertainty of other subsurface parameters.

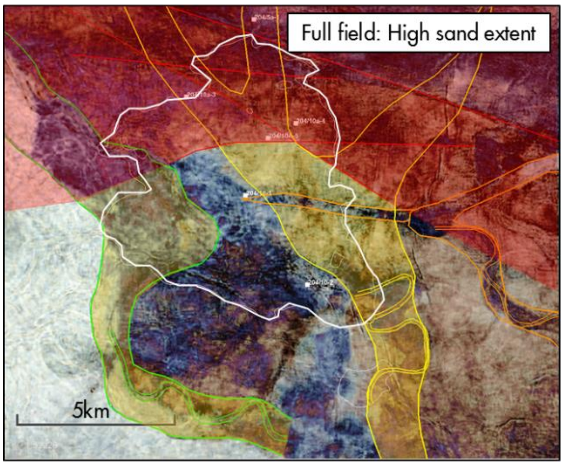
This presentation will focus on uncertainties in channel belt location, dimensions and internal connectivity, and why a multi-scenario approach is preferred to cover the uncertainty space rather than stochastic fluctuation around a reference case.

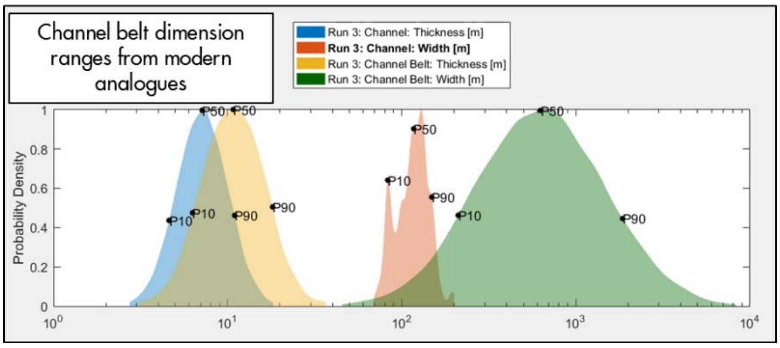
At the full field scale, alternative realisations of channel belt width, thickness and location were used. Ranges in these parameters were constrained by comparing the interpreted geometries of channel belt boundaries and abandonment channel fills with those from a worldwide database of modern analogue geometries. This enables a consistency check for predicted ranges of channel belt and channel story thickness and net-to-gross.

Multi-scenario modelling has been effective at capturing pre-production ranges in the highest impacting parameters for oil recovery in the Cambo field.


Full field: Low sand extent
5km


Full field: Mid sand extent
5km


Full field: High sand extent
5km


Channel belt dimension ranges from modern analogues
Run 3: Channel: Thickness [m]
Run 3: Channel: Width [m]
Run 3: Channel Belt: Thickness [m]
Run 3: Channel Belt: Width [m]
Probability Density
P10
P50
P90

NOTES:

Rapid Reservoir Modelling: Prototyping of reservoir geoscience and development concepts using sketch-based interface and modelling

Jackson, M.D.[1], Pataki, M.[1], Jacquemyn, C.[1], Hampson, G.J.[1], Machado Silva, J.D.[2], De Carvalho, F.[2], Coda Marques, C.[2], Costa Sousa, M.[2] and Geiger, S.[3]

[1]*Imperial College London*
[2]*University of Calgary, Canada.*
[3]*Heriot Watt University, Edinburgh*

Prototyping of design concepts is common in computer aided design (CAD) and computational fluid dynamics (CFD). Subsurface reservoir modelling is an example of CAD for CFD. Given the sparsity of data and complex nature of the reservoir systems of interest, there is often significant uncertainty around reservoir geoscience and reservoir development concepts. Prototyping of reservoir concepts prior to, or in parallel with, development of detailed models could add significant value. However, prototyping is rarely, if ever, undertaken. Rather, detailed modelling is the default, with uncertainty typically tested around a single reservoir concept.

Conventional reservoir modeling workflows are poorly suited to rapid prototyping of reservoir model concepts, and testing of how these concepts might impact on reservoir behavior. An alternative and complementary approach to traditional workflows is to use sketch-based interfaces and modeling (SBIM) to allow rapid creation of prototype reservoir models. SBIM is a simple and intuitive approach for creating complex 3D geometries that has been adopted in a number of CAD fields but is only now being applied to reservoir modeling. In SBIM, the user sketches lines in map or cross-section view that are automatically extrapolated to create parameterised 3D surfaces. The extrapolation can be driven by an underlying conceptual model and/or be constrained by data or further sketched lines.

We demonstrate here the geoscience prototyping CAD software Rapid Reservoir Modeling (RRM). In RRM, geologic heterogeneities are sketched to form a 3D geological model. Sketched surfaces bound volumes which can be meshed to perform rapid calculation of key reservoir properties. The speed and ease of use of RRM enables qualitative and quantitative testing of multiple concepts, developed from limited data, in order of minutes to hours. The sketched models allow uncertainty to be readily appraised, and models to be easily updated to incorporate new data or concepts.

We demonstrate application of the RRM technique to scenario testing. Starting with an initial dataset, we present a range of potential interpretations. We then create models of these interpretations in RRM, mesh and flow simulate them to estimate the variation in some key reservoir properties such as effective permeability or oil-in-place across our different interpretations and concepts. The models are simple but quick to make and analyse, and it is easy to vary the properties assigned to different facies/rocks/heterogeneities. We can therefore test both the effect of different conceptual models as well as the impact of varied reservoir quality.

NOTES:

AI based property modelling calibrated by forward sediment simulation

Colin Daly & Leigh Truelove
Schlumberger Ltd

Traditional approaches for distributing properties throughout a geocellular reservoir model have largely been focused around the use of Gaussian Simulation, Kriging and Object based modelling. These model-based methodologies have become the standard but the results they generate are only as accurate as the data used to condition them. Typically, geocellular models are generated primarily from well-based data (upscaled to the grid cells) which is then distributed throughout the model. Using data from drilled wells is intrinsically biased as these wells are often drilled in locations likely to yield favourable E&P potential; making the data recorded down the wellbore automatically skewed. Furthermore, once this data is incorporated into a geomodel, the standard methodologies can generate poor estimations of reality; i.e. Gaussian simulation assumes that the true distribution of porosity is stationary (or can be transformed to stationary easily), whereas co-simulation assumes that the correlation between primary and secondary variable is stationary. These situations are almost never the case. Ideally, geomodels would be constructed using data that was representative of the geology in the target of interest; meaning that all trends in the subsurface would be correctly estimated. This can allow property modelling methods to fully encompass these trends and generate more correct models.

Here we consider a methodology which incorporates the use of forward sediment modelling along with an ensemble based, machine learning property modelling algorithm.

The ensemble based, machine learning methodology can work with multiple input data types to predict an output variable; i.e. using multiple seismic attributes to help estimate porosity. It does so by evaluating the best combination of variables for an optimal estimate at each location. This is done locally so that the usual hypotheses of spatial stationarity is not needed.

However, it is often the case that the original model contains valuable spatial information that is not available to the standard machine learning algorithms. To incorporate this, the ensemble-based approach has been modified to ‘embed’ the geostatistical models within it. This means the model’s predictive ability is assessed as well as all the input data types (data and model’s respective influence may be weighted differently at different locations depending on the local predictive ability). The resulting improved model appears to be better than either classic geostatistical methods or machine learning methods alone.

By incorporating results of sediment deposition in basins with the use of forward modelling we generate a suite of data that characterises the ‘known’ trend. This data is further adapted to reflect a likely set of drilled well locations within a basin (based on any given drilling strategy). As a result, this dual set of data allows us to test the robustness of the ensemble-based machine learning approach.

The new ensemble-based methodology allows us to make far more accurate predictions for non-linear problems that are not at all robust to the stringent spatial stationarity hypothesis in the classic approach (e.g find sands which have high porosity with a probability of at least 0.8). The method may be adaptable to other situations where models would profitably be combined with ML techniques.

NOTES:

Geostatistics and data mining from digital outcrop models for reducing uncertainty in subsurface reservoirs

David Hodgetts
University of Manchester

In this presentation I will show how automated techniques may be applied for extracting geostatistical data from digital outcrop data in a more automated manner, and how that data may then be analysed using data mining and AI approaches. Digital outcrop models contain a huge amount of geoscientific information which is traditionally time consuming to extract. The development of new tools and approaches for working with outcrop data have resulted in increasingly large datasets which provide their own challenges for working with effectively. There are an increasing number of automated extraction approaches being developed with varying degrees of success, including neural networks, smart swarms and graph analytics.

Graph analytics is the study of how to analyse data that can be represented as a graph network. A graph network is essentially a set of vertices joined together by connections or edges, with the edges representing the relationship between those vertices. A digital outcrop model can be thought of as a graph network. Viewing the outcrop model in this way allows us to use a range of existing algorithms from graph theory to assist with mapping and segmentation.

A minimum spanning tree is a graph network without cycles (vertices which can loop back on themselves) which also minimises the edge weights on the graph. By constructing a minimum spanning tree based on different weights (for example based on, or a combination of, distance, orientation, colour or co-planarity attributes) and then sub-dividing that tree, the dataset may be effectively and rapidly segmented based on that attribute. This approach can be applied to extracting planar features from the outcrop model.

Smart swarm or ant colony optimisation algorithms have been applied to a variety of datatypes in and outside of the geological sciences. These techniques rely on using a swarm of agents which traverse the dataset (in this case a graph network) and lay down trails for other agents to follow, similar in the manner to how ants navigate to new food sources. This approach can be used to highlight and map subtle features which are not always visible easily in the digital model. The algorithm can be easily modified to map different features such as discontinuities (faults, fractures and bedding planes) and drainage networks.

By using automated approaches, with careful care to check the quality of the results, we are able to produce datasets with a higher degree of statistical significance, which in turn can be used to identify key relationships which can then be used in subsurface modelling, even if the statistics themselves cannot.

NOTES:

Machine Learning Methodologies Provide New Insights into the Reservoir in Seismic Interpretation

Lorena Guerra and Bruno de Ribet
Emerson Automation Solutions

Introduction

Uncertainty is an intrinsic property of the oil and gas industry, and the goal in any interpretation project is to reduce it to the minimum. One of the most effective ways to do that is to work in an integrated fashion using as much of the available data as possible.

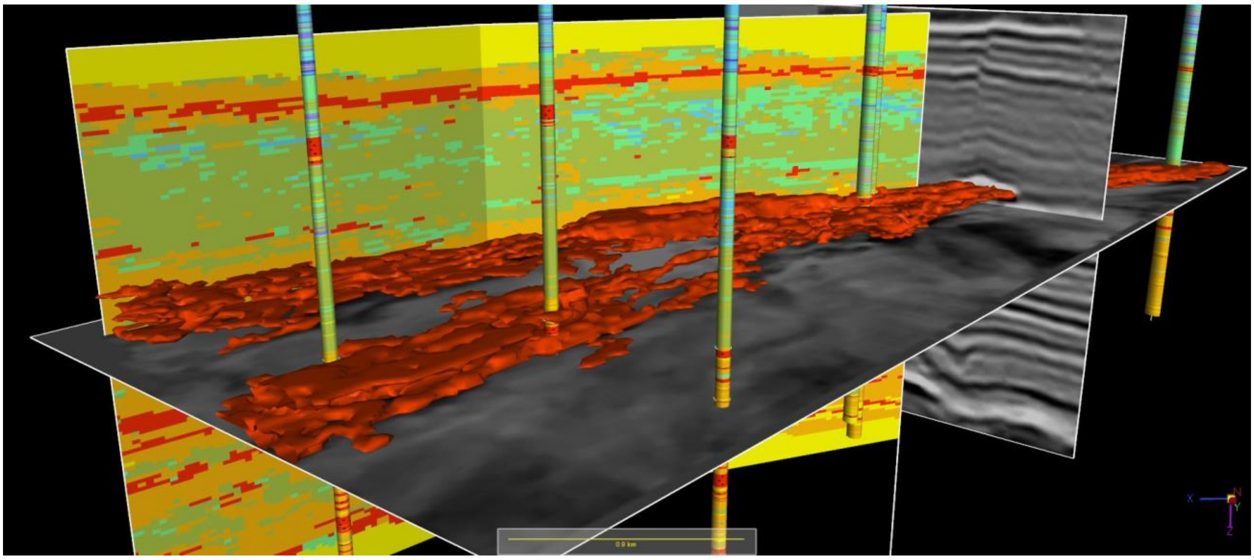
With the huge amounts of subsurface data available to interpreters (well logs, core samples, prestack and poststack seismic data, multiple attributes, etc.), it is virtually impossible for the human mind to integrate and extract all the available information in a timely manner.
The use of statistical tools to help extract information from vast amounts of data is not new. In recent years, however, this methodology has surpassed anything we could have imagined, due to the growth of the Internet and social media. The Big Data analytical tools that are available to us today enable the handling of huge amounts of data, at unprecedented speed.
Predictive analytics are now used in many fields as forecasting tools to accelerate decision-making and ramp up performance. Several innovative predictive methods are applicable to the challenges of oil and gas exploration and production. These include deep learning and other machine learning methods that can enrich subsurface models. This presentation discusses an effective approach for resolving reservoir facies heterogeneities, and discusses its applicability to different geologic settings.

Integrated analysis using neural networks reduces uncertainty

To evaluate the quality of a reservoir and gain a more realistic assessment of its behavior, geoscientists try to achieve accurate facies distribution mapping. The confidence in the facies distribution is linked to the amount of relevant data used for the analysis.
A standard approach to understanding reservoir quality is to perform seismic inversion to predict elastic properties. This solution however, may suffer from a non-uniqueness problem and it may be difficult to separate different facies. This is because reservoir quality is not linearly correlated with seismic data, which needs the introduction of uncertainty measurements.
The true integration of well and seismic data has always been a challenge due to their different responses and resolutions. To resolve these ambiguities, evolving machine learning methods are changing the applicability of seismic data from an exploration context to that of prospect development. This supervised approach delivers the most probable facies and probability associated with each facies. The strength of this method is based on the system's ability to integrate data of different types (core, wireline and seismic).
The initial phase in this method uses facies logs constructed from well data as the main source for describing the quality of the reservoir in terms of lithology, hydrocarbon saturation or rock type. In this sequence, another machine learning method, called Multi-Resolution Graphic Clustering (MRGC) is used. This method defines clusters of different resolutions, helping to differentiate between homogeneous and laminated geologic contexts.

The goal is to generate a probabilistic facies model from the seismic data. An association of naïve neural networks, each with a different learning strategy, is run simultaneously as an associative combination to predict facies. By running multiple different neural networks, we avoid biasing any of the neural network architectures. To train the neural networks, facies at the well and seismic data extracted along the wellbore in the interval of interest are used as input data. These are considered to be the hard training dataset. A major benefit of this technology is its ability to combine the full dimensionality of the prestack data, which carry more information, with any type of seismic attributes.
A second phase is to introduce seismic data away from the borehole (soft data). The neural networks "vote" on their integration to improve the final training dataset, before the ultimate learning stage. Adding "soft data" avoids overlearning from a limited dataset.
The last step is to propagate the final neural network model on the full seismic dataset, to generate probabilistic facies models composed of different volumes: the most probable facies (below figure), maximum probability for all

facies, and probability for each facies. Analysis of the facies and associated probability distribution introduces valuable insights into prospect uncertainties and seismic data reliability for prediction.



Geobody of reservoir facies on time slice, displayed with facies log along wellbore, predicted facies and full stack sections.

The question is no longer whether machine learning will benefit our industry. Rather, it is how, how much and how soon? Machine learning techniques are available today to accelerate interpretation and reservoir characterization processes and account for more data when working on a prospect. In many cases, they provide faster images of the subsurface while still maintaining accuracy, to help improve the decision-making process.

NOTES:

Modelling and Simulation of Heterogeneous and Anisotropic Reservoirs using a Fractal Approach

Paul W.J. Glover, Piroska Lorinczi, Saud Al-Zainaldin, Hassan Al-Ramadhan, George Daniel, Saddam Sinan
University of Leeds

Paradigms are shifting in the hydrocarbon industry: large, relatively uncomplicated reservoirs are obsolescent, while newly discovered resources will be increasingly smaller, deeper, more difficult to access, more heterogeneous and more anisotropic. This increasing complexity represents a challenge which must be met with an insufficient global supply of petrophysicists and reservoir modelling techniques more suited to large homogeneous reservoirs.

This presentation concentrates on the optimisation of production from heterogeneous and anisotropic reservoirs. Heterogeneity and anisotropy remain a challenge for the modern hydrocarbon industry because such reservoirs exhibit extreme inter-well variability making them very hard to model. Ironically, in heterogeneous and anisotropic reservoirs, such models are indispensable for reservoir management and development.

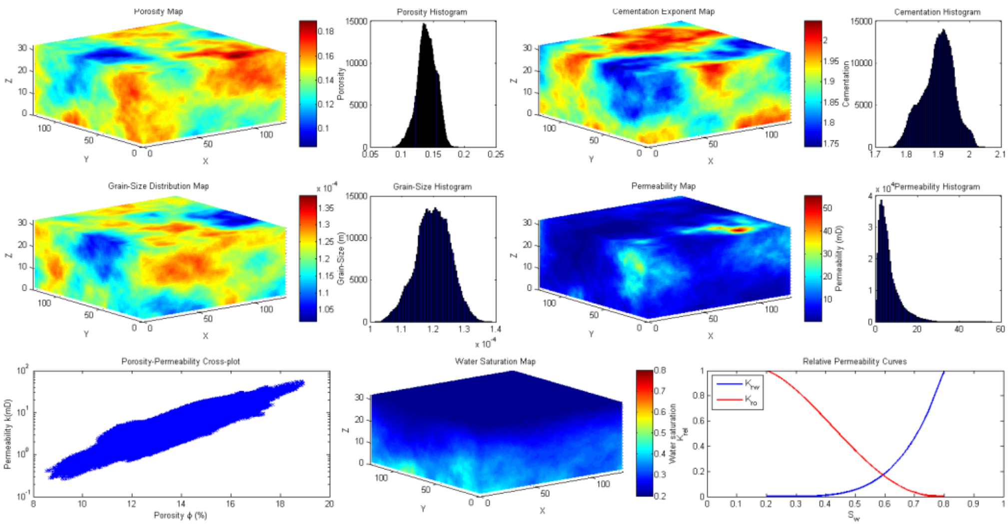


Figure 1. A reservoir model under test (Reservoir-5T), representing a fine-grained tight reservoir with low porosity and permeability; fractal dimension $\boldsymbol{D}$ =3.1 and a vertical anisotropy factor of χ=1.0. (128×128×32; 524288 voxels).

The conventional approach to constructing reservoir models uses modern statistical techniques to interpolate between wells that are constrained by 3-D seismic data. Such techniques invariably involve the analysis of inter-well variability and applied this to some krigged interpolation where the interpolated points are partially constrained by Sequential Gaussian Simulation (SGS), Sequential Indicator Simulation (SIS), or Bayesian Indicator Simulation (BIS), and may invoke the use of cloud transforms. All of these techniques assume that any controlled significant variability in the reservoir occurs only at scales larger than the inter-well spacing. While this was often true for large and homogeneous reservoirs, it is unfortunately not true for the heterogeneous and anisotropic reservoirs encountered in modern petroleum exploration. Such heterogeneous reservoirs often contain significant variability at scales both less than the inter-well spacing and smaller than the seismic resolution.

This presentation focusses on the modelling and simulation of heterogeneous and anisotropic reservoirs using a new fractal approach, which includes data at all scales such that it can represent the heterogeneity of the reservoir correctly at each scale. These three-dimensional Advanced Fractal Reservoir Models (AFRMs) can be used in generic modelling in order to understand the effects of heterogeneity and anisotropy, and can also be conditioned to represent real reservoirs.

This presentation will show (i) how 3D AFRMs, such as that shown in Figure 1, can be constructed and normalised to represent porosity, cementation exponent and grain size, and (ii) how these models can be used to calculate permeability, synthetic poro-perm cross-plots, water saturation maps and relative permeability curves. Finally, (iii) it will show how these initially generic models can be conditioned to represent the variability found in real reservoirs.

Results from the dynamic simulation of generic AFRM models show how total hydrocarbon production, hydrocarbon production rate, water cut and the time to water breakthrough all depend strongly both on the heterogeneity of the reservoir, as represented by the fractal dimension the reservoir, and also upon its anisotropy. Further work examining the effect of well placement shows that in heterogeneous reservoirs, the best production data is obtained from placing both injectors and producers, counterintuitively, in the most permeable areas of the reservoir, which is the opposite of conventional best practice. In addition, modelling with different degrees and directions of anisotropy have also shown how the hydrocarbon and water production depends on anisotropy and evolves over the lifetime of the reservoir.

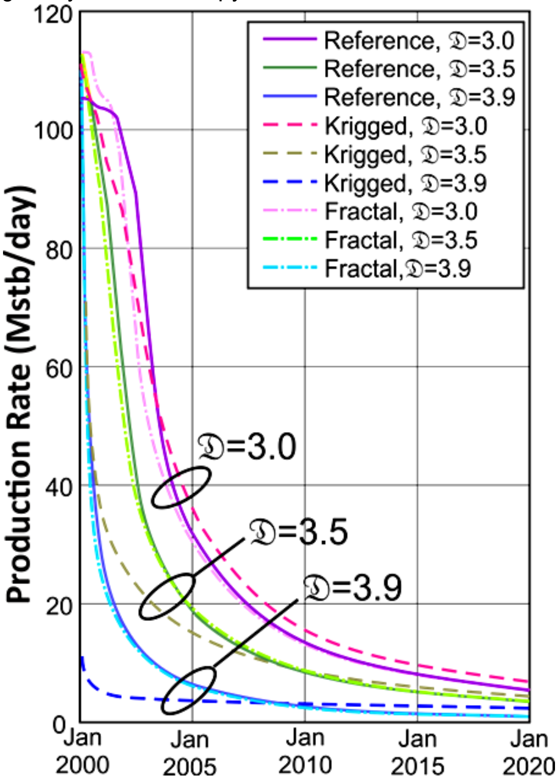


Figure 2. Comparison of the oil production rate as a function of time for reservoirs with 3 different degrees of heterogeneity, comparing the ideal (reference) case, the result of conventional krigging, and the results of the new fractal interpolation conditioning.

The real test of AFRMs is their capacity to be conditioned to real reservoirs. Initial results will be presented where fractal interpolation has been used to match AFRMs to reservoir data across a wide scale range. Results comparing the production characteristics of such an approach to a conventional krigging and up-scaling approach will be presented, showing a remarkable improvement in production modelling when AFRMs are used. The use of AFRMs in moderate to high heterogeneity reservoirs was always within 5% of the reference case, while the conventional approach often resulted in systematic underestimations of production rate by over 70%, as shown in Figure 2.

In summary, we believe that advanced fractal modelling of reservoirs has the potential to incorporate variability in the reservoir at all scales, not just at the scales above the inter-well spacing as is currently the case with conventional geostatistical approaches. Furthermore, such modelling is extremely important because initial tests, both generic and conditioned, are beginning to show that the consequences of not taking reservoir heterogeneity and anisotropy into account are extremely substantial not only for the amount and rate of hydrocarbon production but also for the lifetime of the field.

Reference. Al-Zainaldin, S., Glover, P.W.J. and Lorinczi, P., 2016. Synthetic Fractal Modelling of Heterogeneous and Anisotropic Reservoirs for Use in Simulation Studies: Implications on Their Hydrocarbon Recovery Prediction. Transport in Porous Media, in press, pp. 1-32.

NOTES:

A methodology for differentiation of facies in the heterolithic Triassic of Culzean

Duncan Chedburn, **John Banks**
TOTAL E&P UK Ltd

The UKCS Culzean uHPHT gas development project while on production plateau is expected to supply circa 5% of UK domestic gas consumption. The primary reservoir in the Culzean field is the Triassic Joanne Sandstone Member which, through the use of core and petrophysical logs, has been modelled within the static and dynamic domains. This presentation focuses on the challenges of modelling the facies of the Joanne given its heterolithic nature at the micro and macro scale in the static model. The challenge is compounded due to the restricted number of petrophysical logs that can be acquired in uHPHT wells. This results in the model being under determined. Facies is one of the key drivers of reservoir quality in the Skagerrak, therefore it is critical for predicting reservoir performance to have a robust facies scheme.

The presentation will demonstrate that integrated problem solving between subsurface disciplines is key to success. Data and knowledge from offset fields, core data and petrophysical logs was used to build and test a subsurface model. A simple yet convincing schema for predicting facies in the Joanne Sandstone Member is shown as an example of this integration. As the objective of the modelling was ultimately simulation and prediction of field performance it was critical to capture the geological heterogeneity associated with the facies in the geomodel, as it affects the vertical and lateral connectivity of the system.

NOTES:

A hierarchical workflow conditioning facies models to well data and realistic connectivity.

Deirdre Walsh[1,2], Tom Manzocchi[1,2]
[1]*iCRAG (Irish Centre for Research in Applied Geosciences), University College Dublin*
[2]*Fault Analysis Group, School of Earth Sciences, University College Dublin*

Conventional geostatistical modelling including variogram-based methods, object-based modelling and pixel-based multiple point statistics (MPS) methods are unable to generate models with low connectivity at high net:gross ratios. The connectivity of facies in these geomodels inevitably increases sharply at a net:gross ratio of about 27%, which is the percolation threshold of systems of randomly distributed 3D objects. At net:gross ratios of 40% or greater, most objects are interconnected to all other objects in the models, resulting in predictions of relatively high sweep efficiencies for such reservoirs. This contrast with observations of natural deep-water depositional systems, where non-randomness such as compensational stacking results in many geological systems that are poorly connected even at high net:gross ratios and which therefore have lower sweep efficiencies than the geomodel. It is therefore important if we are to improve predictions of reservoir performance, that the correct degree of object connectivity is incorporated into reservoir geomodels to realistically represent the heterogeneity present.

A workflow has been developed allowing the creation of low connectivity facies models conditioned to well data. The method combines a relatively new technique (the compression algorithm) with multiple-point statistics simulation. In this work, the amalgamation ratio of the net facies is used as a measure of connectivity. Amalgamation ratio is defined as the proportion of object bases that erode into or amalgamate with an underlying object. In conventional models the amalgamation ratio is equal to the net:gross ratio, but in natural systems it is often much lower. The compression algorithm permits the generation of an object-based model with user-defined and independent values of amalgamation and net:gross ratios: these provide the training image for the method (Fig 1a). Both the training image and the conditioning wells are transformed (“decompressed”) to a volume with equal amalgamation and net:gross ratio (Fig 1b). After creating a multiple-point statistics model using these constraining data (Fig 1c), the inverse transformation is applied, resulting in a final facies model which recreates the connectivity characteristics of the training image at the correct net:gross ratio and honours the well data (Fig 1d).

Although Fig 1 shows a single scale model, the method operates within a hierarchical sedimentological framework by using multiple decompressed training images. This approach is consistent with recent studies focused on understanding the internal architecture of deep-water lobe systems that has recognized a general four-fold hierarchical geometrical arrangement of lobe complex, lobes, lobe elements and beds for these reservoirs. This hierarchy is based on the characteristics of the fine-grained units that bound the sand prone bodies. Hierarchical fine-grained units act as key flow barriers and baffles and can lead to complex compartmentalisation, impacting reservoir connectivity and overall recovery. This workflow has been applied using multiple conditioning wells in a producing oil-field (Fig 2).

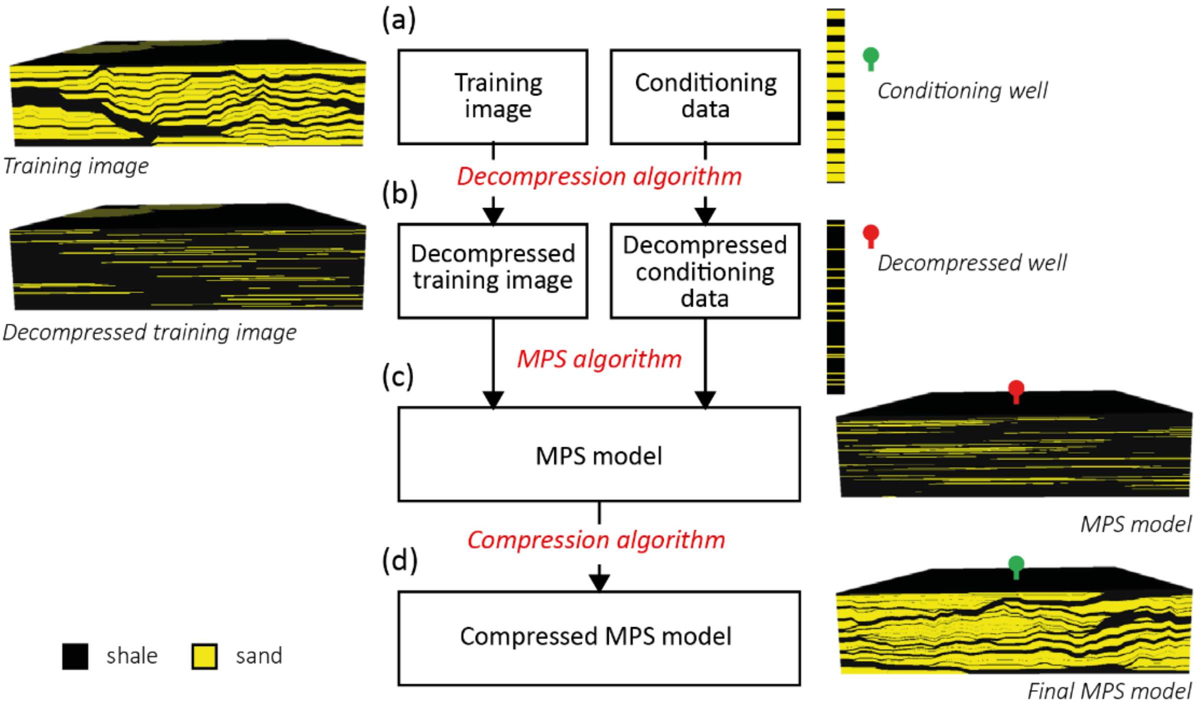


Figure 1. Summary of the new workflow that has been developed to generate MPS models with low connectivity at high net:gross ratios capable of honouring well data.

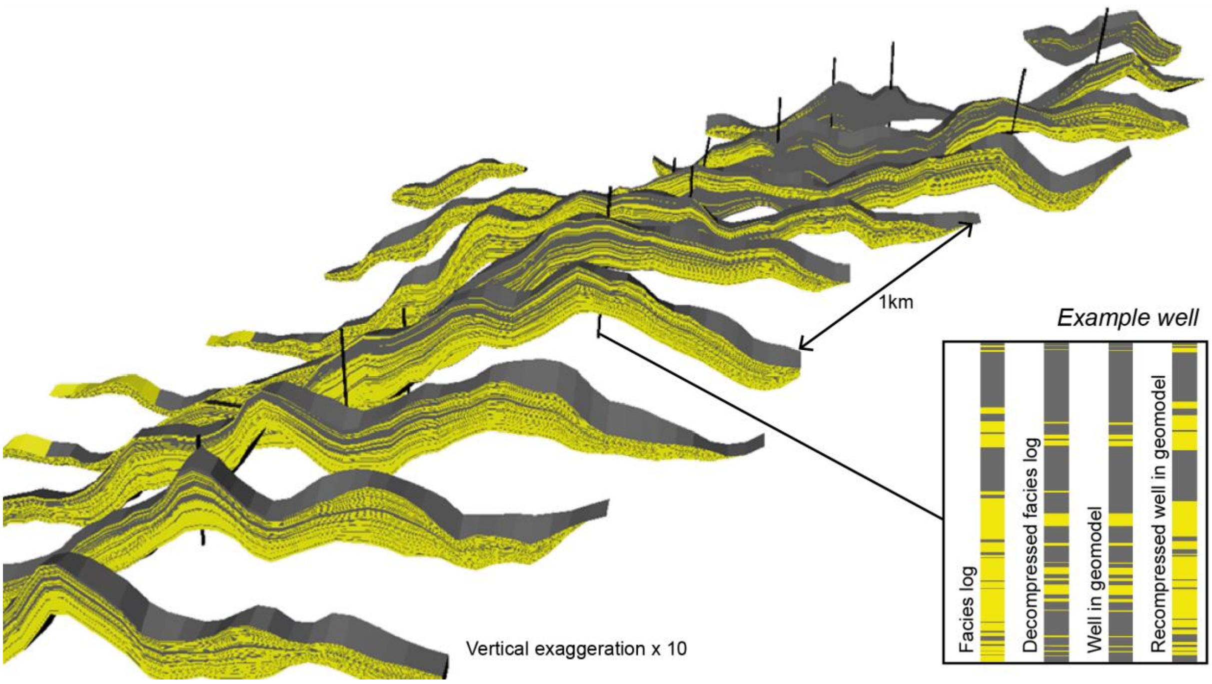


Figure 2. An example of a reservoir scale geomodel of a producing oil field built using the decompression workflow conditioned to a number of wells.

This publication has emanated from research supported in part by a research grant from Science Foundation Ireland (SFI) under Grant Number 13/RC/2092 and is co-funded under the European Regional Development Fund and by PIPCO RSG and its member companies.

NOTES:

Leveraging regional geology and conceptual models at the field and reservoir scale: building more reliable earth models under sparse data conditions

Kate C.S. Evans[1], Jeffrey M. Yarus[1], Elham Mohsenian[1], Jose Montero[1], Jiazuo Zhang[1]
[1] *Halliburton, Houston*

Facies interpretations are key inputs into 3D petroleum systems models (PSM); they form the basis for modeling calculations and are integral to understanding both conventional and unconventional reservoirs. Building facies models is a time-consuming process, involving lengthy petrophysical evaluation. Difficulties arise when data are temporally and spatially inconsistent. By using machine learning (ML) algorithms, geostatistical modeling, and conceptual models, it is possible to build predictive facies models at any scale.

Obtaining reliable models is vital, but difficult, particularly in the presence of sparse data. We address the construction of reliable reservoir models by leveraging conceptual models and depositional processes at the basin scale. This geological understanding underpins the physics, chemo-mechanical, and mechanical interactions at local scales, and enables better prediction, interpolation, and simulation. We demonstrate how understanding facies at the basin scale, coupled with ML and geostatistics, can be used to supplement otherwise sparse data and successfully build reliable reservoir models. For reservoir characterization, facies are pertinent to understand the distribution of properties and, for unconventional reservoirs, for choosing the correct stimulation strategies.

A set of logs from the Permian Basin are manually interpreted to understand facies and then used as a training set for ML algorithms to define facies over a larger set of logs. Results are verified using regional geological understanding. Traditional earth modeling techniques, combined with the guidance of conceptual geological models, are then used to build a basin scale facies model. Subsequently, a 3D PSM is built to capture the physics, chemistry, and geomechanics. The facies and PSM can be downscaled and recalibrated at a local project level using local data. However, where sparse data occur, variables calculated from the local PSM are used as co-variables in a geostatistical simulation to reduce uncertainty.

3D basin facies models, PSM, and geostatistics have been used to constrain critical properties at the local reservoir scale to produce reliable models. ML algorithms have been used to interpret facies from petrophysical logs. The final model forms the basis for revealing much subsurface insight and shows how unconventional reservoir characterization can be performed more effectively in the presence of sparse data. Here, key reservoir properties, such as brittleness, maturity, porosity, pressure, and organic enrichment often unavailable from local data, can be calculated.

Although some of the methods described are not new to reservoir development, the application of building a quantitative scalable model from the basin to reservoir, or even the well, is novel. Further, many reservoir data sets lack well density and key modeling variables to build models and reduce uncertainly. The technology presented here demonstrates that information derived at the basin scale, beginning with the distribution of geologic facies, can be rescaled and calibrated to reduce these problems.

NOTES:

Day Two:

Dynamic and Static Modelling

Uncertainty: Battling our Bias Demons

Greg Stone
Shell UK

Extensive functionality exists in Geomodelling software to represent geology in increasing detail, and the temptation exists to be ever more precise with geomodels. However, this can drive Intelligence Bias resulting in predictions being “precisely wrong”.

This presentation will focus on the importance of understanding geological uncertainty prior to detailed modelling, focussing on the following elements:

- Battling our bias demons; how good are we at defining uncertainty and what are the typical human biases which can hinder us.
- The need to embrace the reality that we don’t know it all; approaches to overcome our inherent bias.
- Approaches for managing uncertainty; pros and cons of applying uncertainty around an anchor point vs multi-scenario approaches.
- Living with uncertainty; linking development strategy to subsurface uncertainty to protect projects against downside reservoir outcomes, whilst still being able to sanction projects with our “eyes wide open” to geological uncertainty.

NOTES:

"What's inside the Loop?"

David Cox[1]**,** Matthew Le Good[2]
BP Exploration Operating Company Ltd, Aberdeen
BP Exploration Sunbury, Sunbury-on-Thames.

The Schiehallion subsea development is one of the largest on the United Kingdom Continental shelf. The development comprises two fields; Schiehallion and Loyal, which are located approximately 200km west of the Shetland Islands in water depths of 300-500m.

The Schiehallion Field was discovered in late 1993 by wells 204/20-1 and 204/20-1Z. The combined development has a STOIIP of >2.3 billion barrels, developed under waterflood. Oil is contained in deep-water turbidite reservoir sandstones of Palaeocene T25 to T34 age with a combined structural-stratigraphic trap. The development was sanctioned in 1996 with oil production commencing in July 1998 and continuing until 2013 when the field was shut-in for redevelopment. After an extended shut-in the Schiehallion Field was brought back online in 2017, through the new Glen Lyon FPSO production facilities.

The ongoing redevelopment programme commenced in April 2015, has drilled and completed 19 wells to date, and is expected to continue for several more years. The campaign includes new producer-injector pairs and standalone wells to supplement and support existing well-stock. The wells, target stacked turbidite reservoir intervals, comprising the youngest T35/T34 interval, the main producing T31 interval, and the previously under-developed T28/T25 fairway.

The modelling challenge has always been to integrate seismic, log and core data at an appropriate scale in the model. There is a requirement to represent the variability and distribution of net reservoir (critical heterogeneity) that will impact fluid distribution and dynamic behaviour after production start-up. Seismic data provide the only available spatial dataset that can inform the depositional elements and architecture away from well control. However, in the past there was an over reliance on seismic data alone to describe the container fill as it has imaging limitations, and a failure to augment the geophysical description with a plausible geological concept.

We present an example of an integrated and updatable workflow to populate net in the Schiehallion static reservoir models, following the redevelopment drilling campaign, using One Dimensional Stochastic Inversion (ODiSI) combined with a plausible geological description from well data. The updated models should represent an integrated view of the subsurface, covering a range of uncertainties and will provide one of the tools for infill well planning to support the continued development of the Schiehallion Field until 2022 and beyond.

NOTES:

Petrophysical Uncertainty in Geomodels

Alan Johnson
Integrated Petrophysical Solutions Ltd – Aberdeen

Petrophysical Uncertainty can often be overlooked in geomodelling work because a) it is quite complex to quantify and b) because the levels of uncertainty are often assumed to be negligible in relation to the more obvious geological uncertainties involved. Moreover, it is often assumed that petrophysical uncertainties will be addressed within the geostatistical modelling process itself.

This talk will initially highlight two different types of uncertainties: statistical uncertainty, the level of which can be reduced by gathering more data e.g. drilling more wells, and systematic uncertainty, uncertainties in the analysis process which, when consistently applied in all the wells in the field, will remain constant, irrespective of the number of wells.

After a discussion on how the uncertainties in the key petrophysical parameters can be estimated, examples will be presented on how increasingly detailed levels of petrophysical analysis, and their associated increasing impact on manpower and cost, will be reflected in reducing levels of uncertainty.

The results of the above exercise can be used to inform the decision by the modelling team as to the appropriate level of analysis to be applied, depending on the objectives of the modelling work. For example, a multi-week petrophysical study would perhaps not be justified if only rough, indicative, volumes are required. Whereas, for an economic business decision relying on detailed dynamic modelling, individual single-well analyses would probably be inadequate.

NOTES:

Reducing uncertainty in reservoir models using structural modelling and analysis

Freya Marks, **Andrew Bladon,** Alan Vaughan, Cathal Reilly, Fiona McLean & Manoel Valcarcel
Petroleum Experts, Edinburgh

Models describing the geology of a reservoir provide a basis for making important economic decisions. However, uncertainty is associated with any geological model. This limitation is inherited by any analysis performed using the model, such as migration analysis, reserve estimates and production simulation. As such, reducing the impact of unknowns, as well as understanding the potential impact of these, is a critical part of the decision making process. Here we show using case studies how structural modelling and analysis using geological principles is a fast and effective method of reducing and characterizing factors that increase risk at all stages in the life of a reservoir model.

During the initial interpretation of data, structural modelling techniques (e.g. fault shape prediction and calculation of detachment depth) provide fast and simple approaches for supplementing incomplete or poor data. Application of appropriate techniques provide a means of developing geologically plausible structural frameworks around which an interpretation can be completed. Any remaining indeterminate factors can be characterized by developing multiple model scenarios which capture the range of possibilities and can be tested subsequently. Importantly, the use of techniques that are based on geometric rules and geological principles at the incipient stages of model development removes subjectivity in the interpretation of primary features and immediately reduces uncertainty and increases confidence. It is commonly at this early stage in the life-cycle of a reservoir model where uncertainty is greatest.

Interpretations and models developed from the data can be tested and validated to ensure the interpretation is geologically plausible. Validation techniques include geometric restoration and kinematic forward modelling. The progression of an interpretation and model from static, geometrical analysis into more dynamic analyses using kinematic techniques provides a method of challenging an interpretation and improving the understanding of structural evolution further. The improved understanding and validated model will have further reduced the impact of unknowns associated with the initial model.

It is only after a reservoir model has been tested, validated and the deformation mechanisms and history is understood that a model is ready for further analysis. Different model scenarios might be used to characterize possible variations in gross rock volume, a sequential restoration might be used to help predict structural architecture at key geological times, and deformation mechanisms might be modelled to predict strain distributions and fractures associated with structural evolution. Critically, each of these analyses are undertaken using a model that was developed in a way that makes the best possible use of data and interpretations and using scenarios that bracket a range of possibilities. The results of these analysis provide information used for making important economic decisions and improve confidence in the reservoir model.

NOTES:

Uncertainty Modelling: Moving away from the 'Base Case' central tendency bias

Smruti Ranjan Jena, David Olowoleru
Chrysaor

The quest to capture subsurface uncertainties associated with hydrocarbon accumulation and production have progressed a long way from basic map-based volume estimates to complex 3D multi- scenario model building. As the source of uncertainties range from basic data measurement to the static and dynamic behaviour of different subsurface processes, assessing uncertainty becomes key to reliable forecast models. Uncertainty analysis possesses two inherent problems, first- the very task of quantifying uncertainties, which are 'known unknowns' & 'unknown unknowns', second- evaluating and representing the variability.

Traditionally uncertainty analysis has been unidimensional and is often defined by the range of hydrocarbon in-place which subsequently generates a range of recoverable reserves. The spread of this range around the mid-case represents the variability and a tornado chart captures 'one-at-a-time' sensitivity of inputs to this variability. Things become complex when other dimensions e.g. reservoir heterogeneity, compartmentalization, structural uncertainty, connectivity/preferential flow directions, injector-producer sweep efficiency, different development concepts etc are added to the uncertainty analysis. Other than its limitation of being uni-dimensional, a major drawback for this traditional uncertainty analysis is the approximation of a 'central case' or the 'Base case'. When uncertainties are inherent to each aspects of the evaluation, assumption of a 'base case' introduces bias to the analysis.

An alternative approach to this is to assume several equiprobable scenarios instead of one 'base case' while building uncertainty models. Multiple scenarios also help to introduce other dimensions (heterogeneity, flow preferences, development concepts) to the uncertainty analysis. But, this approach has another issue – how to measure the variability? The data analysis technique MDS (Multi-dimensional scaling) is one of many solutions to quantify and represent the variability in such multidimensional analysis. The MDS algorithm works in two steps, in the first step, it checks for the differences between individual models and creates a distance matrix between them and the second step produces a two-dimensional scatterplot using a dimension reduction algorithm. The 2D MDS scatterplot then becomes a variability map of the models/scenarios, where similar models are clustered together.
The case study is based on the East Everest field, where an uncertainty modelling was carried out to understand the impact of reservoir heterogeneity and reservoir distribution on future infill wells (figure 1). Being a mature field with considerable production history, the remaining potential of the field is a combination of static, dynamic reservoir properties as well as the future well location and facility modifications. Rather than assuming a base case, a suit of equiprobable uncertainty models were built trying to capture the reservoir heterogeneity in the Maureen sandstones by varying facies variograms, depositional directions, various reservoir pinch-out & property distribution scenarios. To add to these static models several dynamic uncertainties e,g. relative permeability, Kv, Kh, etc were introduced. All the models were then assessed for various in-fill targets along with multiple facility modification scenarios to understand the remaining field potential. A simple to implement MDS workflow was created in Petrel/ Python to analyse the models. The MDS scatterplots helped to capture the distinctly different heterogeneous scenarios. This also highlighted the issues with data redundancy, i.e. that not all models in the suit of uncertainty models added value to the analysis. This uncertainty modelling approach was used for identification and planning of the highest-ranking future infill target(s).

Assuming a base case tends to centralize and narrows the uncertainty analysis. The multi-scenario uncertainty modelling with MDS data analysis is a more efficient tool to capture multi-dimensional uncertainties.

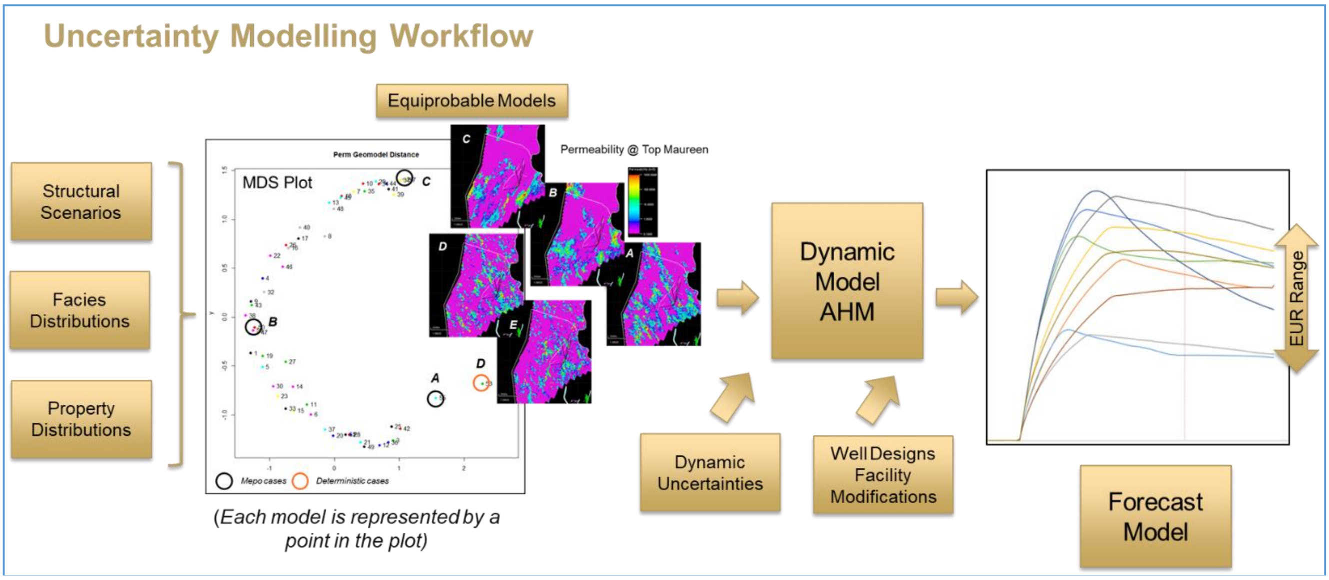


Figure 1. Uncertainty modelling workflow.

NOTES:

Integration of forward stratigraphic modeling with Interpreted and geostatistical data for building better predictive reservoir models

Sergio Courtade[1], David Marquez[1], Per Salomonsen[1], Daniel Tetzlaff[2], Jan Tveiten[1], Hong Nguyen Viet[1]
[1]*Schlumberger,*
[2]*Consultant*

Traditional reservoir modeling techniques are insufficient to describe reservoir geometry and properties distribution because they do not place geologic features according to their depositional geometry and because they are often limited in managing trends and continuity.

Forward stratigraphic modeling uses numerical simulations to model erosion, transport, and deposition of clastic sediments, as well as carbonate growth and redistribution. The resulting models show the geometry and composition of the stratigraphic sequence controlled by sea-level change, paleogeography, paleoclimate, tectonics, and variation in sediment input and they reproduce reservoir architectures and properties distribution in a more realistic way than traditional reservoir modeling techniques.

Conditioning these forward models to the well and seismic data for a specific dataset is possible but the computational effort makes impractical to honor all the details at the reservoir characterization scale. An alternative approach involves integrating the forward model and the interpreted data using geostatistical techniques.

This integration workflow comprises three main steps (Figure 1), conditioning of the forward modeling parameters to honor the well and seismic data, geometrical integration and property integration of model and data.

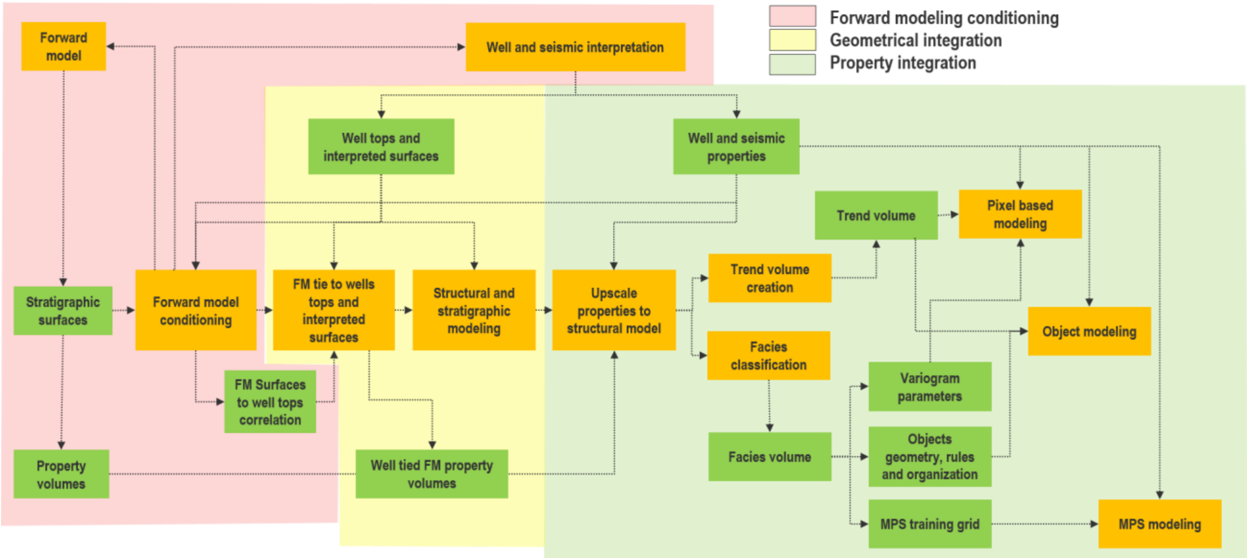


Figure 1, Workflow for the integration of a forward model and interpreted data, orange boxes represent processes, green boxes represent products or objects, workflow steps are represented as red (model conditioning), yellow (geometrical integration) and green (properties integration) background.

Forward model conditioning involves the optimization of the model inputs and parameters until the model honors specific controls (interval thickness, net to gross, stacking patterns, stratigraphic surfaces geometry) interpreted at wells and seismic data. One result of this conditioning is the correlation between the model stratigraphic surfaces and the well tops and seismic interpreted surfaces. This correlation allows to create a geometrical transformation that tie the model stratigraphic surfaces to the well tops and honors the model depositional framework and the interpreted well markers.

Several geostatistical workflows enable the integration of the forward model simulation results and the well measurements (Figure 1). One uses forward model properties as probability trend (surface or volume) for pixel based and object modeling algorithms; another classifies the forward model properties into facies and use them as input for MPS modeling or for extraction of geometrical and variogram parameters that are later used in object or voxel based modeling.

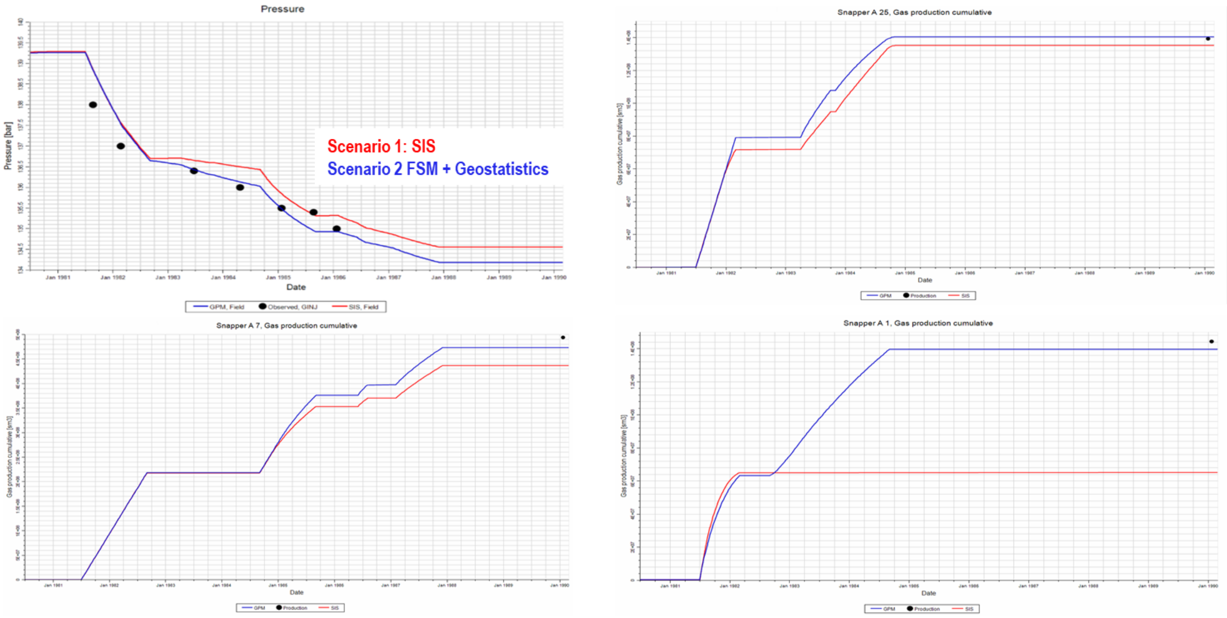


Figure 2 Snapper field (Gippsland Basin, Australia) pressure history (upper left) and gas production at three wells (lower left, upper and lower right), the blue line represents the production simulation results based on a geologic model integrating FSM in the geostatistical workflow, the red line represents the simulation results based on a geologic model populated using sequential indicator simulation over well data, black dots represent historic data.

Forward stratigraphic models reproduce reservoir geometries and features in a more realistic way than traditional geologic modeling techniques but honoring the input hard data require a strong effort in model conditioning. The techniques presented in this abstract allow for a smooth integration of forward models and hard data enabling more constrained and consequently better predictive reservoir models (Figure 2).

NOTES:

Reimagining History Matching in an Uncertainty Modelling Context

Martha Stunell
Resoptima

The traditional approach to building 3D reservoir models is due a radical change. This is because, as an industry, there is growing recognition that models often do not predict well, and in fact can be seriously wrong which results in costly and poor decisions. However, as soon as we openly admit that models are not instruments for seeing the future, how can we defend model building at all. Fundamentally, how can we make models “useful” even if we know they are “wrong”?

The answer to this is that by placing the model where it belongs in the decision-making framework and using it as a vehicle to express and explore uncertainty, it will be useful. This sounds simple, but unfortunately years of best practice, company standards and software technology development has created a modelling paradigm where experts and modelling practitioners create best technical cases or select a few models to try to capture the vastly uncertain geological context in which subsurface decisions are taken. Probably one of the most dangerous and mis-leading model building steps that we undertake is history matching, where we tend to over constrain inputs to match perfectly curves of data that we think represents how the model should perform. This ignores the fact that the model is a simplification of a complex system and model error needs to be acknowledged and used to capture a more realistic range of future behaviour.

We will present software tools, workflows, and case studies to illustrate the paradigm shift required to take history matching from its traditional context into a fundamental model uncertainty propagation step. This involves expressing uncertainty in the modelling inputs as an ensemble of models and allowing the production data to explain at least some of what you don’t know by transforming this ensemble into models which are constrained by this data. The approach of dynamic data assimilation really allows the production data to speak, and transforms the history matching exercise from one where engineers and decision makers put faith in perfectly matched curves to a process where accepting model error is natural and allows future performance to be more fully explored.

NOTES:

A Benchmark of Sensitivity Analysis Methods to assess the Dynamic Impact of Structural and Petrophysical Uncertainties

Gabriel Godefroy & Alan Irving
Total E&P UK, Geoscience Research Centre

Uncertainty is inherent to geological interpretation and modelling (e.g. Frodeman, 1995; Bond, 2015). In applied geology, uncertainty is quantified using statistical distributions of model parameters (e.g. uniform or normal), or sets of alternative discrete scenarios (e.g. sedimentological concepts; structural interpretations). Building several geological scenarios helps to reduce the risk of anchoring to a single model when making decisions (Bond et al., 2007). This process is referred to as uncertainty quantification or uncertainty modelling. The captured geological uncertainty is then propagated to one or more questions of interest, such as hydrocarbon volume estimations and production forecasts.

Sensitivity analysis is the study of how uncertainty in system output is apportioned to input uncertainty (e.g. Saltelli et al., 2008). It provides an understanding of the relationships between input and output variables, enhances communication between modellers and decision makers, and helps model simplification and calibration by focusing on the most influential parameters. While sensitivity analysis has been applied to geological uncertainty (e.g. Skorstad et al., 2008; Manzocchi et al., 2008), we are unaware of a benchmark of the various methods. Here, we discuss the application of three such methods to the dynamic impact of structural and petrophysical uncertainties, and highlight some challenges.

In the frame of reservoir engineering, numerical flow simulation is computationally intensive, limiting the number of models that can be run. Furthermore, the input parameters can be non-numerical (scenario or realization-based); the input space is high-dimensional, making exhaustive exploration impossible, and the flow simulation model is generally highly non-linear.

In this study, we use a synthetic faulted reservoir model, modelled using a commercial blackoil flow simulator. We represent uncertainties on horizon geometry using the Alea method (Charles et al., 2001) and fault throw using a proprietary code (Godefroy et al., 2019). Petrophysical uncertainty is assessed using geostatistical simulations of porosity and permeability fields. Nine realizations are simulated for each variable, leading to $9^4 = 6561$ possible models. Reservoir model building is usually time consuming and requires some manual inputs, in particular to construct grids and specify well connections. In Alea, geometrical perturbations are applied directly to grids, but the reservoir connectivity is constant so uncertainty may be underestimated. In this study, we vary fault throw and automate grid generation, which is possible only for simple models.

In monoparameter (or one-at-a-time) sensitivity analysis, each parameter is modified to minimum and maximum values while keeping all the others at the baseline. For the case described above, none of the parameter values can be considered as a baseline. Furthermore, this approach provides a very limited exploration of the parameter space, and neglects any parameter interactions, hence it is not considered further.

Parameter interactions can be evaluated using variance-based sensitivity analysis (Sobol, 2001) in which the variance of one output property is decomposed into fractions which can be attributed to input parameters or sets thereof. This can be applied to any number of models generated stochastically or using a planned exploration of the parameter space, also known as experimental design. The latter approach may provide a more efficient sampling for cases with many parameters, and results from sensitivity analysis (screening) designs can be partly re-used in modelling of proxies (response surfaces) for optimisation.

A limitation of the variance-based approach for flow simulation is the requirement to work with a single output. To overcome this, Fenwick et al. (2014) and Park et al. (2016) proposed to use distance-based generalized sensitivity analysis (DGSA), in which results are first placed into two or more discrete clusters (e.g. good and bad fit to historical data). Any parameter with the same distribution in different clusters is considered non-significant. The approach can integrate both discrete and continuous parameters, handles asymmetric parameters and interactions, and can use proxies provided they correctly classify models.

Using the case described above, we compare these approaches in terms of the required number of models, accuracy of the estimated sensitivities, ease of implementation and understanding results, and extension to parameter optimisation.

Sensitivity analysis is a tool to track the influence of parameter uncertainty on questions of interest, and thus guide the decision making process. Commercial geomodelling tools allow uncertainties on reservoir grid properties to be propagated to flow simulation and optimisation. Integrating structural uncertainty into this process necessitates automatic modelling of alternative scenarios. Sensitivity analysis on geological scenarios comprising large numbers of correlated variables requires dimension reduction and modelling choices.

The authors would like to thank Total E&P UK for permission to publish this work.

NOTES:

Lower Captain Sandstone: The Importance of Data Integration in Geocellular Modelling and History Matching

Karl Charvin, Anna Vitali, Florence Bacciotti
Chevron Upstream Europe

The Captain Field is an offshore heavy oil field located in Block 13/22a of the North Sea UK sector. Production started 20 years ago with long horizontal producers supported by horizontal water injectors. The acquisition of OBN (Ocean Bottom Node) data and plans to implement Chemical Enhanced Oil Recovery (EOR) in the field have triggered a comprehensive reservoir characterisation and history match revisit of the Lower Captain Sandstone (LCS). The LCS has been deposited by deep-water turbidite processes confined within a slope-valley system oriented NNW-SSE. Although the reservoir has high net-to-gross (>90%) and high permeabilities (>6 Darcies), the presence of faults and the cross-cutting nature of turbidite channel complexes cause significant heterogeneity.

The complexity of the LCS reservoir is highlighted by the observed flow behaviour. Early life wells displayed erratic breakthrough times and water cut development, indicating an uneven water front while later infill wells proved the presence of “water above oil”. Production Logging provided further indications of partial compartmentalisation within the reservoir as it proved the existence of cross-flow along some of the producing wells.

The paper focuses on the recent characterisation and history match of the Lower Captain Sandstone. It will highlight the imaging uplift from the OBN data on the turbidite channel geometry, the presence of faults and how this data has been used to improve the geo-cellular model. Despite the uplift, some key uncertainty remains, and the static model requires the use of stratigraphic concepts defined from the well logs, core, analogues data, production logging and pressure data to populate facies heterogeneities (such as basal debrites). More importantly, history matching and the study of predicted vs observed water cut evolution was fundamental in determining key baffles, fault permeability, aquifer size and overall reservoir connection. To encourage discussions between the reservoir engineer and the geologist, the modelling strategy was chosen to be simplistic and deterministic, with a focus on grid design and the ability to control the location of key heterogeneities. Capturing the flow behaviour appropriately was key, especially for Chemical EOR forecasting. Findings led the team to refresh the pre-conceived uncertainty list. Model uncertainty assessment will be later realised using a sensitivity approach.

NOTES:

Structural and Sedimentological controls on the performance of deeply buried aeolian gas reservoirs

Sophie Behrendsen[1], John Howell[1], Adrian Hartley[1], Holger Rieke[3], Colm S. Pierce[1,2]
[1] *University of Aberdeen*
[2] *CASP, Cambridge*
[3] *DEA, Deutsche Erdoel AG*

Deeply buried (>4km) aeolian reservoir targets including the German onshore Rotliegend exhibit an unconventional production history that is not representative of homogenous sand “tanks” that do not contain significant production-impacting heterogeneities. Although tight-gas production profiles are common in North Sea reservoirs, discrepancies between predicted static and reported dynamic volumes are significantly understudied. This tight or “slow” gas effect has historically been attributed to structural compartmentalization, however the effects of faulting are rarely observable at current seismic resolution or recorded at well.

Recent studies of internal dune characteristics have found a correlation between dune body dimensions and the ratio of grainfall to grainflow laminae together with the angle of dip (Mountey and Romain 2013). Therefore, this study uses the distribution of grainflow laminae within a dune as well as their angle of dip in core to estimate und model possible dune body dimensions and their spatial variation within a deeply buried aeolian reservoir.

Dune bedform geometries and small-scale heterogeneities such as different poroperm values caused by interbedded grainflow and grainfall laminae are suggested to have a significant influence on the reservoir’s performance as they react differently to compaction and diagenesis. Compaction causes a significantly higher porosity reduction in the finer grained grainfall laminae than in the coarser grainflow laminae. This leads to baffling of gas flow into flow compartments that permit a slow, but constant “background” production rate prevalent over long time periods, which is directly linked to changes in dune morphology and composition.

Improved understanding on the distribution, dimensions and reservoir quality of different dune types and systems provides invaluable information to improve reservoir performance through capturing the geologic controls on production in static models. This will lead to improved recovery of existing aeolian targets through more geologically realistic reservoir models and improved production history matches.

To investigate this hypothesis, core, FMI and wireline data from a deeply buried aeolian gas field from a Rotliegend gas field onshore Germany with 30+ years of production is combined with multiple outcrop analogues in Utah, USA to build a predictive reservoir model and flow simulations for improved recovery. This includes the analysis of fault and deformation band distribution within the reservoir as well as of the dimensions and reservoir quality of dune bodies. This study will help understand the architecture of smaller, structurally and sedimentologically complex dune systems and will be applicable to similar aeolian gas reservoirs.

NOTES:

Poster Abstracts

Capturing Large Scale Conceptual Geology in the Enyenra Field

Douglas Obeng, James Cheeseman, Ingrid Demaerschalk, Bryan Cronin, Damian Kelly
Tullow Ghana Limited

The 'one model fits all' approach to modelling often disappoints. As software is pushed to its limits, with grid cell counts maximised to include as much detail as possible, run times of the associated flow simulators are often slowed. This approach can be inefficient and normally take longer than necessary. In some oil and gas fields, especially ones with significant geological complexity, a better approach might be to abandon the assumption that all fields necessarily require full field detailed models and to open up options of other workflows, notably multi-model, multi-scale approaches. In such instances, the multi-model approach, if appropriately designed, tends to be both quicker and more effective than the 'single big model' approach.

The Enyenra Field is an Upper Cretaceous levee-confined slope channel complex with pronounced axis, margin and levee facies belts. The Field is a 30km+ long feature with a line production development strategy targeting the axial facies belt using smart well technology. The internal heterogeneity of the facies belts requires fine detail to capture locally. This makes it a candidate for the multi-model approach in order to capture adequately and effectively the different scales of geology.

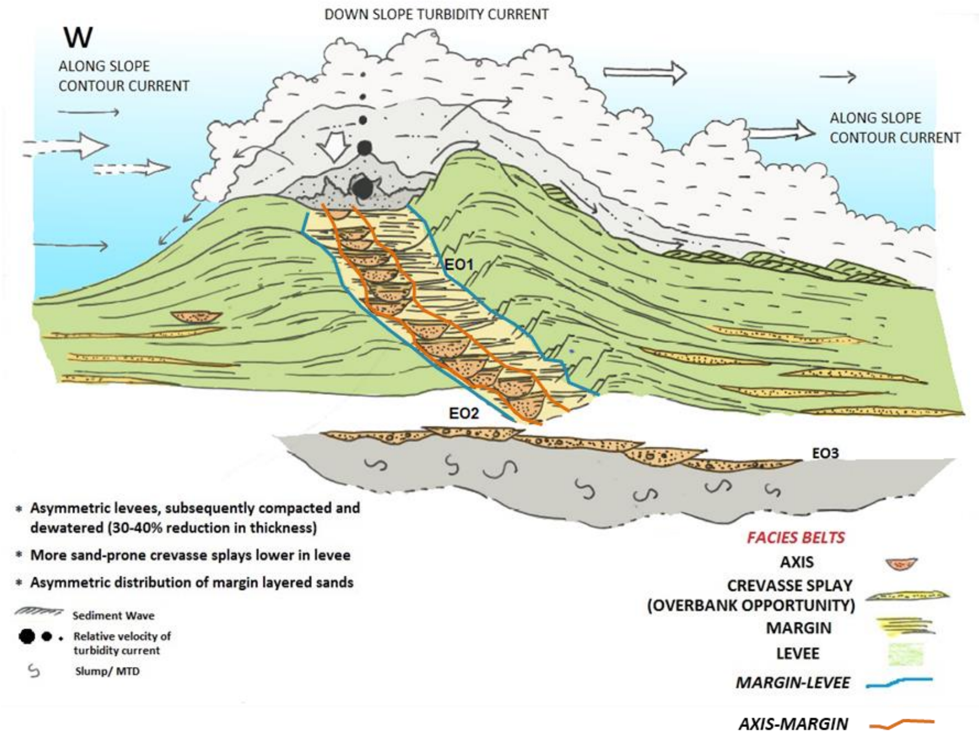


Figure 1 Geological conceptual model of the Enyenra slope channel complex

Two models, resource model and decision model, have thus been built. Both models are built using the same input data including seismically mapped polygons that demarcate the facies belts as model regions.

The resource model has been built full-field and covers the entire Development and Production Area (DPA) to evaluate the in-place resource range as well as serve as an 'evergreen' database which can be updated as new data becomes available. It has no permeability or flow detail and is not intended for simulation. Each facies belt region is modelled independently using the relevant geological concept. The result is a volumetric range covering different scenarios for each facies belt. The Resource Model has also given the flexibility to choose/combine different scenarios in the form of a matrix to define various resource/reserve cases.

The decision model, covering only the axial belt region, is built as sector models (static/dynamic well pairs) at the production unit scale to capture the flow behaviour of the field. These have been used to generate low/high profiles, frozen in time at suitable planning/decision points, rather than being continually updated. The result is a leaner model incorporating all the essential fine detail to yield better history match, increasing our confidence in forecasts.

Both models were delivered more efficiently and within a shorter timeframe.

Risking across-fault juxtaposition using an empirically calibrated fault zone model

Tom Manzocchi[1,2], Conrad Childs[1,2], Andy Heath[3], Isabelle Telles[1,4], Marcus Carneiro[2,1],
[1] *University College Dublin, Ireland*
[2] *Irish Centre for Research in Applied Geosciences (iCRAG), University College Dublin, Ireland*
[3] *Independent Consultant*
[4] *Baker Hughes, Delft, Netherlands*

The initiation of normal faults as arrays of subparallel fault segments, followed by the progressive localisation of fault displacement across breached relay zones as the fault grows, is a well understood process resulting in geometrically complex fault zones. Over recent years we have examined many hundreds of normal fault zones from a diverse range of geological systems using outcrop observations and high-resolution seismic mapping to establish a quantitative description of normal fault zones, calibrated to different geological settings. In this description individual fault zones are characterised by three constants relating to the frequency, aspect ratio, and degree of breaching of relay zones upon the fault traces. We have concluded from this work that, as a general rule, seismically irresolvable fault zone structure is capable of significantly influencing across-fault juxtaposition of reservoir-scale faults (e.g. fault with throws in excess of ca. 50m). In parallel to this quantitative structural geology, we have developed algorithms and associated software for modelling stochastic sub-seismic fault segmentation for reservoir faults constrained by these constants, with application in both exploration and development workflows. This presentation will provide an overview of both the geological data and conceptual understanding underlying our quantitative model of fault zone structure, and of the technology developed to apply the model to practical reservoir-related questions.

An example application of this work inspired by the flier to this conference is shown in Figure 1. The faulted horizon contains a number of seismically imaged and explicitly mapped breached relay zones (labelled A, B, C in Figure 1a). We have found that most reliable quantitative description of seismically irresolvable relays should be obtained from the characteristics of the seismically visible ones. Therefore, a geometrical and kinematic analysis of the visible structures such as these should provide the input to any subsequent modelling of the effects of sub-seismic structures. The frequency of relay zones in inversely proportional to their size, and therefore the frequency of irresolvable relays in a particular fault system can be estimated from the frequency of larger, visible ones. Similarly, the strain a relay ramp can support before breaching is more or less constant for different sized relays in the same fault system (but different for a fault system formed under different geological conditions), and therefore the seismically resolved relays can be used to deduce the likely geometry of seismically invisible ones. This is manifest in the mapped horizon by the wider ramp (A) being associated with a greater ramp dip (and hence a later breaching) than the narrower ramps on a similar sized faults (ramps B, C).

The analysis in Fig 1 focuses on the fault in the foreground (Labelled x-x' in Fig 1a) and addresses the question of the likely depth of a spill-point across this fault out of the hangingwall compartment. The scale and vertical exaggeration of the model are not provided in the image, and in the analysis presented in Fig 1, we have assumed that the contour interval is 10m and that the horizontal distance from X to X' is 4km. This implies a maximum fault throw of about 150m, and the analysis considers a 30m thick reservoir unit. The deterministic spill point therefore occurs at the point where the fault throw exceeds 30m (Fig 3a). The footwall and throw profiles of the fault have been approximated from the image and loaded into FaultMaker (Fig 1b). These, and the quantitative description of the relay characteristics (we have used a representative description from our database in this example), provide the basis for the stochastic FaultMaker modelling (Fig 1c). In the analysis presented, 100 realisations of possible sub-seismic fault zone structure have been constructed and analysed for spill-point depth (Fig 1c, d). The P10 and P50 cases are within 100m of the deterministic case, but the results indicate the presence of a long tail up to the P90 case with much shallower spill-point (Fig 1d). This is because the fault throw increases up-dip, and therefore a shallow spill-point relies on a large but rare relay as more common smaller ones will be breached earlier and therefore will not provide across-fault juxtaposition at larger throws.

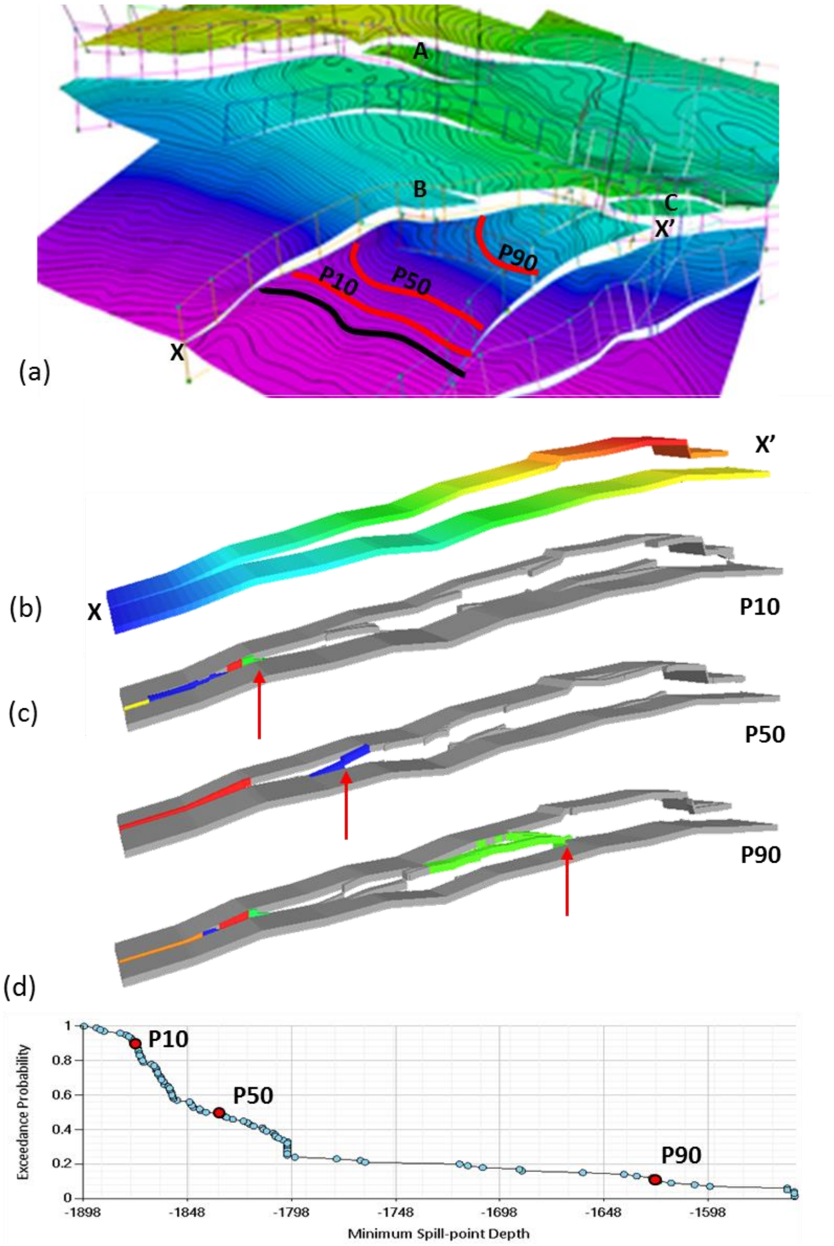


Figure 1. (a) Reproduction of the image from the conference flier, with the analysed fault (X-X') and three breached relays (A, B, C) indicated. The deterministic (Black) and P10, P50 and P90 spill-point depths resulting from the analysis are drawn in the hangingwall compartment of the fault of interest. (b) Fault X-X' loaded into FaultMaker. (c) Three FaultMaker realisations showing subs-seismic fault zone structure. Coloured areas represent flow paths across the fault, and the red arrow highlights the spill-point associated with the shallowest of these, for each realisation. (d). The risking curve for 100 realisations of this fault zone. The red circles indicate the three realisations shown in (c).

Assessing and communicating risk in early stage exploration: embedding regional understanding within basin modelling workflows

Natasha Dowey[1] and Christine Yallup[1]
[1]*Halliburton Landmark*

During the early stages of exploration, uncertainties regarding the nature and presence of a petroleum system are significant. The accuracy of exploration predictions is largely dependent on datasets available and the ability of subsurface models to characterize real-world conditions. Multiple scenarios for interpretation must be predicted, tested, and evaluated when conducting exploration in frontier areas; and, at this stage, only a limited number of factors can be equivocally resolved, making risk assessment challenging.

Basin modelling during the early stages of exploration allows for vital investigation of charge risk, a common cause of exploration failure. However, in new frontiers, there is typically little data available to constrain crucial thermal conditions, such as heat flow and geothermal gradient. Regional geological and tectonic context therefore provides a fundamental and primary framework for developing predictions and understanding uncertainty in models. This study presents an integrated workflow for basin modelling in a regional context, using case studies from global frontier rifted margins. The work demonstrates that meaningful, quantitative predictions can be made, even during the early stages of exploration.

Firstly, the work presents how regional context can be implemented to construct and condition subsurface models in frontier kitchen zones. Geological and tectonic framework is used to identify analogues, the adoption and calibration of which can narrow uncertainty in model inputs and inform boundary conditions. Depositional models are applied to help minimize stratigraphic uncertainty, and tectonic and climatic models are used to develop thermal scenarios. Examples from Southeast Asia, South America, and Central America are used to highlight how simple extrapolation of conditions is often inappropriate.

Multiple predicted scenarios are then tested using sensitivity analysis, which quantifies the plausible range of outcomes for a study area, de-risking some inputs and highlighting critical factors for further study. An example from a tectonically complex area of offshore Ireland is presented to illustrate this iterative process. Scenarios are constantly adapted as testing progresses to better hone the subsurface model and help improve predictions. Outcomes and risks are evaluated and uncertainties involved during each stage are clearly communicated.

The results of the case studies presented demonstrate that modelling and sensitivity analysis used together with regional understanding are powerful tools for addressing uncertainty during early stage exploration. This work illustrates that iteration of multiple scenarios helps provide a fuller picture of potential risk than a simple extrapolation of play concepts from proven successes, particularly in tectonically complex areas.

Keywords: modelling, early stage exploration, regional context, risk, uncertainty

Improving reservoir facies modelling with analogue databases.

Simon Lomas, Dan Hemingway, Mark Verschuren, Matthew Bowyer, Laura Roberts.
Petrotechnical Data Systems Ltd

Using analogue data to build or validate facies models is considered best practice in reservoir modelling. However, the practical reality of analogue usage is challenging: what type of data should be used? are sufficient data available? do the available data cover the range of depositional elements encountered? are the data in a usable format for reservoir modelling?

We present an efficient methodology to condition facies models directly with high-quality sedimentary analogue data. Quantitative analogue data distributions are used to inform both object-based and variogram-based modelling algorithms. By incorporating appropriate analogue information, an improved and defendable distribution of reservoir facies through the model can be achieved. Furthermore, effective investigation of depositional uncertainties is enabled by the selection of suitable analogue sets to define a range of contrasting but geologically realistic scenario models.

This presentation illustrates the value of analogue-informed reservoir models using data from two case studies. The case studies come from offshore NW Australia and onshore New Zealand and demonstrate the improvement of facies models in fluvial and shallow marine successions achieved through focused use of an extensive analogue database. The database-guided results are contrasted with ones based on a literature review and the default parameters set in the reservoir modelling software. The use of high-quality analogue data gives enhanced confidence in the resulting facies models and the distribution of facies in the interwell space, while also allowing alternative plausible scenarios to be considered.

The impact of structural and water saturation uncertainties on reservoir models.

Mark Verschuren, Matthew Bowyer, Dan Hemingway, Simon Lomas, Laura Roberts.
Petrotechnical Data Systems Ltd

Three-dimensional geological models are routinely used to simulate reservoir properties and conditions. The models are used to forecast field production and as a basis for assessing economic viability. However, our inability to image and understand the subsurface accurately introduces a range of uncertainties with significant impact on our reservoir models. Two areas prone to uncertainties are the structural framework and distributing saturations throughout the reservoir model.

Structural uncertainty can be viewed in terms of fault and horizon position, and fault connectivity. The former impacts gross rock volume (GRV) and ultimately the volume of in-place hydrocarbons, while the latter affects the connectivity of the reservoir, development plan and well count. Uncertainty in GRV is often analysed in Monte Carlo simulations, but the way in which fault connectivity impacts reservoir performance, well count, and development plans is often poorly understood because reservoir models are commonly anchored on a single framework scenario.

Modelling multiple scenarios of fault connectivity could impact whether the free-water level varies by fault block or perhaps there is uncertainty in the method by which saturations are modelled. The application of a saturation height function to a reservoir model with multiple fault blocks can be a time consuming, arduous process manifesting itself in a single calculation method being considered without regard for other plausible methods.

This presentation will investigate the effect fault connectivity has on reservoirs by way of the number of faults blocks or their area and the likely well count required in each of the scenarios. The uncertainties in the structure and the saturation models are viewed through multiple grids each with differing views on fault interaction and through varying the saturation calculation methodology. By quickly generating multiple structural grids and easily applying a range of saturation height functions to those grids, the uncertainty space around development plans and well count is explored.

Quantitative Analysis of 3D Sub Surface Modelling Updates While Drilling

Simon Austin,
Baker Hughes a GE company

Reservoir navigation of wells is a highly skilled, valued, and integrated part of the drilling process, especially in complex, deviated development wells steered through challenging geological targets. Real-time modelling is a new, significant extension in capability to reservoir navigation.

This presentation demonstrates a step change in traditional Reservoir Navigation techniques based on a curtain section of the well to a quantitative 3D sub surface modelling approach using real time LWD data transmitted with WITSML.

The focus of the new approach is fast, localized analysis (measured in minutes) with a quality high enough to enhance operational decision making.

New, Integrated Geology-to-Geomechanics Workflows Offer Production Risk Mitigation without Compromising Reservoir Complexity

Camille Cosson
Emerson Automation Solutions

Theme: Embracing New Modeling Technology and Approaches
Sustainable field management cannot be performed without a thorough knowledge of reservoir mechanics and how they change throughout the life of the field. These changes can affect infrastructure, well stability, life expectancy, reservoir productivity, and consequently investment and revenues.

The ability to reliably assess geomechanical risk throughout the reservoir's lifetime, in order to plan field development and production with confidence, is still perceived as a challenge for the Oil and Gas industry.

Although 1D models are widely used, most of the geomechanics studies are in fact well-scale studies. These are not enough, as experts also need to understand how rocks and stresses are distributed in the 3D space of the reservoir and surrounding areas in order to plan efficient field development and production. Extrapolation between wells is far from sufficient for assessing reservoir mechanics away from the wells, as the assumptions required to apply these models generally lead to an oversimplification of 3D stress distribution in the subsurface. The resulting outcome does not always reflect the complexity of the underlying geology.

Due to their cost, complexity and length, 3D geomechanical studies are not systematically undertaken. It is when unpredicted reservoir behavior leads to unexpected costs that we realize the importance of such analyses.

Finite Element Methods (FEM) are particularly appropriate for accurately portraying stress distribution in the subsurface, but the requirements needed to conform to structural and stratigraphic features make these models daunting. Moreover, current commercial software does not accurately model the reservoir's geomechanical response to field production because it uses traditional modeling methods designed for Finite Difference-based flow simulations. These are not always suitable for propagating geological complexity to geomechanics, and may oblige to do unwarranted simplifications of the 3D mechanical earth model. Over-simplification can cause serious issues in some cases, for example, with fault re-activation.

This paper proposes a workflow for efficiently generating mechanical models that better capture geological and mechanical complexities, while reducing the time spent creating them from months to days.

Through the integration of all information from different sources into a common framework, we show that it is possible to reconcile all geoscience disciplines (geophysics, geology, reservoir engineering, geomechanics, etc.), around one shared structural model - the SKUA model, which is created honoring all available data with no unwarranted simplifications.

Because the approach we present is fully automated, it also enhances the seamless propagation of information across domains, so that all models are consistent with one another and integrate all the key information. This supports the generation of fit-for-purpose numerical representations of the subsurface.

In this presentation, we will also demonstrate how the use of advanced 3D structured and unstructured gridding technology enables the generation of optimal Finite Element Meshes that fully capture current and future reservoir geomechanical behavior (Figure 1).

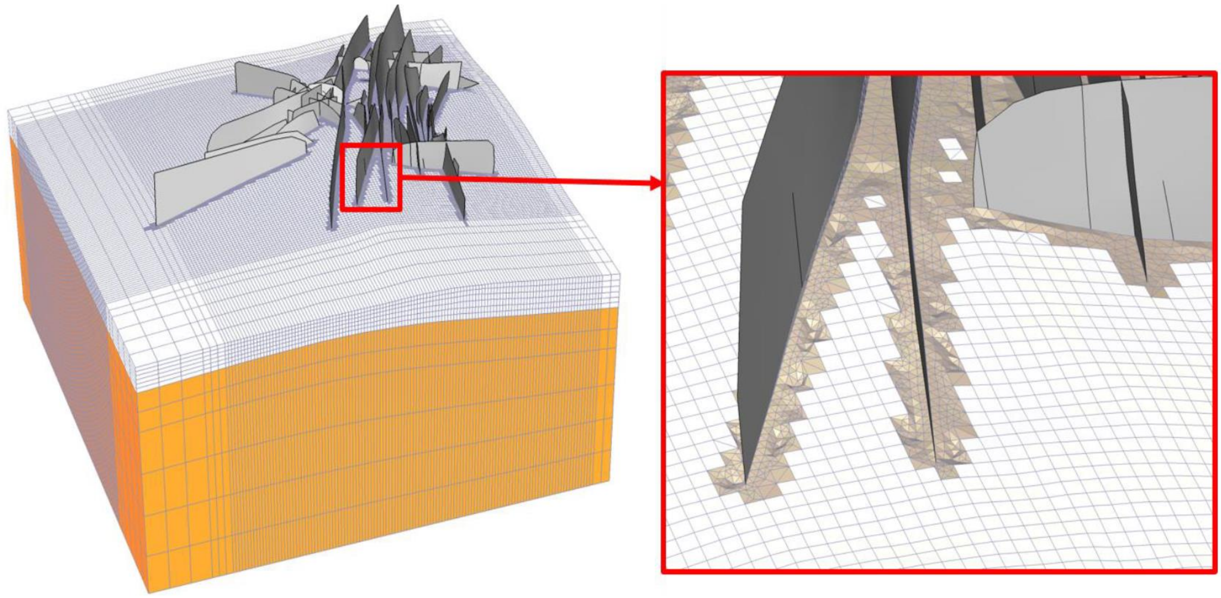


Figure 1: *The Hybrid grid is optimized for Finite Element Simulations: tetrahedral cells are generated along geometric complexities such as faults (zoom). Away, hexahedral cells conformable with stratigraphy are grown and fill the gaps.*

We will show how combining advanced automated 3D meshing methods with true integration across domains and disciplines reconciles geology and geomechanics, to produce reliable 3D/4D geomechanical models that preserve key complexities.

Leveraging 4D Seismic into the Static Model: a Simple Approach in a Deep Water Lobe Reservoir, Paladio Field, Block 18, Offshore Angola

Neila da Costa Mendes ,
Reservoir Development, BP Angola

The Paladio Field is located in Block 18, offshore Angola, West Africa. The field is a relatively tight anticlinal 4-way dip closed structure that has evolved in response to salt movement and extension throughout Miocene and Oligocene times. In terms of stratigraphy the field contains three stacked turbidite reservoirs-the o72 and o73c lobes and the o73de channel complex. The main technical drivers for a new model build at Paladio was to develop a model with sufficient detail to incorporate the 4D anomalies observed in the first 3 seismic monitor surveys (2009, 2011 and 2013) post startup of production in 2008. The 4D response represents fluid movement highlighting vertical and lateral heterogeneity at the well and field scale, with the objective to provide a tool for reservoir management to enable more reliable production forecasts and informed decision making in real time.

Simulation of Turbidites with Forward Stratigraphic Modeling

Sergio Courtade[1], Henrique Picorelli Ladeira Dutra[1], Mostfa Lejri[1], Abhishek Moharana[1], Dan Tetzlaff
[1]*Schlumberger*
[2]*Consultant*

Forward stratigraphic modeling involves a major paradigm shift in the geologic modeling domain, while geostatistical models are controlled by geometrical parameters FSM is driven by a mathematical representation of the physical laws controlling erosion, transport, and deposition of clastic sediments, as well as carbonate growth and redistribution.

Turbidites are transported by gravity flows below the wave action depth, the facies distribution is mainly controlled by the input of sediments, topography and synsedimentary tectonics, these controls evolve through time and they are more difficult to incorporate into static 3D models than in dynamic 4D forward stratigraphic models. Here we present some of the challenges and findings of simulating turbidite deposits with forward stratigraphic modeling in GPM (Geologic Process Modeler) the software package used for this study.

Source to sink deterministic numerical models fall under three main categories depending on the sediment transport calculation approach used (Hawi et al. 2019), the fluid-flow model used in this study (GPM) is based on hydrodynamics using an approximation of the Navier–Stokes equations (Tetzlaff andHarbaugh,1989) and it provides an accurate representation of the physical processes allowing to achieve realistic sedimentary patterns. The acceleration for the pulses of turbidite flows is simulated based on the particle in cell approach.

The simulation process starts with the definition of an initial topography that describes the geometry of the basin at the time of the start of deposition of the unit to be modeled. Then a sediment source area is defined, (sediments and water for the turbidite flows will enter the model in this area) in addition to the input rate for water and sediments and the flow-pulse frequency. Another important input is the synsedimentary tectonic movement history for the different structural elements (platform, slope, basin, minibasins) in the model.

The simulation reproduces the physical process of turbidite flows initiation and downslope movement, the erosion of the platform and formation of canyons and the channel fills and lobes deposition as the flow slows down. The defined input parameters control the details of these processes and therefore the location, architecture and extension of the different architectural elements and corresponding facies distribution and stacking pattern of the turbidite depositional system.

A major challenge for this technology is the conditioning of the model parameters to honor the well and seismic hard data, this process can be done manually or automatically using uncertainty and optimization engines. In our examples the most important elements of this conditioning process were the initial topography, the synsedimentary tectonics and the history of water and sediments input into the basin.

The examples we have built cover slope and basin floor turbidites and they reproduced all the processes and architectural elements observed in outcrops and integrated into conceptual sedimentary models, some of them are: Channel erosion and filling, decreasing grain size in a single flow (Bouma sequence), levees on channels edges, downslope transition of channels to lobes, channel crevassing and lateral compensation, bypassing of minibasins, prograding and abandonment stacking patterns (Figure 1).

The observations resulting from these models demonstrate that FSM accurately reproduces the sedimentary architectures and facies distributions observed at outcrops and field studies and documented in conceptual models; in addition , the predictions obtained from these models are in well agreement with the information obtained from other sources (3D seismic, drilling) supporting the value of this technology for predicting facies and petrophysical properties in exploration and field development activities.

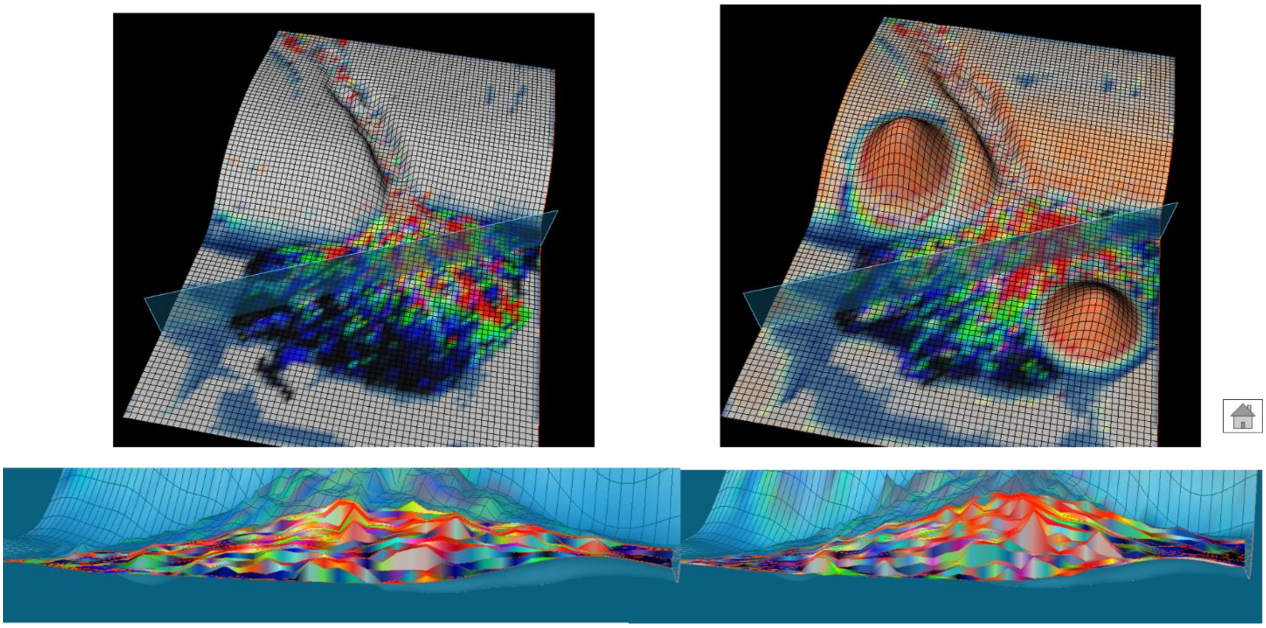


Figure 1: Conceptual turbidite example showing the concentration of sandstones due to the confinement caused by a synsedimentary dome

Applying Geological Process Simulation Outputs to Constrain Lithofacies Modeling in a Basinal Fan Geological Setting: An Example.

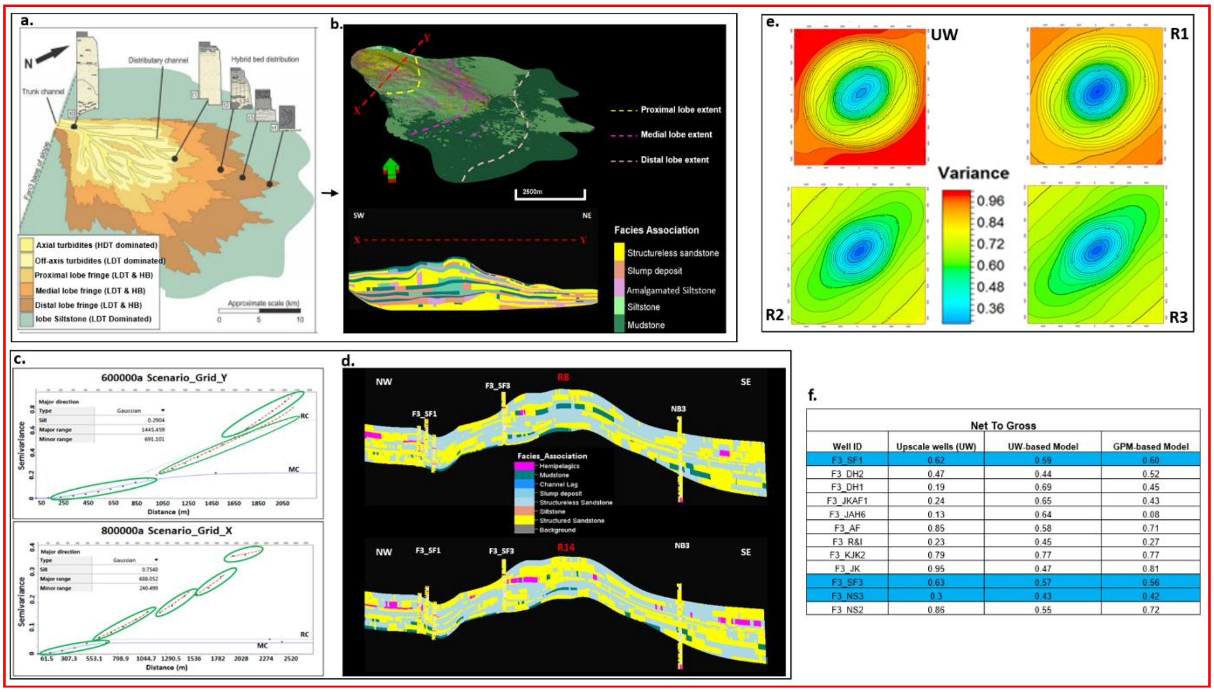
Daniel Otoo & David Hodgetts
University of Manchester

Abstract
The focus of this work is to model lithofacies distribution in a basinal fan complex by applying a variogram based modeling method that relies on sediment distribution and statistics derived from geological process simulations. Lithofacies distribution in hydrocarbon reservoirs serve as a key control on fluid mobility, hence accurate characterization of facies heterogeneity in a geological model is critical for an enhanced fluid behaviour prediction and implementation of efficient recovery strategies. The methodology applied involves two steps: (i) a geological process modeling (GPM) software is applied to simulate the build-up and distribution of sediments in a turbidite fan/lobe complex (ii) applying geostatistical parameters and sediment patterns derived from GPM to constrain lithofacies modeling in a variogram based method.

Available data includes; well logs/ outcrop logs from the Skoorsteenberg formation, fault and stratigraphic interpretations from previous study (Hodgetts et al. 2004). Tanqua Karoo fan 3 unit is a sand-rich submarine complex that is stratigraphically separated by siltstone and hemipelagic clay units. Thirty stratigraphic models of the fan complex were generated and analysed. Results show a significant improvement in lithofacies characterization; evident in Net to Gross estimates in GPM-based facies models relative to standard variogram based modeling from well logs, leading to the conclusion that a robust geological process model will provide an important stratigraphic framework for 3-D facies modeling.

Introduction
Facies distribution in hydrocarbon reservoirs is a direct function of the complex integration of physical, chemical and biological processes (Pyrcz et al. 2015). Considering the effect of lithofacies patterns on petrophysical property distribution as well as fluid behaviour in reservoirs, geological modeling techniques that aim at generating geologically realistic 3-D models have been applied in various studies (e.g. Hu & Chugunova, 2008; Huang et al. 2015; Sisinmi et al. 2017). The focus of this work is to reproduce a depositional model in a thrust faulted sedimentary basin, and use its output to evaluate the capacity of resultant GPM-based lithofacies models to honor available facies logs. The methodology presented here applies sediment distribution trends and geostatistical parameters from the geological process modeling to constrain facies property modeling in Schlumberger's PetrelTM software. The GPM-based approach seeks to leverage the best of each approach; the forward stratigraphic modeling technique (e.g. Pyrcz et al. 2015) for geological/stratigraphic realism and variogram based method (e.g. Ringrose and Bentley, 2015) for data conditioning.

Results
Key attributes and associated sediment patterns in fan/lobe complexes; i.e. proximal lobe, medial lobe, distal lobe, axial and off-axis turbidite bodies typical in turbidite fan complexes (e.g. Prelat and Hodgson, 2013) are reproduced in GPM. Geostatistical outputs from GPM provide a better representation of facies bodies in 3-D, contrary to "well log-based" variograms that are limited in correlating facies heterogeneity in lateral directions. GPM-based modeling produced comparable correlation coefficients and Net-to-Gross to available facies logs than is the case for standard variogram based modeling. Figure 1 shows some results from this work.



Net To Gross			
Well ID	Upscale wells (UW)	UW-based Model	GPM-based Model
F3_SF1	0.62	0.59	0.60
F3_DH2	0.47	0.44	0.52
F3_DH1	0.19	0.69	0.45
F3_JKAF1	0.24	0.65	0.43
F3_JAH6	0.13	0.64	0.08
F3_AF	0.85	0.58	0.71
F3_R&I	0.23	0.45	0.27
F3_KJK2	0.79	0.77	0.77
F3_JK	0.95	0.47	0.81
F3_SF3	0.63	0.57	0.56
F3_NS3	0.3	0.43	0.42
F3_NS2	0.86	0.55	0.72

Figure 2 a. schematic perspective of turbidite Fan 3, Skoorsteenberg formation (Kane et al. 2017) b. geological process model scenario of turbidite Fan 3 complex c. variogram model of a GPM scenario d. cross-sectional view of two GPM-based facies model realizations e. variance maps; UW is upscaled well logs and R1-R3 model realizations f. Net-to-Gross estimates; blue coloured and plain rows show wells included in facies modeling and pseudo wells from GPM-based facies models respectively.

Conclusions

This work illustrates how geostatistical parameters and sediment distribution patterns from geological process simulations can be applied to constrain facies modeling in a variogram based algorithm. With careful calibration of GPM parameters, realistic geological attributes that are characteristic in turbidite fan/lobe complexes are reproduced. Also, an improved distribution of lithofacies bodies within inter-well volumes is achieved; noticeable in the comparative analysis of pseudo wells derived from GPM-based models to available facies logs. These initial results shows that a robust geological process model can provide an essential framework for characterizing facies heterogeneity in 3-D geological models.

Reproducing net:gross and amalgamation ratios in rule-based models of deep-water lobe systems

Javier Lopez-Cabrera[1,2], **Tom Manzocchi** [1,2], Peter D.W. Haughton [1,3]
[1]Irish Centre for Research in Applied Geosciences, University College Dublin, Ireland
[2]Fault Analysis Group, School of Earth Sciences, University College Dublin, Ireland
[3]Marine and Petroleum Geology Group, School of Earth Sciences, University College Dublin, Ireland

Conventional cell-based modelling techniques excel at reproducing spatial statistics, while process-based methods are proficient at producing geological realism. As a novel halfway approach between them, rule based methods are an excellent alternative for reproducing geological realism but maintaining a low computational cost. This is because rule based modelling considers models as 2D spatio-temporal surfaces sequentially stacked, mimicking geological processes but without simulating the physical flow-deposit interactions. Each 2D surface - or event - will be influenced by the previous events, while at the same time it will constrain the following deposits. This is a particularly efficient approach for modelling deep-water lobe systems. Deep-water lobes contain geological features which are very hard to model by other methods, such as thin but laterally extensive interconnected networks of shale baffles arranged hierarchically, compensational stacking and erosion. Depositional geological processes result in heterogeneities that have significant influence on fluid flow paths and recovery factors in deep-water lobe reservoirs, and therefore properly modelling them is critical in order to make better informed reservoir management decisions.

In this work, a rule based modelling code for modelling deep-water lobes has been defined. The code includes a four-fold hierarchy of element and inter-element deposition and erosion. The hierarchy is controlled by defining nested areal constrains while erosion is controlled by an event probability. As typically observed in deep-water lobes, hierarchical compensational stacking organisation is dominated by avulsion. This is achieved in the code by defining a critical slope for each hierarchical object. Smaller hierarchical elements will aggrade until the critical slope is attained, triggering an avulsion and the formation of a new component. For example, beds will commonly aggrade until a threshold is reached, leading to avulsion and the formation of a new compensational set of beds. In this sense, these models are novel in terms of erosion between elements and hierarchical organisation by the addition of inter-element shales and autogenic avulsion. The modelling rules mix different processes (erosion, stacking patterns) that mimic geological ones, and the resultant models are similar both qualitatively and quantitatively to real-world observations.

Models successfully reproduce complex geometrical frameworks as a result of hierarchical compensational stacking (figure 1). Because of the geological realism of these rule based models, they can complement studies of outcrop analogues for constraining the types of stacking patterns that should be included in more conventional reservoir geomodelling. Properties related to lobe environments that will have an impact on reservoir properties such as net:gross ratio (NTG) and amalgamation ratio (AR) can be extracted from the models. A decrease in net:gross ratio values from proximal to distal lobe environments should be expected (figure 1a, cross section y-y'), as well as large AR values close to the source.

Amalgamation ratio values often show values significantly lower than net:gross ratio values in natural systems, yet conventional models struggle to reproduce this behaviour. The relationship between NTG and AR can be associated to the compression factor (cf), and different deep-water systems appear to be characterised by different cf curves (figure 2a). The new rule modelling code reproduces the relationship between NTG and AR efficiently, showing their characteristic curve where AR is lower than NTG. Like natural systems, we find that models generated with different input conditions (i.e. different propensities for erosion, deposition, avulsion and aggradation at different hierarchical levels and degree of confinement) have different compression factors (Figure 2b). Models with different NTG and AR can be adjusted systematically to calibrate models to data extracted from outcrops, following the cf trends which can be inferred from them. This can have important implications for understanding irresolvable reservoir properties (e.g. amalgamation ratios) as a function of larger-scale sedimentological features. This relationship also could help to serve as a criterion for identifying and modelling proximal, medium and distal lobe environments, which will have different reservoir properties since lobe environments are partially defined by NTG and AR.

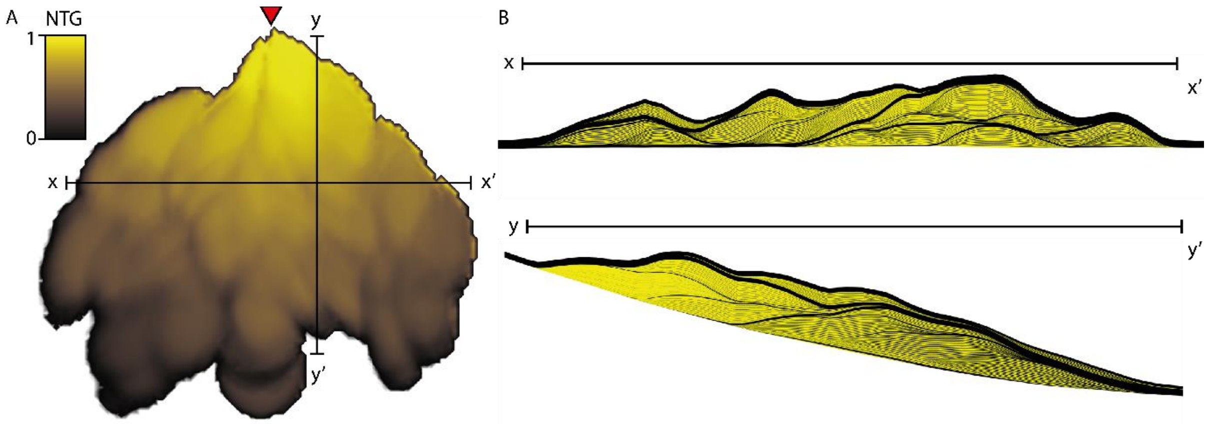


Figure 1. A) Map view of NTG of a modelled hierarchical lobe consisting of >550 events, compensationally stacked and deposited on a slope of 0.2°. Horizontal dimensions are 30x30km. The red triangle defines the source point. B) x-x' and y-y' cross sections, drawn with a vertical exaggeration of 50. Note how there is a gradual NTG decrease downdip.

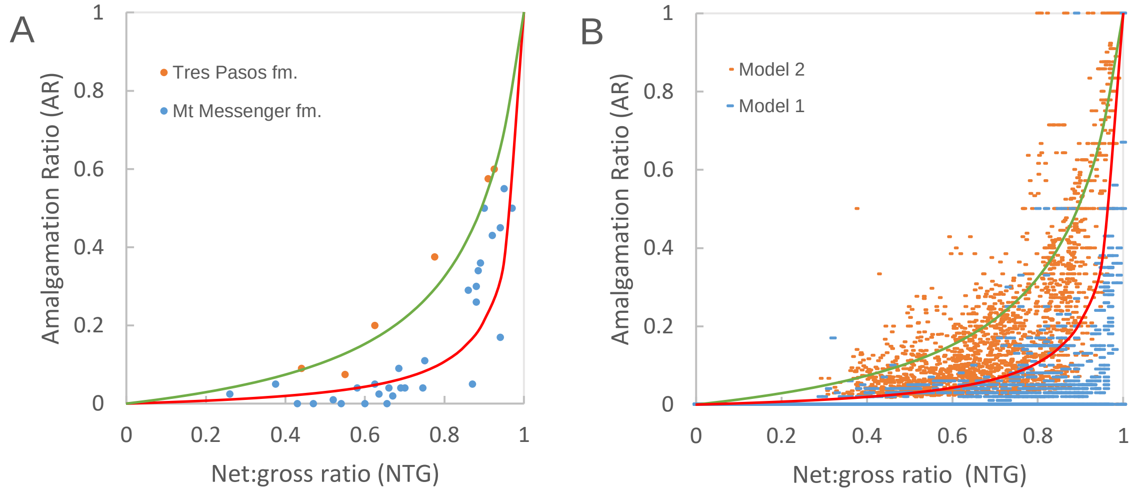


Figure 2. A) Net:gross ratio (NTG) vs amalgamation ratio (AR) for two systems described in the literature. Lines represent the trends for Mt. Messenger fm. and Tres Pasos fm. (cf = 0.03, 0.12 respectively). B) NTG vs AR for two models with the same input but different erosion probabilities, similar to the ones shown in 2A. Trends represent the same cf values as in 2A.

This publication has emanated from research supported in part by a research grant from Science Foundation Ireland (SFI) under Grant Number 13/RC/2092 and is co-funded under the European Regional Development Fund and by PIPCO RSG and its member companies. Schlumberger are thanked for an academic Petrel license.

Bridging the Gap between Rocks and Recoverables in Tight Gas

Behrooz Bashokooh, Chris den Boer, Alberto Mendoza, Peter Whorton
Shell

The Greater Sole Pit (GSP) includes several tight gas fields in offshore block 48 of UK Southern North Sea, which have been developed with different development concepts from 1965 to 2014; from deviated to horizontal drilling, dual laterals and finally underbalance drilling. Despite these progressing stages of development, the recovery factors are still relatively low (30-50%) which is explained by the fact that large parts of the reservoirs are tight. Especially the highly heterogeneous upper “A-sand” reservoir interval will have vast amounts of gas remain in place at the end of field life, in case of no further development. Furthermore, the decline of production from the current wells (mainly situated in the better-quality sands) is having a negative impact on the profitability of the asset, as the operating costs remain nearly constant. To unlock production from the tight sands, the technology of multi-stage fracking in horizontal wells is the key enabler, but for a long time the costs were too high and the recovery expectations in tight sands remained uncertain.

Assessing and reducing the uncertainty of the expected recovery demands a special focus on identification and capturing the complexities that matter for further development of the tight reservoir blocks. These Permian-aged aeolian dominated reservoirs demonstrate multi-scale heterogeneities from field wide variation in proportion of of lithofacies assembledges to differences in diagentic foorprints at the scale of pore throats. These heterogeneities are the reflection of a complex depositional and diagenetic history.

Integrated data analysis and iterative examination of data-driven concepts, established a link between primary lithotypes and their reservoir properties, enabled by the characterization of a relationship between a scaled volume of clay index, porosity and permeability (Fig 1). Coupled with permeability-based saturation height functions, this approach enabled us to follow through with a mult-scenario apparoach to explore a wide range of alternative scenarios of top structure, free water level, lithofacies proportion, porosity, permeability, saturation, Kv/Kh and relative permeability. Well design and hydraulic stimulation concepts were tested iteratively against those scenarios, linking the reservoir characterization narratives to the development choices and decisions.

The established link between rock type, porosity, volume of clay, permeability and saturation estimation enabled a creative new way of result evaluation for each of the scenarios by the method of effective permeability classification of the gas Initially In place. In addition to the estimate of the total gas in place in each subsurface scenario (Fig 1, bottom-left), we could create volumetric result breakdowns of the total in place volume per effective gas permeability (Keff) class.

A select group of subsurface scenarios were initially tested against alternative well design and completion concepts. Fig 2 (Top Left) shows the comparison between In place gas volume of those scenarios with the expected UR of the proposed well. Typical to the situation in tight gas, there is a wide uncertainty range for the relationship between the Initial gas in place and the expected ultimate recovery. Using the Keff volume reporting however, showed that if we look at the in place volume that is held by rocks with Keff > 0.1 mD or higher and compare them with the expected UR outcome from dynamic simulation, a very strong correlation could be discerned . It was thus possible to directly translate the distribution of the In place volume scenarios to the equivalent of recoverable volumes using Keff classification as a proxy. (Fig2- Bottom-Right).

Conclusion

This case study emphasizes the critical role of integrated data analysis prior and during integrated reservoir modelling. It provides a working example for the effectiveness of Decision-Based Integrated reservoir Modelling (DB-IRM) mindset. By breaking up the complex attributes of tight gas reservoir into characterizable elements, we kept the scope of IRM workflow in check, preventing over complication while constantly aligning model assumptions and outcomes with the requirements of the development decisions.

Characterization of effective gas permeability is the bridge that links rocks to recoverables and enables robust evaluation of development decisions in tight gas. Keff classification and it's use as UR proxy was a significantly reduced dynamic simulation runtime and created a reliable sense-check for decision makers and join venture partners, significantly enhancig decision quality for the project.

Acknowledgements: We wish to extend our thanks to members of the Greater Sole Pit development and WRFM technical teams and their leaderships over the years. Special thanks to PETGAS joint industry project on for the essential new insights on tight gas petrophysics and adjustment of releative permeability measurements.

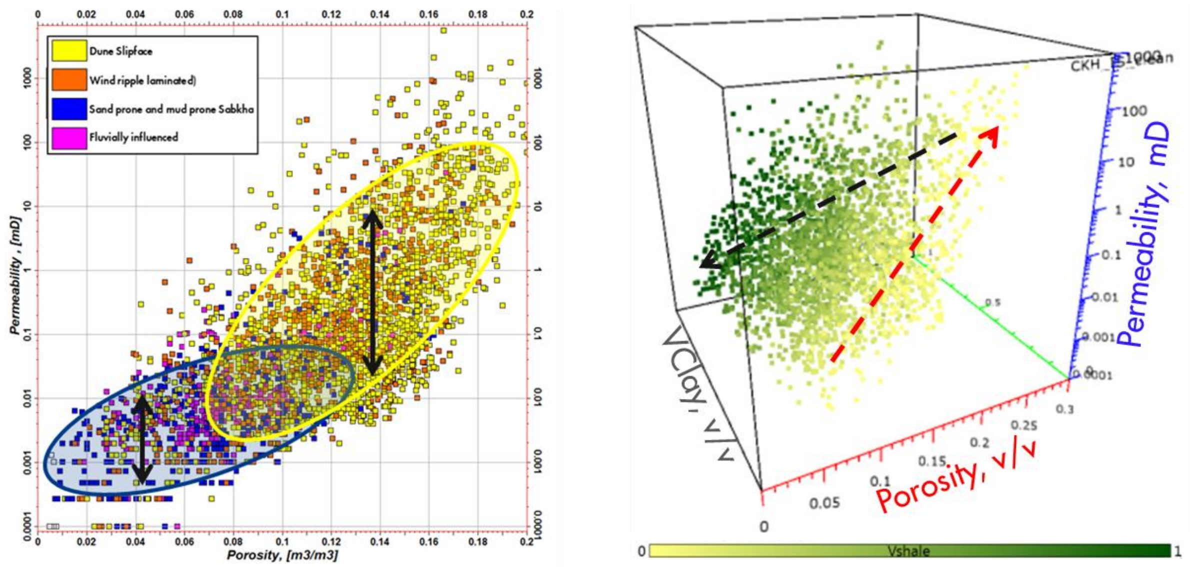


Fig 1: (Left): Core plug Por-Perm cross plot differentiated by lithofacies. (Right): Proportion of Clay matrix (value 1 means ~16% clay in the matrix) further differentiates the permeability of sands with similar porosity.

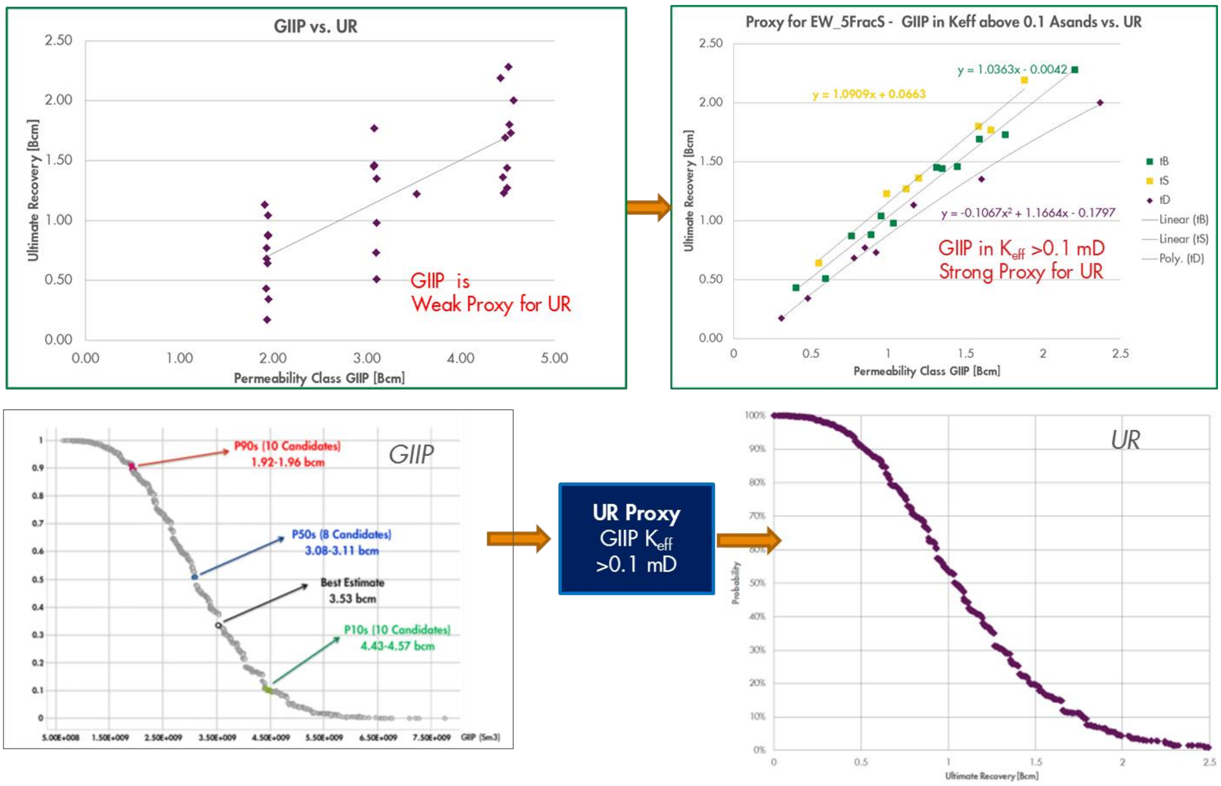


Fig 2: (Bottom-left): Cumulative Distribution function of In Place Volume scenarios. A select group of candidates were selected for dynamic simulation screening. (Top-Left): Dynamic simulation output of the candidate scenarios

with a spefic well and hydraulic fracturing design concept. wide uncertainty range for the relationship between the Initial gas in place and the expected ultimate recovery (Known fact in Tight gas). (Top-Right): Exploring the relationship between expected UR and the GIIP contained in cells with effective gas permeability > 0.1 mD. Colors show alternative top strcutre source for the scenarios. (Bottom-Right): Transforming GIIP CDF to UR CDF based on the proxy. The relationship was tested with blind tests (simulating other scenarios).

Surface-based reservoir modelling: Generating realistic geological heterogeneity for reservoir modelling and simulation

Carl Jacquemyn, Matthew D. Jackson, Gary J. Hampson
Imperial College London

Surface-based reservoir modelling is an approach that represents geological heterogeneity by surfaces that separate domains of different properties. All heterogeneity of interest (structural, stratigraphic, sedimentological, diagenetic, petrophysical) is modelled by a hierarchy of surfaces and the domains that they bound. of the resulting surface-based models are grid-free and lack the geometrical and spatial resolution constraints of models constructed using conventional workflows on a pre-defined grid. This enables users to (1) model near-vertical to overhanging features such as recumbent folds, (2) include small features in large domains, with length scales ranging across several orders of magnitude, and (3) preserve connectivity and continuity of baffles, barriers or high-permeability conduits. The resulting models can be used directly for flow simulation on adaptive tetrahedral grids that preserve input geometry without the need for upscaling. Surface-based reservoir models therefore provide a more faithful representation of heterogeneity than conventional grid-based reservoir models and provide a more reliable tool to compute static properties or dynamic behaviour.

Our approach aims to model all heterogeneity by its bounding surfaces. This also implies that within the volumes bounded by these surfaces, all petrophysical properties are constant and no further property modelling is needed. Building and assembling surface-based models takes into account all information about heterogeneity and translate it to surfaces and surface interactions.

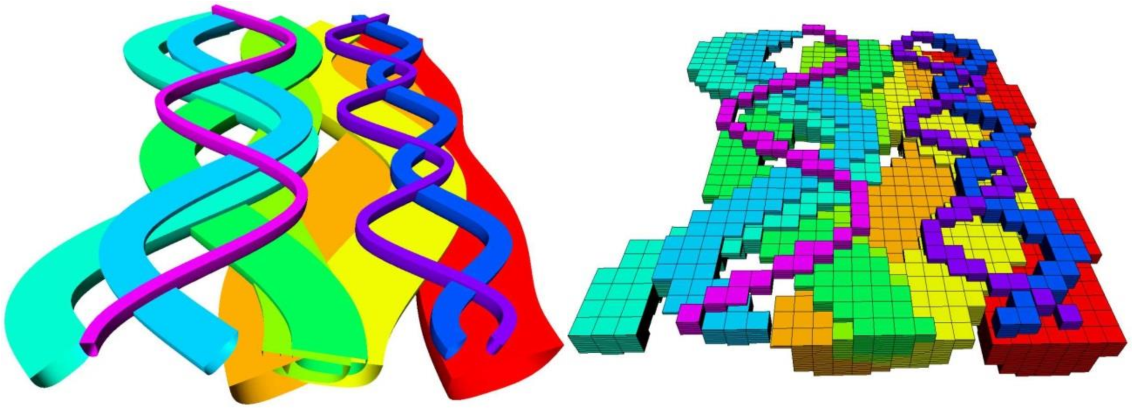


Figure 3 Difference between grid-free surface-based reservoir model (left) and a conventional cornerpoint grid model (right) representing the same channelised sediment-body geometries. Note the loss of continuity of thin channelised bodies in the grid model.

Model assembly relies on the information that is passed on with bounding surfaces. For every surface, metadata are attached that guide the automatic assembly of all surfaces, such that they bound closed, watertight volumes, and the assignment of facies or petrophysical properties to these volumes. For the assembly, three types of information are added to the surfaces: 1) surface-type information that describes the interaction with respect to other surfaces and volumes; 2) a hierarchy of surfaces that defines which surfaces and volumes are already assembled prior to inserting the current surface; and 3) the order of a surface, which defines surface ordering within one hierarchical level and groups surfaces that should be inserted together. Models are assembled by the consecutive subdivision of pre-existing volumes by one-or-more surfaces. The model volume is built from surfaces that represent the model boundaries. Subsequently the model volume is cut into one or more volumes by, for example, horizon, zone and fault surfaces. Next, any specific stratigraphic zone or fault block is cut into one or more facies volumes. Next a facies volume (e.g. fluvial sandstone) is cut by a surface to separate volumes of different properties (e.g. fine-grained and coarse-grained sandstone).

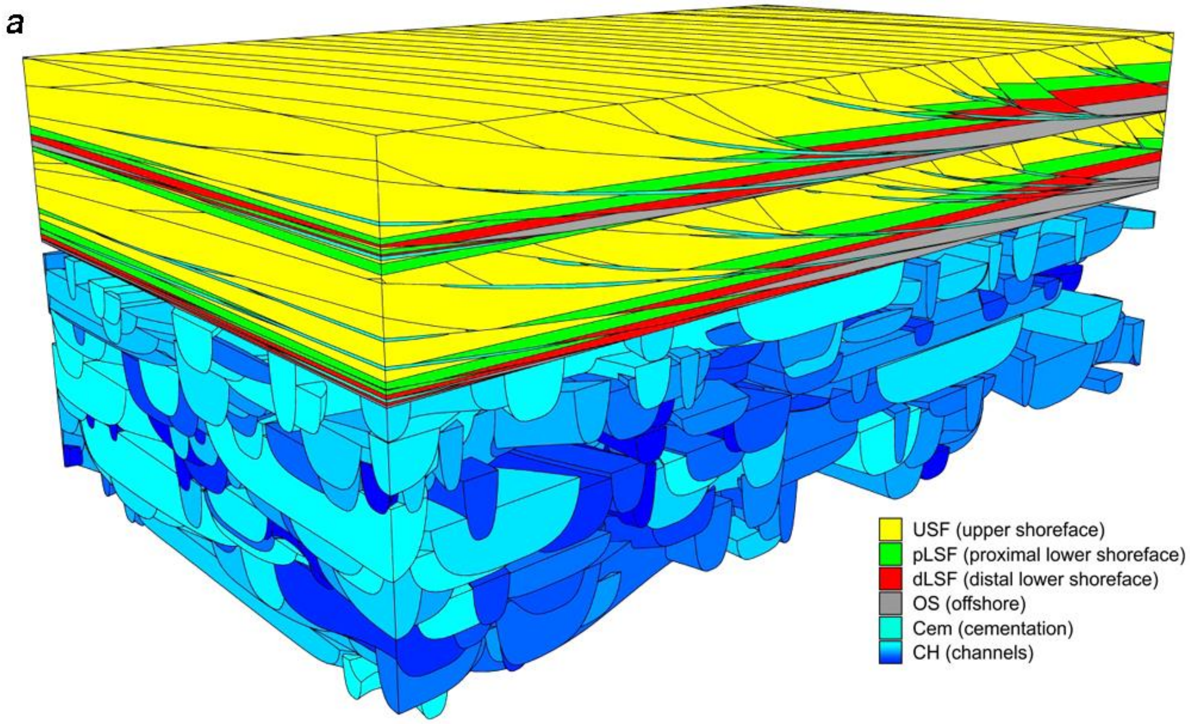


Figure 4 Surface-based reservoir model of channelised fluvial sandbodies, overlain by two vertically stacked shoreface parasequences. The shoreface parasequences are two different stochastic realisations (v.e.:5×).

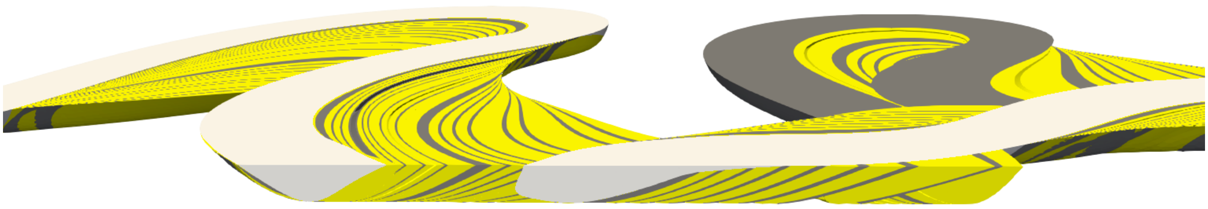


Figure 5 Cross section of a surface-based model representing meandering river deposits including lateral-accretion surfaces.

Grid-free surface-based reservoir modelling has four principal advantages over conventional grid-based reservoir modelling. Firstly, many aspects of structural geology, stratigraphy, sedimentology and geomorphology are conceptualised and visualised using surfaces, such that the approach is geologically intuitive and can leverage existing morphometric studies (e.g. Fig. 2 & 3). Secondly, a surface-based modelling approach accurately represents geometrical complexity and facilitates incorporation of heterogeneity over a wide range of length scales. Thirdly, the use of surface metadata allows automatic assembly of surface-based models, which opens up the opportunity of generating multiple realisations at the required level of detail. Static properties can be computed directly, without generating a grid. Finally, disposable unstructured adaptive tetrahedral grids are generated to perform dynamic simulations.

Virtual Outcrop-based analysis of channel and crevasse splay sandstone body architecture in the Middle Jurassic Ravenscar Group, Yorkshire, NE England

M. Mostafizur Rahman[1,2] and John A. Howell [1]
[1]*Department of Geology and Petroleum Geology, University of Aberdeen*
[2]*Department of Geology, University of Dhaka, Bangladesh*

The Jurassic deposits of the Yorkshire Coast have long been used as an analogue for the similar aged Brent Group Reservoirs in the North Sea. Recent advances in outcrop data acquisition techniques (Virtual Outcrops) have been applied to nine outcrops from a 40 km-long section of the coast. Outcrop data were collected by field observation including 45 sedimentary logs, lidar scanning, and UAV (drone) photogrammetry. In addition, 27 cored intervals from boreholes drilled by IFP in the late 1980's behind the Long Nab outcrop were also studied and a detailed geo-model was built combining outcrop and borehole data.

Within these sections ten different sandstone dominated architectural elements have been defined based on the lithology, geometries, storey pattern and nature of amalgamation. These includes five channelbody architectural elements: single storey small ribbon, single storey broad ribbon, tabular multilateral sheet, internally amalgamated multi-storey sheet, partially amalgamated multi-storey sheet, and five overbank architectural elements: ribbon crevasse channel, single splay sheet, amalgamated splay sheet, crevasse splay sheet complex, and wedge shaped levee.

The width and thickness of sandbodies varies between the element types. The channel bodies are 30 to >1655 m wide and 2 to 24 m thick with W/T ratio ranges from 5 to 105. The majority (77%) of the channel bodies were identified as multi-storey with average thickness of 8 m and width of 180 m while the single storey channel bodies are on average, 4 m thick and 50 m wide. The crevasse splays are >15 to >1285 m wide (mean 125 m) and 0.3 to 6.5 m thick (mean 1.3 m) with W/T ratio ranges from >50 to 550. Analysis of the vertical and lateral trends of the channel body dimensions indicate distinct differences between the formations within the Ravenscar Group and proximal to distal trends. The studies also provide new insight into the role of syn-sedimentary faults on the distribution of channel bodies.

Building a discrete fracture network model from vintage data in old oil fields: a case from the Southern Apennine hydrocarbon province

Paolo Pace[1], Raffaele Di Cuia[2] & Valentina Mascolo[2]
[1] *G.E. Plan Consulting*
[2] *Delta Energy Ltd*

The 3D geological modelling allows building a geocellular reservoir model that can be populated by calculating matrix and fracture properties and then used as input for flow simulation. Directional dependent permeability and porosity, that represent the fault and fracture properties, can be estimated via techniques of Discrete Fracture Network (DFN) modelling. The main objective of building a DFN model is to obtain the petrophysical properties of faults and fractures upscaled to a simulation grid. These properties can be then integrated with the matrix petrophysical properties to obtain a dual-porosity/dual-permeability reservoir model that is ready for flow simulation. In order to build a DFN model several steps have to be undertaken to extract the main input parameters for the modelling. It is then fundamental to calibrate with dynamic data the results of the modelling in order to be confident that the entire workflow and inputs are consistent with the dynamic behaviour of the reservoir. The building of a DFN model is an interactive exercise that is able to produce several scenarios that need to be validated or risked according to the knowledge of the reservoir and the amount and quality of the available data. DFN modelling is a challenging task due to the many uncertainties on the distribution and variability of the fracture network within the reservoir. So that all the available data have to be critically analysed to build a consistent and robust conceptual model.

The modern standard tools (image logs, multi azimuth acoustic logs, high-resolution 3D seismic, multi-azimuth downhole seismic) to detect the presence and to characterize fracture networks in boreholes drilled in 70's and 80's were not available. Therefore, the characterization of fractured reservoirs was very complex and at the same time very limited leading sometimes to a poor understanding of the reservoir behaviours and the underestimation of the discovery potentials.

Nowadays, the appraisal or redevelopment of old discoveries made in fractured tight reservoirs implies to deal with the lack of information regarding the fracture network characteristics and to handle with alternative approaches. In this study, a case of an old oil discovery, the Benevento discovery, made in fractured tight carbonates from the Southern Apennines of Italy is presented.

The Benevento field dates back to the early 70's. The reservoir units consist of Turonian-Lower Miocene fractured calcarenites and limestones at a depth of around 3000m below mean sea level and bearing both oil and gas. The source rock is related to the occurrence of organic-rich laminites deposited within a Cenomanian intra-platform basin. Top and lateral seals are represented by the Lower Pliocene shales and marls belonging to the Southern Apennines foredeep siliciclastic sequence, and the Miocene shaly and marly sequence of the Allochthonous units. The trap is structural defined by a faulted anticline pop-up structure belonging to the compressional structures of the buried Apulian thrust belt. The structure lies on the same trend of the largest and deepest oil fields in the region (Val d'Agri oil fields). This oil discovery has been re-evaluated and efforts for better understanding the fractured reservoir are needed before the new development drilling phase will take place.

The dataset is composed of three wells with cores and vintage well-logs, 2D seismic lines, drilling and test data. Regional geological information from wells in the surrounding and from regional seismic is also available together with data from present-day seismicity and stress field.
Within this context, an integrated approach was adopted with the aim to extract and squeeze the maximum amount of fracture information from the available data and to use a multi-scale and multi-scenario approach to produce a comprehensive fault and fracture conceptual reservoir model and to generate realistic drivers for the discrete fracture network modelling. Restoration and forward modelling were also used to simulate 3D strain distributions used to predict potential fracture trends and distributions for driving the fracture modelling. The results of the fracture modelling were then used to populate a dual-porosity/dual-permeability reservoir model and to help planning the design of horizontal development wells.

Novel 2D/3D seismic forward modelling of the seal bypass structure: an example from the Loyal field of the North Sea (Scotland UK)

Zhihua Cui[1], David Iacopini[1], Isabelle Lecomte[2]
[1]*University of Aberdeen,*
[2]*University of Bergen, Norway*

Abstract

Fluid escape pipes and blow out structures represent important seal bypass system (SBS) affecting the overburden. Most of those structures have been proven major fluid conduits that may reveal important hints on the fluid migration and fine-tuning our understanding on the main process controlling their genesis can be crucial in elucidating subsea hazard aspects during exploration stage. However, due to the lack of direct geological evidence and clear geophysical imaging, there are still uncertainties concerning they main architecture (root, conduit and seal). In order to contribute to the seismic interpretation of those subsurface structures, we propose a forward seismic modeling aiming at exploring the nature of certain seismic structure responses and architectures observed across the Loyal field (Shetland Basin) and using different petrophysics properties. We first build a 2D geological model with essential rock profiles and well logging data constrained. Then, we employ three approaches, i.e., forward modeling, ray-tracing analysis and time-to-depth conversion, to unravel and explore some of the main internal structures observed within the interpreted fluid pipe seal by-pass structures present in the Loyal field. We also build 3D models from two typical and identical pipes from seismic volumes, then modify the models with essential variation to fit most typical pipes. Afterwards, we explore the illumination distribution towards the targets, especially important and cared features. The results allow us to put some constrains on the origin and nature of some specific seismic features observed in the seal bypass structures: (i) the absorption effects in the conduit result in the lacking resolution in the internal-pipe and root structures, (ii) the upward deflections are almost formed by the real upward dragging intrusive material and (iii) the internal pipes are affected by low velocities related to fluid-rich solid material.

Introduction

SBS are structures that cut the sealing seal sequences vertically and allow fluid migrating horizontally into the overburden porous grid (Cartwright et al., 2007). The fluid escape pipe (Figure 1) is one kind of SBS that shapes vertical or sub-vertical structures cutting through the seal overburden reaching already or closely to the top layers forming termination. Details of them are still poorly understood, while the intrusive over-pressured mechanisms that have been proposed seem very complex and not single-factor influenced (Cartwright et al., 2007; Cartwright and Santamarina, 2015). Moreover, the lack of direct analogue outcrop information (e.g., analogue rock and well logging) makes seismic data the main subsurface source of dataset. Here, we aim to explore the geometrical and petrophysical situation of the fluid escape structures described in the Loyal field from previous seismic interpretation (Maestrelli et al., 2017), and through the utilization of ray-tracing test towards the conduits and time-to-depth conversion experiments, we explore the potential time pitfall when interpreting those structures.

The Loyal field is located 60-km northeast of the Faeroe-Shetland Trough (North Sea), which has experienced a complex evolutionary history in geology (Dore et al., 1997; Dore et al., 1999; Dean et al., 1999; Roberts et al., 1999). The main structural element from the seismic volume is the Mesozoic/Paleozoic Judd High in the southwest of the portion. The major seal for the reservoir underlying is the Top of the Lista Formation. The youngest overburden units observed are Mio-Pliocene turbiditic channelized sediments and contouritic deposits (Maestrelli et al., 2017). The Loyal field has no evident findings on basalt, but only clues of gas and sand intrusions based on the information from the BP industry report, which can also be supported by the stratigraphic chart.

Seismic Data and analogue well logging data

The area containing our simulation target within the seismic dataset is the Loyal field (North Sea, UK) and located in the southernmost part of the Faeroe-Shetland Trough, which is on the edge of the channel, to the north of Schiehallion, west Shetland. The data area covers about 15 x 17 km2. Only one well and well log dataset (204/20) could be used as well tie for the seismic dataset. This well logging provides us a reference property range and the

Lista Top Formation reference layer. The nearby VSP dataset proves that the velocity in our area of interest is between 1700 m/s to 2200 m/s and the tuning thickness is between 5- to 27-m.

Methodology

Seismic forward modeling has been performed following a method using ray-generated Point Spread Function (PSF) for convolution with an input reflectivity model, which directly and efficiently simulates PSDM-like images (Lecomte et al., 2003; Lecomte et al., 2008; Lecomte et al., 2016; Figure 3). The workflow performs standard ray-tracing and time-to-depth conversion experiments to explore the illumination responses to obtain the best imaging of highlighted features and to test the significance of some apparent pull-up pitfalls, respectively.

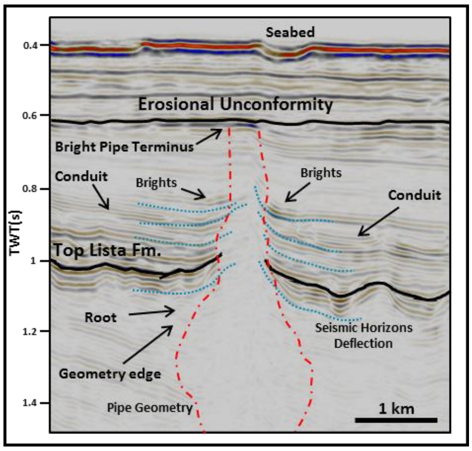


Figure 1: Interpretation of fluid escape pipe on real seismic images

Three-dimensional modelling of volcanic facies architecture; the application of virtual outcrops to aid stratigraphic interpretation and prediction

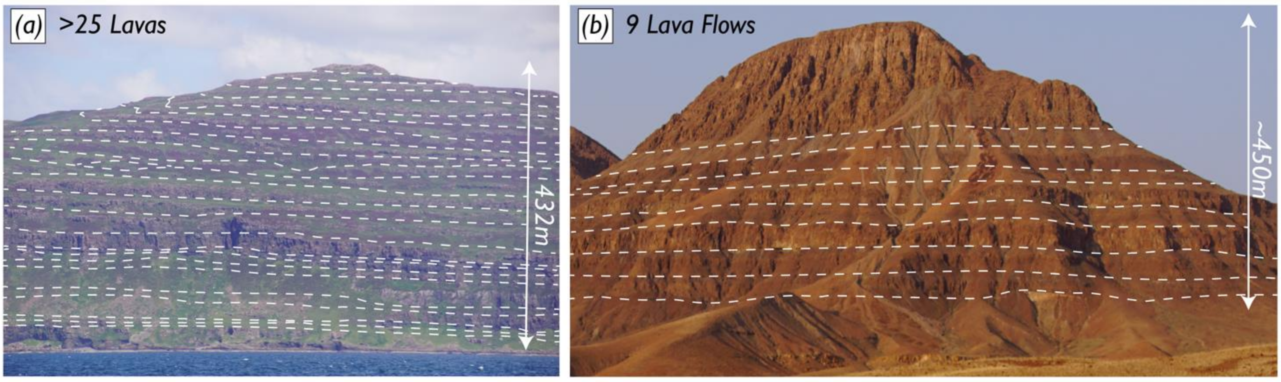
Jessica H. Pugsley[1], Malcolm J. Hole[1], John A. Howell[1], David W. Jolley[1] & Dougal Jerram[2,3]
[1]*Department of Geology and Petroleum Geology, University of Aberdeen*
[2]*Centre for Earth Evolution and Dynamics (CEED), University of Oslo, Norway*
[3]*DougalEARTH Ltd.*

Hydrocarbon exploration is increasingly focusing on more complex and historically challenging sedimentary basins, such as volcanic dominated rift basins.

Predicting the three-dimensional geometry of volcanic rocks, such as extrusive lava flows, is highly complex, though commercially critical when targeting sub or intra-volcanic reservoirs. Traditional lava stratigraphic architecture models have relied on low-resolution geophysical surveys or geochemical data to correlate lava flows. However, this can result in oversimplification of the lava stratigraphy. Through the use of onshore outcrop analogue studies from the Isle of Mull Lava Group and Namibian Southern Etendeka, we illustrate the vast range and complexities of lava field architecture.

The Mull Lava Group, part of the British Palaeogene Igneous Province (BPIP), exhibits a highly heterogenous stratigraphic sequence with a significant level of lateral and vertical variation. Individual lava flows range from <0.5 to 30 m in thickness (figure 1/a) and are laterally challenging to trace for further than 10 km2, partly due to faulting. Intra-volcanic sedimentary interbeds are almost entirely volcaniclastic in composition therefore equating to very poor reservoir potential. Syn- and post-lava emplacement faulting is extensive across the study area, prediction over fault planes is often uncertain. In contrast the Cretaceous Southern Etendeka of the Huab Basin represents a large laterally continuous sequence of flood basalt lavas with thicknesses ranging from 30 to >100 m (figure 1b). Lava flows from the Southern Etendeka have been correlated with flows in the Paraná Basin, Brazil, suggesting a prodigious lateral extent of 33,000 km2 (Jerram et al, 1999; Milner et al., 1995). Between individual lavas flows, intra-volcanic aeolian sand dunes are preserved.

Figure 1: Example locations from both case studies where 3-D virtual outcrop models have been constructed,



photos display the far larger scale of the Southern Etendeka when compared to the Mull Lava Group. (a) Over 25 flows can be observed from sea level to the top of Bearraich. (b) 9 lava flows are exposed in the upper Awahab section, the uppermost exceeds 100m with no upper crust preserved.

Extensive three-dimensional virtual outcrop models have been collected and constructed from Mull and Huab cliff sections. On Mull over 17km of coastal 3-D virtual outcrops capture the heterogeneous nature of this lava field. Detailed field mapping, logging and geochemical data are assisting in our understanding of the structure and evolution of this lava-sedimentary sequence. Within the Huab Basin, key locations were selected to produce 3-D virtual outcrop models. Analysis of the virtual outcrops using Lidar Interpretation and Manipulation Environments (LIME) and Petrel software has facilitated 3-D interpretation of volcanic and intra-volcanic sedimentary units, as well as dykes, sand injectates and faults. We present high-resolution 3-D architectural models from both case studies, which present two end members of flood-basalt successions due to their lava flow scale and intra-volcanic sediment contrasts. By comparing 3-D virtual outcrops for both case studies we have been able to generate a range of surface geometry packages, which can be applied to subsurface geometries.

Realistic geological modelling of complex discrete fracture networks

Pat Fothergill[1], Mark Cottrell[1], Lee Hartley[1], Simon Libby[1] and Robert Turnbull[1]
Golder Associates (UK) Ltd

Discrete fracture network (DFN) modelling is a widely used and valuable method for representing heterogeneity and compartmentalization in naturally fractured reservoirs. DFN models help to characterize dual porosity/permeability systems and reservoir anisotropy that cannot be accurately represented using simple geocellular models alone. They are also increasingly used to model the interaction of natural and hydraulic fractures in unconventional reservoirs and for helping to estimate stimulated rock volume and ultimate recovery. Nevertheless, complex fracture networks are often over simplified in field-scale static models, which in turn leads to greater uncertainty and poorer production estimates.

One of the first problems to overcome is the sheer number of fractures required to produce a realistic model. Even relatively small fields, with only moderate fracturing, require millions of discrete fractures to be modelled, which can be computationally difficult. This often limits the scales of fracturing represented in the reservoir model and/or restricts the size of area analyzed. However, recent advances in fracture modelling have enabled increasingly larger DFNs with greater numbers of fractures to be characterized. This paper will show examples of large-scale reservoir models, containing 100s of millions of fractures, which have been upscaled to produce a much more accurate and robust input to dynamic modelling.

Secondly, it is important to capture the interactions and intersections between different fracture sets in order to evaluate hydraulic connectivity and/or possible permeability barriers. In order to do this, it is important to honour the deformation history of the reservoir, generating fracture sets in the order they formed. This allows the terminations and cross-cutting relationships of each set to be more accurately modelled. A demonstration of a dynamic fracture growth model will be shown, to illustrate this latest development in DFN modelling.

Finally, it is imperative to relate fracture geometry and intensity to the structural style of the area and our conceptual understanding of how and where fractures are likely to form. The use of analogues in DFN modelling is extremely important, especially where there is poor or no seismic data to help constrain the interpretation. Fracture set orientations and intensities can be modelled in accordance with the structural domain and known style of deformation. Modelled results can then be compared with measured wellbore fracture data to achieve an acceptable agreement. This is an iterative process and is often the best way to generate fracture interpretations in new exploration areas with relatively little data.

The different DFN analysis techniques discussed in this paper are all based on geoscience principles and interpretations, ultimately leading to a more realistic geomodel and a better understanding of both the static and dynamic properties of the reservoir.

GSL CODE OF CONDUCT FOR MEETINGS AND OTHER EVENTS

INTRODUCTION

The Geological Society of London is a professional and learned society, which, through its members, has a duty in the public interest to provide a safe, productive and welcoming environment for all participants and attendees of our meetings, workshops, and events regardless of age, gender, sexual orientation, gender identity, race, ethnicity, religion, disability, physical appearance, or career level.

This Code of Conduct applies to all participants in Society related activities, including, but not limited to, attendees, speakers, volunteers, exhibitors, representatives to outside bodies, and applies in all GSL activities, including ancillary meetings, events and social gatherings.

It also applies to members of the Society attending externally organised events, wherever the venue.

BEHAVIOUR

The Society values participation by all attendees at its events and wants to ensure that your experience is as constructive and professionally stimulating as possible.

Whilst the debate of scientific ideas is encouraged, participants are expected to behave in a respectful and professional manner - harassment and, or, sexist, racist, or exclusionary comments or jokes are not appropriate and will not be tolerated.

Harassment includes sustained disruption of talks or other events, inappropriate physical contact, sexual attention or innuendo, deliberate intimidation, stalking, and intrusive photography or recording of an individual without consent. It also includes discrimination or offensive comments related to age, gender identity, sexual orientation, disability, physical appearance, language, citizenship, ethnic origin, race or religion.

The Geological Society expects and requires all participants to abide by and uphold the principles of this Code of Conduct and transgressions or violations will not be tolerated.

BREACH OF THE CODE OF CONDUCT

The Society considers it unprofessional, unethical and totally unacceptable to engage in or condone any kind of discrimination or harassment, or to disregard complaints of harassment from colleagues or staff.

If an incident of proscribed conduct occurs either within or outside the Society’s premises during an event, then the aggrieved person or witness to the proscribed conduct is encouraged to report it promptly to a member of staff or the event’s principal organiser.

Once the Society is notified, staff or a senior organiser of the meeting will discuss the details first with the individual making the complaint, then any witnesses who have been identified, and then the alleged offender, before determining an appropriate course of action. Confidentiality will be maintained to the extent that it does not compromise the rights of others. The Society will co-operate fully with any criminal or civil investigation arising from incidents that occur during Society events.

ROBERT GORDON UNIVERSITY, ABERDEEN

Health and Safety

There are no fire alarm activations planned for today, so in the event of an alarm activation, please make your way to the nearest fire exit.

In the event of an alarm activation, **please do not use the lifts**.

Room – N240

The nearest exit to this room is on the same level, at the back of the building. Assembly points outside the building are marked with green signage.

The nearest toilets are located at side of the atrium.

Room – N242

There are no fire alarm activations planned for today, so in the event of an alarm activation, please make your way to the nearest fire exit.

The nearest exits in this room are either at the top or bottom of the stairs. Assembly points outside the building are marked with green signage.

The nearest toilets are located out of the top door and across the corridor.

For First Aid assistance, please contact Reception on ext.**2277** or **2288.**