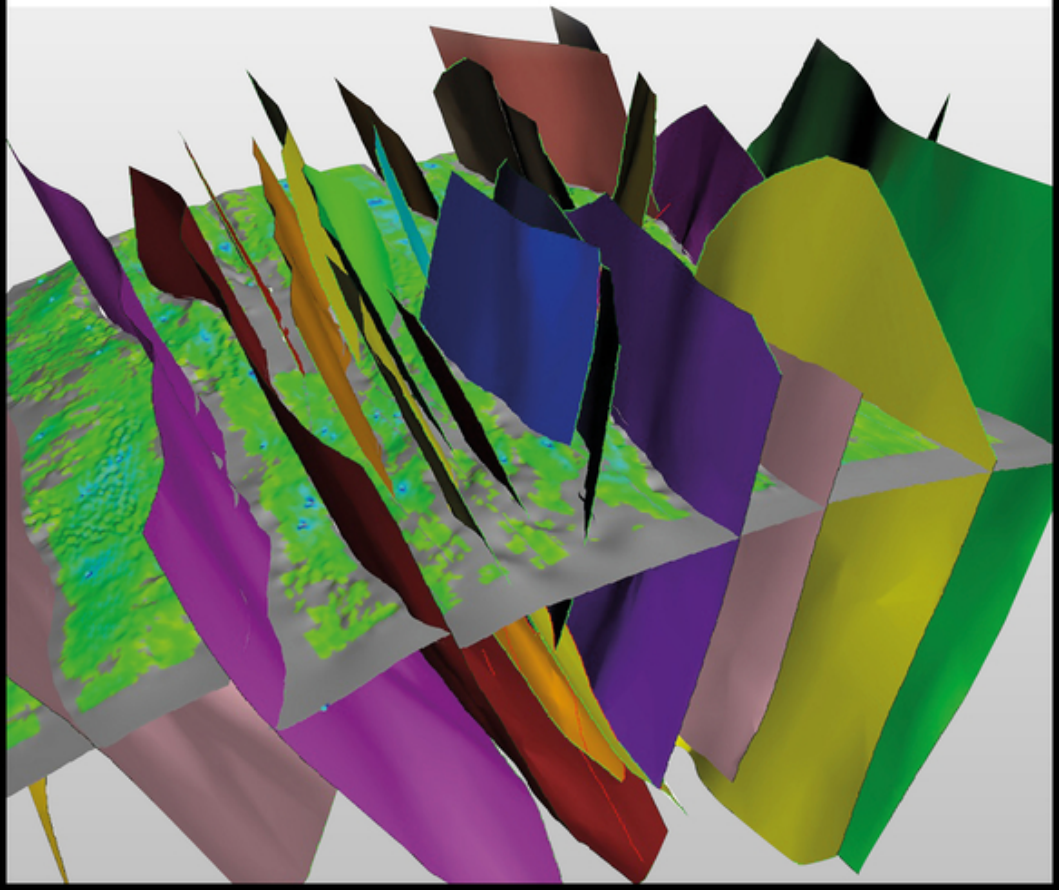
WILEY Blackwell

Steve Cannon

Reservoir Modelling

A Practical Guide



Reservoir Modelling

Reservoir Modelling: A Practical Guide

Steve Cannon
Principal Consultant
Steve Cannon Geoscience
UK

WILEY Blackwell

This edition first published 2018

Registered Office(*s*)
John Wiley & Sons, Inc., 111 River Street, Hoboken, NJ 07030, USA
John Wiley & Sons Ltd, The Atrium, Southern Gate, Chichester, West Sussex, PO19 8SQ, UK

Editorial Office
The Atrium, Southern Gate, Chichester, West Sussex, PO19 8SQ, UK

For details of our global editorial offices, customer services, and more information about Wiley products visit us at www.wiley.com.

Wiley also publishes its books in a variety of electronic formats and by print-on-demand. Some content that appears in standard print versions of this book may not be available in other formats.

Library of Congress Cataloging-in-Publication Data

Names: Cannon, Steve, 1955- author.
Title: Reservoir modelling : a practical guide / Steve Cannon, principal consultant (Steve Cannon; Geoscience).
Description: First edition. | Hoboken, NJ : Wiley, 2018. | Includes bibliographical references. |
Identifiers: LCCN 2017056087 (print) | LCCN 2017056889 (ebook) | ISBN 9781119313434 (pdf) | ISBN 9781119313441 (epub) | ISBN 9781119313465 (cloth)
Subjects: LCSH: Reservoirs–Mathematical models. | Hydraulic structures–Mathematical models.
Classification: LCC TC167 (ebook) | LCC TC167 .C36 2018 (print) | DDC 627/.86015118–dc23
LC record available at https://lccn.loc.gov/2017056087

Cover Design: Wiley
Cover Image: (Reproduced) Courtesy of Emerson-Roxar

Set in 10/12pt WarnockPro by SPi Global, Chennai, India

10 9 8 7 6 5 4 3 2 1

To all the Cannons, Nichols, Whitleys, Reeves and Watsons who have supported my geological studies, especially on the beach at Porthmadog and many other outcrops around the world!

Contents

Preface

This book has matured over 40 years of practical oilfield experience in mud logging and well site operations, from core analysis to sedimentology and reservoir modelling to field development: I have been fortunate to have had the opportunity to be employed in a variety of different roles for a wide range of companies and organizations. All of this has culminated in the opportunity to teach a successful course on integrated reservoir modelling, which forms the foundation of this book.

By profession, I am a geologist, by inclination a petrophysicist and I am a reservoir modeller by design. In reality, I promote the building of fit-for-purpose reservoir models to address specific uncertainties related to hydrocarbon distribution and geological heterogeneity that impacts fluid flow in the reservoir. A simple mantra for reservoir modelling, as in life, is 'keep it simple': we never have enough knowledge or data to rebuild the subsurface only to try and make a meaningful representation of the reservoir.

My background in reservoir evaluation gives me the experience to promote 3D modelling as a solution to most field development and production challenges as long as the question being asked is properly defined. Reservoir simulation projects are clearly designed to address specific issues, so should geological models, be it volumetric estimation, well planning or production optimization. This book is focused on the development of structurally complex, clastic, offshore fields rather than large onshore producing fields. This is largely because of the difference in well numbers and spacing; geostatistical software modelling products were developed specifically for these challenges. That the same tools have been expanded for use in giant onshore fields with a large well count has made 3D geo-modelling the tool of choice for reservoir characterization and dynamic simulation.

The person building a reservoir model can be part of a multidisciplinary team, the ideal situation in my view: or a geologist who knows how to use the software and is part of a linear workflow that starts with the geophysicist and ends with a reservoir engineer; in this case, each discipline often uses a different software product and there is minimal discussion at each stage of the process. Increasingly, the seismic interpreter can build the structural model as the first step and the geologist builds and populates the grid. Whichever situation you find yourself in, it is essential to take the rest of the stakeholders with you at each stage of the model.

The book does not promote one type of method over another or specify one commercial product above another; I am grateful to a number of organisations that have provided me with the tools of my trade, especially Schlumberger and Emerson-Roxar. My background as a consultant with Roxar Software Solutions from 2000 to 2008 defines my preference for object modelling of geological facies, rather than pixel-based methods, but in reality, the software tools available to the modeller allow a wealth of options. I would like to thank Aonghus O'Carrol, Dave Hardy, Neil Price, Doug Ross, Tina Szucs and all the people who have told me to 'RTBM' and play with the software. My thanks also to Steve Pickering and Loz Darmon from Schlumberger-NExT who encouraged me to develop the course and supported me during the delivery of the material to over 200 students worldwide and to Rimas Gaizutis who may recognize some of these ideas from working together in the past.

Finally, I am not an academic and this is not an academic treatise but a practical handbook. Many people will disagree with my philosophy when it comes to reservoir modelling, but when you are limited by: time, data or resources, pragmatism and compromise are the order of the day. A wise man once wrote, '*all models are wrong, though some can be useful*' (Box, 1979).

2018 *Steve Cannon*

1

Introduction

The purpose of this practical guide is to summarize the procedures and workflow towards building a 3D model: the principles are applicable to any modelling project regardless of the software; in other words, this is an attempt at a practical approach to a complex and varied workflow (Figure 1.1). What we are *not* trying to do in this book is to build detailed geological models of depositional environments but to capture the heterogeneity due to structure, stratigraphy and sedimentology that has an impact on flow in the reservoir.

The key to building a reservoir model is not the software; it is the thought process that the reservoir modeller has to go through to represent the hydrocarbon reservoir they are working on. This starts with a conceptual model of the geology and a diagram of the 'plumbing' model to represent how fluids might flow in the reservoir. Modern integrated modelling software starts with seismic input in terms of both interpreted horizons and faults and seismic attribute data that characterizes reservoir from non-reservoir and ends by linking to dynamic simulation; the so-called seismic-to-simulation solution. I have always been concerned that geophysicists and reservoir engineers might forget the geology that actually creates their oil or gas accumulation.

Wikipedia defines reservoir modelling as 'the construction of a computer model of a petroleum reservoir, for the purposes of reserves estimation, field development planning, predicting future production, well placement and evaluating alternative reservoir management.' The model comprises an array of discrete cells arranged as a 3D grid populated with various attributes such as porosity, permeability and water saturation. Geological models are static representations of the reservoir or field, whereas dynamic models use finite difference methods to

Reservoir Modelling: A Practical Guide, First Edition. Steve Cannon.

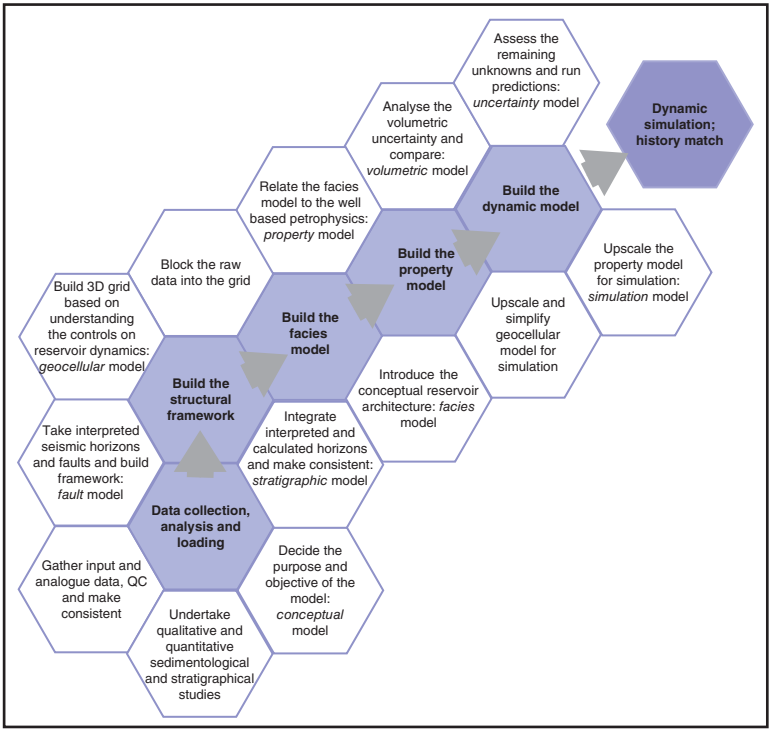


Figure 1.1 Reservoir modelling workflow elements presented as a traditional linear process showing the links and stages of the steps as outlined in the following chapters.

simulate the flow of fluids during production. You could of course construct a reservoir model using paper and coloured pencils, but analysis of that model is challenging!

Geo-modelling is 'the applied science of creating computerized representations of the Earth's crust based on geophysical and geological observations.' Another definition is 'the spatial representation of reservoir properties in an inter-well volume that captures key heterogeneities affecting fluid flow and performance.' However you define it, geo-modelling requires a balance between hard data, conceptual models and statistical representation. Whether you are working on a clastic or carbonate reservoir, the workflow is the same, although the challenges are different: in carbonate reservoirs, characterizing the petrophysical properties properly is paramount because diagenesis

will usually destroy any primary deposition controls on reservoir quality. We will look at carbonate reservoir characterization separately.

A few key statements should be made at the outset:

- Every field is unique and therefore has different challenges
- Every challenge will have a unique solution
- Every solution is only valid for the given situation and therefore …
- KEEP IT SIMPLE …… at least to begin with.

1.1 Reservoir Modelling Challenges

Building a model of an oil and gas reservoir is complex and challenging as much because of the variety of data types involved as the many different steps required. The process is made easier if you can establish why you are building the model; what is the objective of the model? Today, we generally build 3D geocellular models for volumetric estimation, dynamic simulation, well planning and production optimization or to understand the uncertainty inherent in any hydrocarbon reservoir. Above all, a successful 3D model aids in the communication of concepts and the interpretation of data used to characterize a potential or producing oil or gas field.

We model reservoirs in 3D because nature is three dimensional and because the reservoir is heterogeneous and we have restricted opportunities for sampling. Additionally, to understand flow in the reservoir, we need to consider connectivity in three dimensions, rather than simple well-to-well correlation. Having built a 3D representation of the reservoir, it can be used to store, edit, retrieve and display all the information used to build the model; in effect, a model is a means to integrate data from all the subsurface disciplines, so the data are not just stored in the minds of geologists.

Reservoir modelling is also a challenge because we are dealing with a mix of geological and spatial properties and also the complex fluids present in the reservoir. The data available to build a representative model are generally either sparse, well data or poorly resolved, seismic data. The resulting model is dependent on the structural complexity, the depositional model, the available data and the objectives of the project. Building a usable reservoir model is always a compromise: we are trying to represent the reservoir not replicate it.

The advances in computer processing power and graphics over the past 20 years has meant that geoscientists can build representative

models of a reservoir to capture the variability present at all the appropriate scales from the microscopic to the field scale. However, as reservoirs are complex, we need to be highly subjective about the scale at which we model and the level of detail we incorporate: a gas reservoir may well be a tank of sand but faults may compartmentalize that tank into a number of separate accumulations.

1.2 Exploration to Production Uncertainty

Even before the first exploration well is drilled on a prospect, a geologist will have estimated the likely volume of oil or gas contained in the structure; by comparing one field with another, a reservoir engineer may even have estimated a recovery factor. The volume estimated will have an upside and a downside to provide a range of values. At this stage, the volume range may have been calculated using deterministic or probabilistic methods, or a mixture of both, and will generally be quite a large spread. At each stage in the life cycle of the field, the median value and the range should ideally change in a predictable way as uncertainty is reduced through appraisal drilling and data acquisition (Figure 1.2). When there is sufficient confidence in the estimates, a development decision is made and a project can begin to spend real money! In reality, the evidence from many

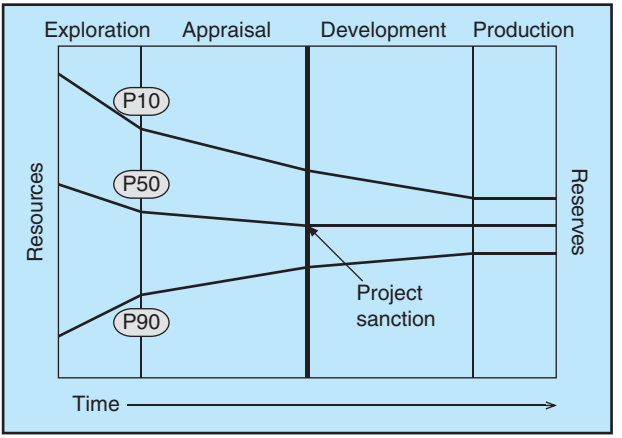


Figure 1.2 Idealized evolution of resources with time over the oilfield life cycle showing the reduction in uncertainty after each stage.

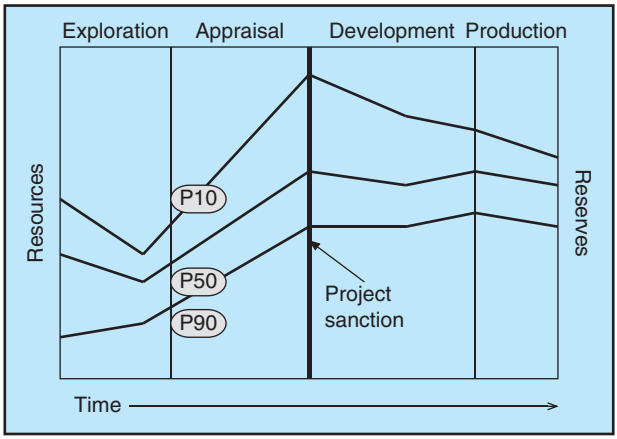


Figure 1.3 Actual example of resource change during appraisal and development of an oil or gas field; appraisal often continues after project sanction as too many wells may erode project economics.

different field developments is that the ranges in volume are always being revised to account for new data, new ideas or new technology. This often has the effect of delaying the timing of decision-making, especially in smaller fields, where the risk of getting it wrong can have a bigger impact on value (Figure 1.3).

In 1997, the UK government commissioned a survey to review the track record of field development in the UK sector of the North Sea with the aim of determining how reserves estimation changed from the time of project sanction to field maturity. Fields that were sanctioned between 1986 and 1996 and containing greater than 10 MMBOE were reviewed. This was done to establish the confidence the operator had in the estimated ultimate recovery they reported, the methods adopted to make the estimation and the major uncertainties in their estimation.

Until 1996, 65% of respondents said that they used deterministic methods to provide a single value with explicit upside and downside ranges; 53% reported using Monte Carlo/parametric methods, and 30% said that they adopted probabilistic estimation using multiple geological or simulation models: several companies use a mix of all the methods, which is why the percentages add up to more than 100% (Thomas, 1998). In the same survey, 30% of the respondents said that gross geological structure accounted for much of the uncertainty in the estimation of ultimate recoverable reserves; the remainder believed that the reservoir description accounted for the uncertainty.

For fields under appraisal, the level of uncertainty was greater than those in production and that, in general, the estimates tended to be pessimistic rather than optimistic.

While analysing the results of the survey, it became apparent that reserves estimates have varied by plus or minus 50% in more than 40% of the fields after project sanction; this was particularly true for fields where the estimates were based on deterministic models (Figure 1.4). The economic impact on field development cannot be ignored; 60–80% more wells were required to achieve the reported reserves estimates, together with very expensive retrofitting of equipment on offshore platforms. Many of the fields surveyed were compartmentalized, fluvio-deltaic reservoirs of the Brent Province that required significant additional investment over their lifetimes. With the increased use of 3D geocellular models over the past twenty years, one would anticipate an improvement in the estimation of in-place hydrocarbon volumes and the ultimate recovery of reserves. We only really know the ultimate recovery from a field when it has been abandoned, and even then someone might try to redevelop a field when the economic situation is improved.

It is important to realize that all fields are unique and that it necessary to understand the geology, the reservoir fluids, the data available and the development scenario proposed to maximize the economic return of the discovered resources. Resources only become reserves when an approved field development plan is in place and the money required to meet the development costs has been committed. It also helps if all the stakeholders, operator, partners and government bodies are in agreement with the objectives of the proposed development, not always a gimme!

1.3 Content and Structure

The chapters in this guide follow a general workflow from data QC and project management, structural modelling, facies and property modelling to upscaling and the requirements for dynamic modelling. Throughout, the recognition and handling of uncertainty at all stages is stressed, with some attempt made to deal with the issues.

- Chapter 2 reviews the basic data required to build a reservoir model and how to set up, QC and manage the project database.

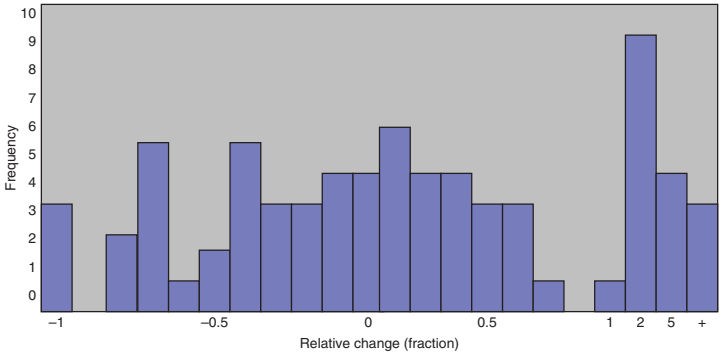


Figure 1.4 Histogram of the relative change in proven + probable estimates in ultimate recovery of oil over the period 1989–1996 for UK North Sea fields with reserves greater than 10 MMSTBOE. *Source:* Thomas (1998). Copyright 1998, EAGE publications.

- Chapter 3 discusses structural elements of a model including a review of the seismic interpretation and depth conversion, which are known to contribute most to volumetric uncertainty.
- Chapter 4 looks at the internal reservoir architecture and how the large-scale stratigraphic relationships are integrated into the reservoir framework.
- Chapter 5 takes a look at facies modelling; the different methods and the need for understanding the geological interpretation of cores and logs.
- Chapter 6 is focussed on modelling the main reservoir properties; porosity, permeability and water saturation. Carbonate reservoir description is also covered in this section.
- Chapter 7 discusses the role of uncertainty analysis in the static model and its impact on volumetric estimation.
- Chapter 8 looks at upscaling both the structure and the properties of a fine-scale geological model for dynamic simulation.
- Chapter 9 addresses some typical approaches to modelling specific reservoirs through a mix of case studies and examples.

This book is written from the perspective of a specialist reservoir modeller embedded in a subsurface asset team. As such, the modeller is responsible for taking the interpretations of each of the other specialists and melding them into a successful model to be used for volumetric analysis, dynamic simulation, well planning or production optimization. The key to this is being prepared to make compromises at almost every stage: the seismic interpreter should identify all the potential faults, and the sedimentologist should record all the possible facies, but each member of the team should be aware that not every detail can or should be modelled.

Some of the essential information needed to understand a reservoir for modelling is presented in Table 1.1: this also displays the multidisciplinary nature of a reservoir modelling project. All the subsurface disciplines are involved in defining what the project might achieve in terms of understanding a new field development and what uncertainties may still remain, whereas the petroleum engineers require volumes and production profiles to design the appropriate facilities to handle the hydrocarbon throughput.

One key element that is often neglected is the impact of imperfect or missing data; the known unknowns and the unknown surprises that manifest themselves as a field undergoes development; usually, the results of inadequate appraisal. It might be incomplete seismic

Table 1.1 List of key information required before starting a reservoir modelling project.

Drive mechanism	Fluid expansion, solution gas, aquifer and so on
Reservoir fluid	Dry gas, condensate, light oil, heavy oil
Reservoir framework	Normal faults, rollover anticline, thrust/slide
Reservoir architecture	Single tank, multiple stacked, compartmentalized
Trapping mechanism	Structural, stratigraphic, diagenetic
Depositional environment	Clastic alluvial, deltaic, marine; carbonate ramp/reef
Reservoir conditions	HPHT, LPHT, normally pressured, aquifer support
Data types and coverage	2D, 3D, 4D seismic; wells, logs, cores; pressure data
Development scenario	Offshore-fixed platform, FPSO, subsea tieback; onshore well spacing, storage tanks, pipeline

coverage or absence of core data with which wireline log properties can be calibrated; these types of unknowns can compromise any meaningful estimate of in-place volumetrics. Hopefully, as a project moves through appraisal towards sanction, the uncertainties are reduced through focussed data acquisition – but not always: beware of the asset manager who believes that additional data acquisition erodes the value of a project; this usually means that the project is marginal at best.

1.4 What is a Reservoir Model?

A reservoir model can be a series of two-dimensional maps and well correlations, an inverted seismic volume defining the distribution of lithology and fluids in a section or a three-dimensional geocellular grid that combines all of the well and seismic data (Figure 1.5). However the reservoir is represented, the ultimate objective is to describe the type and scales of heterogeneity that affect fluid distribution and flow in the subsurface. The value of any model is dependent on the data available to build it and the ability to *correctly* interpret that data: not an easy task! A useful reservoir model is a balance between hard data, conceptual models and the statistical representation of the subsurface.

Six reasons for 3D modelling:

- Incomplete information about dimensions, architecture and variability at all scales

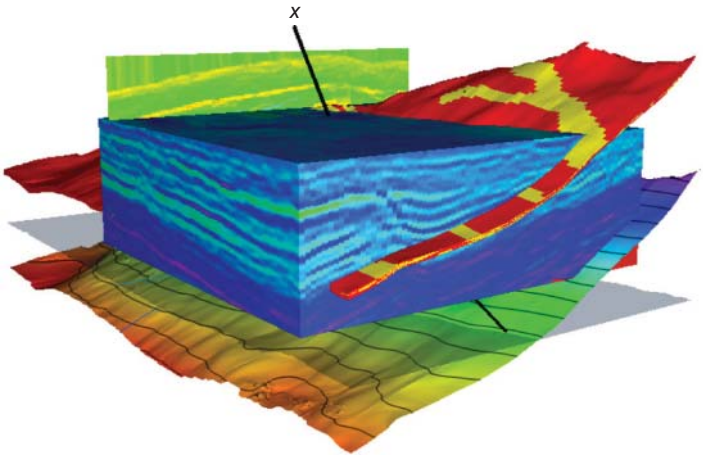


Figure 1.5 The many components of a 3D reservoir model from seismic interpretation to well planning. *Source:* Reproduced with permission of Emerson-Roxar.

- Complex spatial disposition of reservoir building blocks or facies
- Difficult to capture variability in rock properties and the structure of variability with spatial position and direction
- Unknown relationship between rock property value and volume of rock for averaging (scale)
- Relative abundance of static (point values for k, $ø$, S_w and seismic data) over dynamic reservoir data
- Convenience and speed.

What do we actual mean by the word 'model'? A *geological* model attempts to represent the relationship between different depositional elements of a stratigraphic sequence at a variety of different scales. This may be a *conceptual* model that seeks to capture the broad picture of our understanding in terms of the depositional environment or some hierarchical relationship between model parameters such as porosity and permeability. Mathematical models may be *deterministic* or *stochastic* depending on whether the input data can be associated with some degree of uncertainty: each deterministic model has only one realization, whereas a stochastic model may have many realizations, each honouring the statistical input and range of values. Models can be *map-based* (two dimensional) or *grid-based* (three dimensional). In the former, properties are varied only in the x and y directions using a number of different mapping algorithms to distribute the outcomes.

Grid-based models also vary in the z direction (depth) as defined by the geometry of the geological structure.

A *reservoir* model should be built to answer a specific aspect of the subsurface that impacts on hydrocarbon distribution or fluid flow. When designing a reservoir model, the ultimate purpose of the model must be defined: should it address the structural uncertainty of a prospect, the distribution and connectivity of reservoir units or perhaps the definition of a number of infill well locations? Each of these challenges will require a different approach and functionality; however, the key will be flexibility of both the ideas and the solutions that are generated by the modelling team.

To this end, the reservoir model should address the following:

- Reservoir envelope: top and base structure
- Reservoir compartments: fault geometry
- Internal framework: correlation scheme
- Reservoir architecture: facies model
- Petrophysical property distribution
- Volumetric assessment
- Retention of relevant fine-scale detail through upscaling.

Each step in the workflow or each phase of a study should have an agreed deliverable that defines the potential functionality of the model at that stage. The following uses are typical for a 3D model:

- Geoscience database and validation of input data
- Visualization of a mapped structure and associated 2D property maps
- Visualization of seismic attribute data and analysis for reservoir property modelling and architecture
- Deterministic 3D property model and volumetric assessment
- Integration of conceptual model with core constrained 3D facies model
- Well and/or seismic conditioned property mapping
- Volumetric sensitivity analysis
- Well planning and placement
- Geoscience input for dynamic simulation.

This approach requires maximum flexibility and functionality in the modelling workflow. The likelihood of achieving the objectives of any modelling project will be greatly improved by adopting a flexible workflow for the life of the project, together with a flexible and functioning

team. Do not believe that a single model will answer all the questions the asset manager will ask; different models for different tasks.

1.4.1 Reservoir Model Design

When designing a reservoir model, it is essential that the conceptual reservoir architecture be captured by the model and that the key structural and depositional elements have been correctly selected. If the design is to be successful, then the balance of determinism and probability should be carried through from the conceptual model to the statistical representation of the subsurface.

New technology in the oil industry tends to drive complexity, but this does not always ensure greater accuracy, which in turn may not meet the objectives of the model build. It is more important to identify the critical features of a field that will impact on the project objectives and to rank them in order of importance; this will aid in future uncertainty analysis of results. The key to a good reservoir model is to understand the scales of heterogeneity that impact fluid flow.

Ringrose and Bentley (2015) in their book *Reservoir Model Design* identify four important issues in model design:

1) *Is the field architecture understood in a way that can be readily translated into a reservoir model?*
2) *Are the correct structural and sedimentological elements of the field identified to achieve the model objectives?*
3) *Is the conceptual model carried through intuitively into the statistical component of the model?*
4) *Is the balance between determinism and probability fully understood and is the conceptual model honoured in the deterministic model elements?*

The field architecture is a combination of the structural and stratigraphic elements of the model: the faults, the seismic horizons, and the sequence hierarchy and flow units. If the geologist can draw the conceptual model, then the reservoir modeller can build a representation of that model. The conceptual model may be of the field structure, the depositional environment, the property and fluid distribution or a combination of all four. By combining the conceptual ideas and the hard data, and using the modelling software to specify the rest, will produce a representative model; the challenge is to get the right balance between determinism and probability. The ultimate test of a representative static model is 'does it look right'? Does the model capture

the geological concepts and the hard data in a way that is defendable when presenting the results to team members, whose input has been used to build the model, and management and partners?

1.5 The Modelling Workflow

The process of building a 3D reservoir model will always follow the same general workflow, regardless of the tools available to the modelling team. There will always be key 'milestones' in the project that will be passed during the process, and these often form a defined deliverable as described above. Input for the model comes in two broad types: 'hard data' such as well tops and horizons and 'soft data' such as the conceptual model or the relationship between a seismic attribute and porosity in a well. Both types of data are required to meaningfully populate a model that is representative of the reservoir under investigation.

The traditional linear workflow is slowly being replaced by a parallel approach ideally suited for the specialist working in integrated teams (Figure 1.6). Although each step is still undertaken, they are often done at the same time such that all disciplines contribute to the design and construction of the model. The simulation model should not be the last design step, but the first if that is reason for the modelling project.

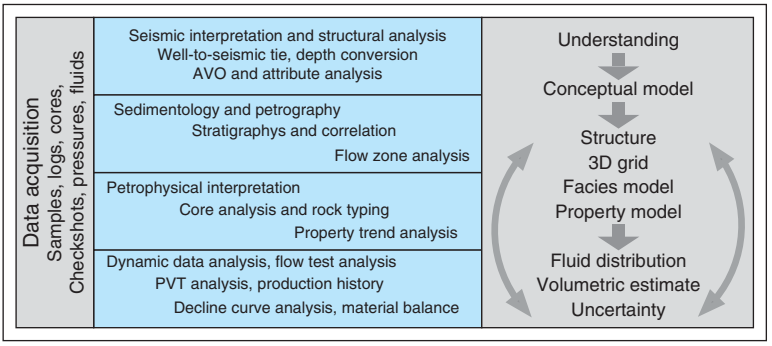


Figure 1.6 An example of a parallel workflow adopted by many companies for an efficient, integrated approach to reservoir modelling. The separate disciplines work together to design the model, analyse the available data and understand the uncertainties of the field under study.

The five major steps in the modelling workflow are as follows:

1) *Data collection, analysis and loading*
   - Gather input and analogue data, quality control it and make consistent.
   - Undertake qualitative and quantitative sedimentological and stratigraphic studies.
   - Decide the purpose and objective of the model: the *conceptual model*.
2) *Build the reservoir framework*
   - Take interpreted seismic surfaces and faults and build a framework: the *structural model*.
   - Integrate interpreted and computed horizons and make consistent: the *stratigraphic model*.
   - Build a 3D geocellular grid based on an understanding of the primary controls on reservoir dynamics: the *geocellular model*.
3) *Build the facies model*
   - Introduce the conceptual reservoir architecture: *facies model* and consider alternatives.
   - Decide on the method to use for distributing facies; object-based or indicator-based modelling or a combination of methods.
4) *Build the property model*
   - Relate the facies model to well-based petrophysics: *property model*.
   - Analyse the volumetric uncertainty and compare with existing volumetric assessment: *volumetric model*.
5) *Build the dynamic simulation model*
   - Upscale the property model for simulation: *simulation model*.
   - Validate the model against production history: *historic match*.
   - Assess the remaining unknowns and run predictions: *uncertainty model*.

Each of the steps will be described in the appropriate chapter, with an appreciation of the required input data, associated uncertainties and likely deliverable and its use.

Most reservoir modelling software products now include a workflow manager that is designed to capture the individual jobs in a particular part of the workflow so they can be updated at a later stage should new data become available. It is strongly recommended that these jobs and workflows are saved within each project.

1.5.1 Project Planning

Estimating the time required for building a model is something that relies on experience and the history of similar modelling projects. The complexity of the required model, quality and quantity of input data, and experience of the modeller all affect the time required. A Gant chart is a good tool to capture time frame information related to the project.

Perhaps the biggest, and most difficult, time element to estimate in building a model is data input/transfer, QC and clean-up. Experience suggests that 30–60% of time in a modelling project could be spent on these steps. Some consultants have identified this as a significant problem, and not only for geocellular modelling, and that they are required to spend time keeping their database clean and consistent. This investment of time and effort always pays a good dividend in the end.

A list of responsibilities that assigns team members to different tasks should be created. In a modelling project, particularly one that spans months and includes many team members, without a clear assignment of responsibilities things can often 'fall through the crack'. The assignments will vary on the level of detail according to the needs of the project team.

Quality control is a vital element of any project; it is always easier to correct the input data than try to edit the model results. It is also possible to estimate the degree of uncertainty if a quantitative quality control process is employed. One of the most time-consuming (and expensive) parts of a project is quality controlling the input data to a geocellular modelling application. An implicit QA/QC procedure will help ensure that all objectives and expectations are met. An audit trail is also an essential part of the overall project QA; the workflow manager can often provide a record of the work completed.

At one time, when I worked in a team that included a number of project engineers, I learnt the five rules of project management and the measure by which a project may be considered successful, Quality, Cost and Schedule:

1) *Define* – Goals, objectives, scope, constraints and risks
2) *Plan* – Activities, resources, duration, costs and schedule
3) *Implement* – Build the model
4) *Control* – Continual activity to QC the model and iterate as required
5) *Close* – Complete the project on time, on budget and to the scope.

A model needs to be planned carefully, in combination with the objectives and expectations and all other aspects determined in the scoping part of the project. The scoping part can be seen as guidance for planning the model. The success of any project can be judged on outcome in terms of quality, cost and timeliness of the result.

1.5.2 What Type of Model Are You Planning to Build?

It is possible to build many types of 3D model, all with a specific purpose in mind.

1.5.2.1 Prototype Model

Prototype models are quick-look solutions; they maybe coarse-gridded with only a deterministic approach used for modelling the properties. This prototype model can be placed into the simulator and inconsistencies and uncertainties determined in a short time frame, ideal for assessing initial volumetrics. It is always worth considering building a prototype model; this may answer many important questions, such as grid orientation, direction of the flow, is heterogeneity important in my model, which faults are important for the flow? Do not forget why this model was built and never let it be used for further analysis.

1.5.2.2 Full-Field or Sector Model

Is a full-field model needed to answer a question or can a sector model provide all the information? Often there is an automatic assumption that a full-field model is needed, but if reservoir heterogeneity is a key factor, the model can become very large. These enormous models are hard to handle in any software; loading, saving, visualization and so on will take longer. A solution is to build a sector model; the finer scale model will be smaller in size and can be used to answer questions such as horizontal versus vertical permeability (K_v:K_h ratios).

1.5.2.3 Deterministic or Stochastic

If a lot of well data are available, a deterministic model should be considered. This can quickly answer some basic questions. If a more advanced model is required, a stochastic model is the way to go. If heterogeneity is important to the flow, a stochastic model is preferred. With a stochastic model, it is also possible to create multiple realizations; a deterministic model will give only one answer. Often a deterministic model is used in the prototype-modelling phase.

1.5.2.4 Uncertainty Model or Multiple Scenarios

Multiple scenarios are different representations of the model designed to test a range of uncertainties. The input settings are changed for different interpretations giving a series of different outcomes. For example, you can change the direction of the channels or experiment with different target volume numbers. This approach can also be used to rule out certain scenarios.

1.5.2.5 Building the Simulation Grid First

If the team is closely aligned, then it may be preferable to build a reservoir simulation grid first. The uncertainties of the grid, such as orientation and grid size, can be determined beforehand; the coarse scale grid can then be refined and used as the fine-scale model. The advantage of following this method is that the fine-scale grid is always aligned with the coarse scale grid, so no upscaling artefacts are introduced. The process is also called *down-gridding*.

Always remember that all models are 'wrong', but some are useful!

1.6 An Integrated Team Structure for Modelling

The advantages offered by working in an integrated team for communication, project management efficiencies and ultimate results, both technical and commercial, cannot be stressed enough: a well-lead team with definable objectives should always be a more effective organization than individuals working alone or a traditionally structured organization.

A good team has the following drivers:

- A shared vision of the ultimate objective – maximizing productivity
- High levels of trust between individual members
- A clear definition of quality and a means of measuring it
- Realistic goal setting and measurement
- Group rewards tied to performance.

A team will perform well when there is synergy between members, and tasks that generate meaningful challenges will lead to better problem solving. Teams generally fit into two functional categories: *permanent teams* and *task forces*, which are structured either as *hierarchical organizations* or as a *peer group* with leaders who are often appointed or evolve (self-selecting) for different phases of a project.

There are a number of ways that different companies have structured their teams, depending on company culture, country of operation or project objective. The benefits of any approach should outweigh the costs of doing work in a different way, including costs associated with the change process. Following are examples of the ways in which companies have chosen to operate:

- *Employee teams:* Traditional in-house multidisciplinary teams, often organized in an hierarchical structure.
- *Partnerships:* Formal arrangements with another company to jointly undertake a project.
- *Strategic alliance:* Usually with a service provider who delivers a solution based on the company vision.
- *Outsourcing:* Commissioning a part or the whole solution through a third party.

With respect to reservoir modelling studies, both strategic alliances and outsourcing of projects have become increasingly a feature of company workflow. Both models lead to closer working relationships between companies and service providers with the expectation of reduced costs and more efficient work practices designed to limit duplication of effort. For these operational changes to be successful, a strong partnership or alliance must have the following:

- A joint vision or alignment of purpose
- A period of detailed planning before implementation
- Management commitment and team acceptance of the partnership
- Strong complimentary skills between partners and team members
- Clearly defined roles and responsibilities
- Commitment to the long term – at least the expected length of the project
- Common corporate and personal aims and objectives – a common culture
- Well-developed interpersonal skills amongst the team and its leaders

The changes that are needed to successfully move to a team-based work culture require that the management structure also change. The traditional hierarchical structure is dependent on close control of strategies and tasks from above: both functional and operational micro-management. The new approaches demand that the team is charged with managing their tasks such that they are in line with the

greater strategy set by the upper management and may even have had an influence in their design.

Consider the project where a different contractor company represents each discipline: the seismic interpretation, the geological concept, the petrophysics and reservoir engineering. The reservoir modeller receives the different inputs and builds a model using the data provided and the engineer turns round and states that 30% of the known gas has vanished! The new top structure map has been incorrectly depth converted using only development wells, so there is no offset data to control the flanks of the structure. Pity the poor project manager who has to sort that one out!

1.7 Geostatistics

Geo-modelling is also often termed *geo-statistical modelling* and therein lays the problem: geostatistics was developed in the mining industry (Krige, 1951) where the analysis of regularly spaced boreholes gave a means to establish the spatial variation of a property, a precious mineral usually. This is the origin of the method known as *kriging* whereby the spatial variation of a property can be *deterministically* mapped. The application to the oil and gas business has been less straightforward. Appendix I will give a review of geostatistical methods, but a few basic terms and conditions are required to give context to the rest of the discussion.

Statistical models have an information content that can be used either to reject a hypothesis or to predict a result, with an estimate of the associated error. Chesil Beach on the Dorset coast of England is 29 km long and 200 m wide and 15 m high and is composed of flint and chert shingle that varies predictably from pea-sized grains in the west to orange and larger sized cobbles in the east. The beach was formed at the end of the last ice age as a barrier bar in response to the Holocene (Flandrian) sea level rise.

The average mass of a pebble on the beach is 0.611 kg, which is a *statistic*. A single pebble collected from the beach is a *specimen* and a random selection of pebbles is a *sample*; all the pebbles on the beach are the *population*, but the average of the population is a *fact*, not a statistic. So a statistic is an *estimate* of a property based on a sample of the population, and the *quality* of the statistic is dependent on the *size* of the sample and whether it is *representative* of the population.

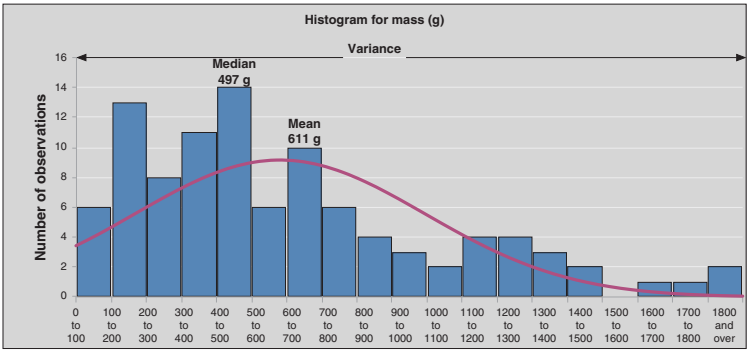
A *random variable* is a specimen or property drawn from the population and will have a series of possible values with a given set of probability of occurrence. If the number of possible outcomes is finite, then it is called a *discrete* random variable; if the number of possible outcomes is infinite, then it is termed a *continuous* random variable. In the world of geo-modelling, facies or lithology would be a discrete variable and porosity a continuous variable.

A property maybe described in terms of *mean* value, *variance* and *standard deviation*. The mean is the arithmetic average of the data; the variance is a measure of the spread between values in a data set and the standard deviation is the square root of the variance. Variance is dependent on volume; the more data, the better the statistical validity of the result. The *coefficient of variation* is the ratio of the standard deviation to the mean and is used to describe the shape of a positive distribution of data. The *mode* is the value that occurs most frequently in a data set and the *median* is the midpoint of the values when arranged in ascending order (Figure 1.7).

Probability is the measure of the likelihood that a given outcome may occur; in other words, the chance of a particular value or specimen being sampled. The probability distribution can be described as a cumulative distribution function (CDF) or a probability density function (PDF), either being used to predict an outcome. The probability distribution can be compared with theoretical models such as the *normal* or *Gaussian* distribution.

Stationarity is the property of a set of data that lacks a distinct trend: the mean variance and variogram are constant and relevant to the entire study area (Deutsch, 2002). In other words, the descriptive statistics of a property are the same wherever that property is sampled in the whole population; the mean and variance of the property are *independent of location* and should therefore be uniformly variable – 'heterogeneously homogeneous'. When modelling reservoir properties, the data should be stationary over at least the inter-well area for the results to be valid. Any evidence of vertical or lateral trends in the data must be removed before applying the chosen modelling algorithm.

The software products available for geo-statistical modelling provide the user with a number of tools for generating a representation of the heterogeneities in the reservoir. The two main methods are *pixel-based* models that use correlation structures determined by *variogram* models and *object-based* models that are defined by the geometry of typical geological bodies. These different methods arose



Variable: mass			
Count	100	*Minimum*	62
Mean	610.77	*Maximum*	1834
Mode		*Range*	1772
Median	497		
Variance	189,970.07788		
Standard deviation	435.85557		
Mean standard error	43.58556	*Geometric Mean*	457.50518
Coefficient of variation	0.71362	*Harmonic Mean*	316.92499

Figure 1.7 The statistical analysis of 100 beach pebbles displayed as a histogram and used to describe simple statistical nomenclature; includes a normal distribution curves and tabulated results.

from different geostatistical schools and France/America and Norway, respectively. *Multi-point* statistical models use a training image as well as a variogram to incorporate the geological information. Pixel-based modelling was developed from the original concepts of the mining industry. In Norway, object modelling became the norm to represent fluvio-deltaic channels in the major Middle Jurassic reservoirs of the North Sea. Most software products allow for the construction of *composite* models where reservoir bodies might be distributed in a background of non-reservoir deposits. The distribution of reservoir properties such as porosity uses the spatial variogram as the means to populate the model. Geostatistical modelling requires a *seed* value that is a randomly generated number used as a starting point for the process; each time the process is run, the seed may be changed or kept constant by the user.

Seismic data are increasingly being used to condition both facies and property models, especially where well data are sparse. Different methods have been developed to integrate seismic interpretation model reservoir surfaces and bodies. Kriging is commonly used to map a seismic horizon from well data; however, if an external drift is applied to the kriging algorithm, a series of equiprobable outcomes can be generated, while the surface is still tied to the well location. This is a *stochastic* method commonly used in depth conversion of seismic horizons. *Co-kriging* has been developed to integrate data from different sources such as porosity and a seismic *attribute*, such as acoustic impedance.

1.8 Data Sources and Scales

We get our hard data for modelling from the wells and seismic interpretation (Table 1.2), but this can be enhanced with analogue data from nearby fields, regional studies and published information on similar depositional environments. Fieldwork studies are also a great way of showing non-geologists the challenges associated with modelling facies and properties at different scales of investigation.

The vertical resolution of seismic can be anywhere between 10 and 50 m depending on the quality of the data and the complexity of the overburden. Compare this to the vertical resolution of wireline log data at 15 cm and petrographic data $<1\,\mu$ (Figure 1.8). This is the perpetual challenge for the reservoir modeller especially when trying to consolidate permeability data from core, log and well test data;

Table 1.2 Data sources for modelling.

Static data	Application
Seismic (2D and/or 3D)	• Interpreted horizons, discontinuities and faults • Acquisition parameters, processing
Vertical seismic profile Checkshot data	• Velocity model, seismic calibration • Synthetic seismograms, time/depth calibration
Velocity calibration	• Depth conversion
Wells	• Coordinates, depth control, deviation, drilling history • Well pattern and development history, well stock
Cores and core analysis	• Sedimentology, petrography, environment of deposition • Porosity, permeability, grain density, fluids, shows • Petrophysical core-to-log calibration, depth shift
Mud log	• Bulk lithology, hydrocarbon shows and kicks • Drilling history and parameters, mud losses, pore pressure
Wireline logs Dipmeter/image logs	• Petrophysical interpretation, porosity, water saturation • Log character and depositional environment • Well correlation, reservoir zonation, sequence stratigraphy • Structural coherence, faults, fractures • Sedimentological interpretation
Conceptual model	• Structural interpretation, depositional environment, diagenetic alteration
Seismic attributes	• Inversion, AVO anomalies, geo-body identification
Dynamic data	
Well test PLT RFT	• Inflow potential, flow rates, permeability, barriers, reservoir pressure, fluid recovery • Producing intervals, pressure gradients and fluid contacts
Production history	• Reservoir behaviour, material balance, production profiles
Fluid samples	• PVT analysis, formation water sample

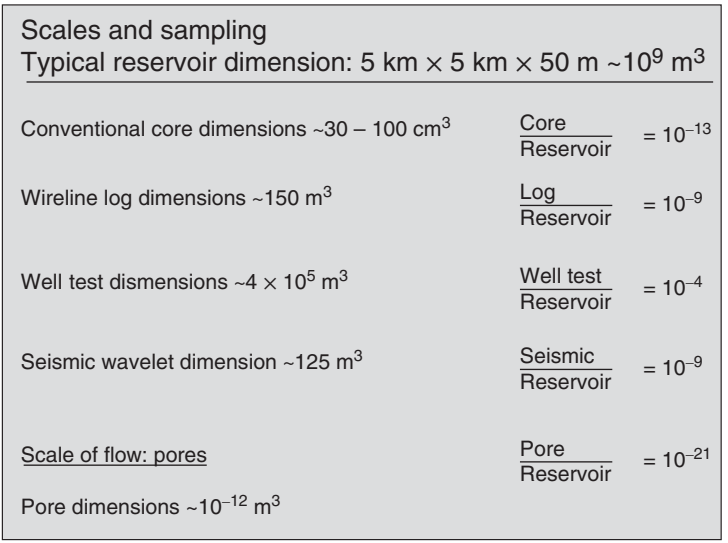


Figure 1.8 The scales of investigation of different types of data found in a reservoir study compared with the overall typical field size.

of these, only the well test permeability is approaching reality. It is a well-recognized observation that geologists and petrophysicists tend to underestimate high perms and overestimate low values because of the simplistic methods adopted in porosity–permeability correlation.

Seismic data are the primary source for horizon and fault input to the reservoir model. While we like to think that the interpreter has correctly picked the top reservoir horizon, this is often not possible due to the nature of the seismic response, and often a near top structural surface is provided. Faults data are also subject to picking difficulties as the seismic quality often deteriorates towards a discontinuity. We will look at the challenges of interpretation and depth conversion later, but issues abound with respect to quality and resolution of seismic.

Well data give the modeller the high-resolution data lacking in seismic, but because of the limited number of wells and the cost of data acquisition, we generally have incomplete sets of data (Table 1.2). Exploration wells are often not cored and may only have basic wireline logs, while production wells may have measurement/logging while drilling (MWD/LWD) data only. Well planned appraisal or development wells will command the most comprehensive suites of logs and cores and provide the high-quality post-well analysis needed

for detailed geological and petrophysical interpretation. Mud logs, cores and core analysis data are required to calibrate the wireline information.

Wireline logs and MWD/LWD logs provide a continuous, high-resolution record of the well penetration, including non-reservoir intervals, essential for depth conversion of seismic horizons and for unravelling large-scale geological sequences. Information from dipmeter and image logs aids in structural interpretation and sedimentological analysis of sequences. Other wireline measurements that should be routinely made are reservoir pressure and fluid sampling. Comprehensive pressure gradient information is used to delineate different reservoir layers and fluid distribution and leads to a better understanding of sand body connectivity.

1.9 Structural and Stratigraphic Modelling

The structural model is built from the depth-converted seismic horizons and fault data, generating a reservoir framework. This is combined with the internal reservoir layering that incorporates the stratigraphic component of the model. The structural model is often designed with a gross tectonic interpretation in place reflecting the interpreter's understanding of the regional structural history; in extensional basins, normal faulting is expected, whereas in compressive settings, reverse faulting and slumping might be predicted. Understanding the gross depositional environment of the interval drives the internal layering of the reservoir zones, leading to stratigraphic correlation and hierarchy. With the structural and stratigraphic models defined, the fine-scale geocellular model can be created.

1.10 Facies Modelling

A facies model captures the reservoir variability based on the sedimentological analysis of the core and wireline data, combined into a conceptual model of the reservoir depositional environment. The main reason to build a facies model is to condition the subsequent property model; each facies should have porosity and permeability distribution that is different from the other facies. This could be as simple as good sands, moderate sands and poor sands. If the

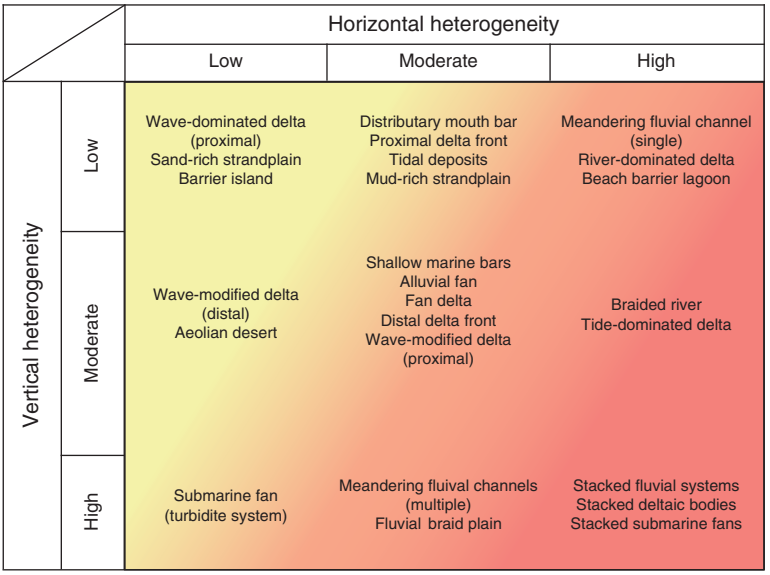


Figure 1.9 A matrix of horizontal and vertical heterogeneity classified by depositional environment. *Source:* Tyler and Finley (1991). Copyright 1991, SEPM (Society for Sedimentary Geology).

reservoir quality can be attributed to specific geological bodies or environments, then representative heterogeneity can be introduced into the model (Figure 1.9). Depending on the distribution of facies, the modeller has a choice of using *pixel-based* or *object-based* modelling methods: where the facies form a mosaic pattern, such as floodplain or carbonate shelf, pixel-based, indicator simulation may be used, whereas channel or shoal bodies might be characterized using object-based modelling. Either way, geology will be built into the model and reservoir connectivity might be captured better, as well as populating non-cored sections of a well.

1.11 Property Modelling

I prefer to use the term *property modelling* rather than *petrophysical modelling* because that has a different connotation for petrophysicists. Property modelling is about capturing the fine-scale distribution of porosity, permeability and water or hydrocarbon saturation in the

geocellular model. In fact, only porosity should be stochastically modelled, as permeability is usually a function of porosity or rock type, and water saturation should be distributed through a height above free-water level relationship. Where a robust facies model exists, then the reservoir properties should be directly related to reservoir architecture. Another topic for debate is the use of net-to-gross ratios and petrophysical cut-offs; I do not agree that either is necessary if a facies model is the foundation of the property model. Another issue in property modelling is whether to use 'total' or 'effective' properties; as the reservoir model represents subsurface conditions, I believe only 'effective' properties should be used. There will be a much fuller discussion of these topics in a later section.

The final geocellular model should always have the right balance between deterministic data, aspects of the model that are known by the modeller, and probability, those unknown knowns that are specified by the modelling software. Whether a well has sampled all possible facies or how they are distributed is more often a function of the probability specified by the modeller.

1.12 Model Analysis and Uncertainty

Before building a model, the input data are analysed for statistical content so that it might be used 'correctly' to populate a model. The results must also be analysed as part of the quality control process; the term *garbage in-garbage out* has never had more meaning than in statistical modelling. The input and output statistics should be compared in terms of mean values and standard deviation; however, if any trends or conceptual ideas have been applied to control property distribution, it is unlikely that the properties will match. There is a common misconception that the well data should explicitly be recreated through the whole model; this will only be true if a deterministic model is built using well data alone.

Generally, the static model will be used for in-place hydrocarbon volumes estimation or connected drainable volumes. However, using stochastic rather than deterministic methods allows the modeller to build multiple realizations of any given scenario. Scenarios are user-defined and could represent differing conceptual ideas, such as channel orientation or top reservoir structure; these would be deterministic uncertainties. The different realizations are the results of stochastic uncertainty within each scenario. By ranking these multiple

Table 1.3 Typical list of products from a reservoir modelling study that may be requested by a peer reviewer.

Maps	2D top reservoir map with existing and planned wells as well as other relevant cultural information
Correlation panel	Panel showing stratigraphic tops, zone model, fluid model and property curves
Histograms	Log versus upscaled log versus model histograms and summary statistics for whole model and for key zones
FWL's, GOC's, segments and so on	Show formulas and applied contacts – as well as ranges in contacts. Show segments and reasoning behind their definition. Note if there are different contacts used in different fault blocks or segments
Previous work and studies	List previous work and studies and mention their relevance and impact on current project
Maps	Gross, Net, Por. Vol., and Hydrocarbon thickness maps for total reservoir and individual reservoirs (if stacked reservoirs) extracted from model with log-derived averages (from petrophysical interpretation) plotted as well attribute
Maps	Top reservoir and intra-reservoir maps showing fault throws and well tops
Cross sections	4–6 cross sections through model showing key structural features, zones and fluid contacts. 4–6 cross sections showing input surfaces as well as final horizons, especially in faulted and pinch out areas.
Maps	Other relevant maps, used in modelling: AI, EI, PR and so on
Maps	Map out areas of field that are at or below tuning thickness – to facilitate discussion on how this issue has been handled
Formulas	Show formulas and their origin. Derivation of formulas must be reviewed and stored
Maps and X-sections	Show relevant property maps and X-sections
Uncertainty matrix	Matrix listing all parameters for which significant subsurface uncertainty is attached as well as high, mid and low estimations of range (modelling cases sheet can be used as template)
Volumetrics	Show table of volumetrics – historic data to be shown?

realizations, it is possible to identify specific cases representing low, medium and high outcomes or P90, P50 and P10 results.

Never forget 'all models are wrong, some are useful!'

1.13 Upscaling

Upscaling is finding the single property value that best represents the heterogeneity of a group of cells in the fine-scale model to be used in a coarse-scale simulation grid. The challenge is to maintain the content of the fine-scale model in the upscaled grid; this is especially true of the different scales of heterogeneity that will impact on production and recovery of hydrocarbons. Even with the increasing power of modern computers and parallel processing, it is seldom possible to run dynamic simulation on a fine-scale, full-field model. When a reservoir engineer is initializing a dynamic model, he is trying to maintain the total pore volume of hydrocarbons. To achieve pore volume correspondence, a simple summation method is used; however, when it comes to flow in the model, different permeability upscaling methods are required, and these should be based on well test data and production history (Table 1.3).

1.14 Summary

Reservoir modelling is challenging but also rewarding. This is especially true for the geologist who has come up with a conceptual model of a reservoir and has then been able to build a model that captures all of the ideas and hard data and is ultimately a tool for the evaluation and development of an economic asset. It is a worthy mantra to repeat, 'If you can draw the reservoir, I can build it.'

2

Data Collection and Management

Data management is probably the most important part of any modelling project. About 50% of the project schedule is spent on preparing data for loading and checking for inconsistencies. The quality of input data is the essential element of a modelling project; if there are any inconsistencies in the input data, they will show up in the end result and at every intermediate modelling step. It is always easier to correct the input data than to try and edit the results of modelling.

First define what data are available and what can be achieved with it, before starting the modelling project. Many companies will have a set of operating procedures that attempt to standardize the data model and often the workflow. When setting up the project in the software, you should establish the following:

- What units are to be used in the model?
- What is the coordinate system?
- What type of input data is to be used?
- What format will the data be provided in?
- How and where are the data stored?
- What is the objective of the model?
- What is the geological environment? Can you draw it?
- What is the AOI (area of interest)? Does it include an aquifer?
- How many wells are there?
- Are there any spatial or vertical trends recognized in the data?
- Are there any analogues that might be used to guide the modelling?

A data delivery schedule should be established for any additional data or interpretations that may be included in the project. Projects often veer off track when new data are supplied after a milestone has

Reservoir Modelling: A Practical Guide, First Edition. Steve Cannon.

been passed in the workflow. Often it is worthwhile agreeing a cut-off date for any additional data.

The quality of the input data should be reviewed at the start of the project to judge what can be done to improve or replace it. Inconsistencies in the data can cause numerous problems at every step of the modelling process. Some examples of inconsistencies that are unacceptable are as follows:

- Crossing horizons often due to poor depth conversion or well control
- Spikes on an horizon due to poor quality control at the mapping stage
- Multiple deviation surveys available for the same well
- Horizons not tied to the well-picks; multiple sets of horizon picks
- Multiple well correlation schemes
- Poor depth control between core and log data
- Inclusion of erroneous core analysis data leading to poor statistical analysis.

Most companies possess a corporate database for data storage; Openworks™ and Geoframe™ are the most common in use, although there are others such as Oilfield Data Manager (ODM™) that is popular among smaller companies and consultancies as project databases. The management of the corporate database is not a subject for the project team; however, there is a requirement to access the database for input data and often to return completed interpretations or results to the database. It is recommended that one member of the project team is tasked with organization and management of both the project data store and the relationship with the corporate database.

A surprisingly small amount of data is required to build a simple representative model, but to capture the range of uncertainties in a reservoir, more information will often be required than is available. Rarely, there may even be too much data and an over-complicated model can result that ultimately may have little practical value.

The primary data types used for reservoir modelling are as follows:

- *Seismic* derived interpretations and processed volumes
- *Well* data including deviation data, cores, logs and pressures
- *Dynamic* data from well test and production.

One key project input required at the start is the coordinate system; most software tools will have a local coordinate system, where the model has no reference to a geographic location or specific

geographic/projected system based on globally defined projection systems. However, where the key input component is seismic data, a regional coordinate system will be required that uses the navigation data acquired during acquisition.

2.1 Seismic Data

Seismic data generally delivers the inter-well information, either as a two-dimensional interpreted horizon or as a three-dimensional volume. The task of the seismic interpreter is to provide key mappable horizons and faults from which the structural framework of the geological model can be constructed. The horizons and fault input data are interpreted in time and subsequently depth converted using a velocity model. As the interpretation is done in two dimensions, it is recommended to visualize the data in 3D and determine if there are any inconsistencies.

2.1.1 Horizons

Interpreted seismic horizon time data are imported from the database to the project data store. Depth-converted versions of the horizons should also be stored here. The data are generally a series of regularly spaced points having X, Y (location) and either Z (depth) or time values. These points are mapped using conventional deterministic algorithms such as convergent gridding, spline methods or kriging, producing contoured surface maps of the horizon. The mapping can be tied to wells or incorporate fault data as required. Like many processes in reservoir modelling, this is often a matter of trial and error to get the 'best looking' result. Judicious editing is usually required to get a surface usable for modelling.

2.1.2 Fault Sticks and Polygons

Input for fault modelling generally comprises either fault sticks or mapped polygons. Interpreted time fault sticks are the intersection line between a fault plane and a seismic section, whereas a fault *exclusion* polygon is an area on the map where there is a gap in the surface interpretation. Modelling faults from seismic data is a challenging task, not least because of the number of uncertainties: seismic processing, migration velocities and picking of faults from the lower quality data around the discontinuity. Faults are often interpreted in depth-converted volumes to improve the characterization.

2.1.3 Surface Intersection Lines

Surface intersection lines such as erosive sub-crop lines, top-lap or down-lap truncation lineations are interpreted in time and are generally recognized as 'fault boundary' data types.

2.1.4 Seismic Data Volume

The seismic data volume is usually uploaded from a corporate database directly into the modelling project. A number of different seismic volumes may be loaded depending on the different processing results; different products may aid structural interpretation or enhance attribute analysis. The days of a single seismic data set for interpretation are long gone! The volumes can be used for visualization in time or depth and comparison of the interpreted horizons and faults against those included in the geological model.

2.1.5 Velocity Model

The velocity model is generally stored in the project data store either as a function, a grid or as a cube. The data can be loaded into the project if depth conversion is to be carried out as part of the modelling exercise. Alternatively, depth-converted surfaces and fault information are provided.

2.2 Well Data

Well data are generally point source data from a non-regular 'grid' over the area of interest. As such, the data represents a very small investigation volume for the reservoir that is to be modelled, but it is also the 'hardest' data available to the project team. Consistency in all aspects of these data is crucial, especially in projects where there may be many wells to include; consistent well names and basic datum information should be checked thoroughly before loading. Different databases have different ways of storing and exporting this fundamental data and an experienced operator should be involved in extracting the data efficiently.

2.2.1 Wellbore Path

A single quality-controlled collection of the current valid survey data set should be available. Uniqueness of well path data is essential. If

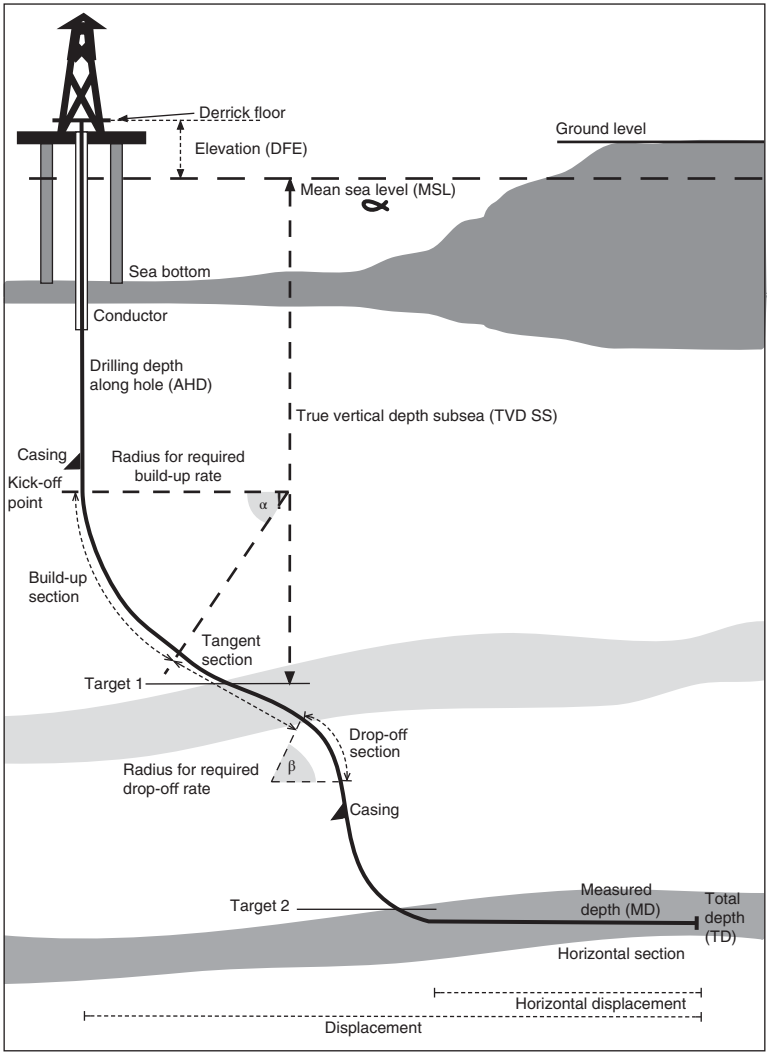


Figure 2.1 Depth measurement and well path trajectory terminology. *Source:* Cannon (2016). Copyright 2016, John Wiley & Sons.

editing of the data is necessary, old versions should be removed or flagged, thus avoiding later erroneous use (Figure 2.1).

Wellbore path data are computed from suitable corrected direction survey data and are stored in the database. Wellbore path data should

consist of (*x, y, z*) locations and a surface location. Alternatively, a wellbore survey may be provided as measured depth (MD), azimuth and angle from the vertical. The data should be regularly sampled along the well bore (i.e. regularly sampled in MD) with an interval of less than 1 m (usually 0.15 m). The calculation method to correct the MD to true vertical depth (TVD) should also be established; either minimum curvature or cubic spline method.

The method used will have an impact on how well the log data matches the trajectory survey: cubic spline method is referenced to TVD resulting in uncertainty when MD is calculated. Minimum curvature is the reverse and may give uncertainty in the TVD calculation. If log data and trajectory data use different calculation methods, then the degree of error will increase with the length of the well. Depth uncertainty in modelling is one of the commonest problems associated with tying surfaces to wells.

2.2.1.1 Composite Log

It is important to ensure that a complete set of quality-controlled composite data is available for spatial modelling and property analyses. Table 2.1 gives a listing of curves and specific log names that should be defined in the modelling database. Logs should be pre-processed for modelling purposes and a set of curves assembled either in the project data store or in a separate petrophysical database. These data will form the 'basic input data' for reservoir modelling.

Some, or all, of the following processing may be advantageous:

- All logs should be resampled to a common regular sample interval.
- For multi-well analysis, environmental correction and normalization of logs may be beneficial.
- Bad data, such as sonic log spikes or washed-out intervals, should be excluded.
- Removal of shoulder effects (buffering) with a masking method can be a useful precursor to blocking of well data.

2.2.2 Computer-Processed Interpretation (CPI) Logs

The primary source for reservoir property data is the petrophysical interpretation of porosity and water saturation; Table 2.2 gives a listing of computer-processed interpretation (CPI) curves that should be available in the modelling database, together with naming conventions. Many of the curves may not be available in any current corporate database and will need to be created and stored in the

Table 2.1 Listing of curves and specific log names that should be defined in the modelling database.

LIS mnemonic	Description	Measurement unit
ACCP	Compressional sonic log	Delta *T*, microseconds/ft
ACSH	Shear sonic log	Delta *T*, microseconds/ft
ACST	Stoneley wave	Delta *T*, microseconds/ft
BS	Drill bit diameter	inches
CALI	Calliper; borehole diameter	inches
CMFF	Free fluid index from CMR	
CMR3	Nuclear magnetic resonance	Relaxation time, seconds
DEN	Bulk density (RhoB)	g/cc
DENC	Bulk density correction	g/cc
FTEM	Formation temperature	degrees C or degrees F
GR	Natural gamma ray	API
GRKT	Potassium:thorium ratio	
K	Permeability	mD
KTIM	Permeability using Timur	mD
NEU	Neutron porosity	Hydrogen index/pu
PEF	Photoelectric absorption effect	Barnes/electron
RDEP	Deep resistivity	Ohms/m
RMED	Medium resistivity	Ohms/m
RMIC	Micro-resistivity	Ohms/m
RSHA	Shallow resistivity	Ohms/m
RT	Formation (true) resistivity	Ohms/m
RXO	Invaded zone resistivity	Ohms/m
NGS	Spectral gamma ray	API
SP	Spontaneous (self) potential	Direct current mV
TCMR	Relaxation time from CMR	Seconds
TEN	Tool tension	Pounds
TH	Thorium from SGR	p/p
U	Uranium SGR	p/p

project data store if required. All curves must be available in a regular re-sampled form.

The reservoir modeller should also find out how the different interpreted logs were generated; the main logs required for populating a reservoir model are a facies log, a porosity log, a permeability log

Table 2.2 List of major logs used for a CPI and available for the modelling database.

CPI	Description	Unit/Boolean
BADHOLE	Over gauge hole	Flag
CALCITE	Calcite	Flag
COAL	Coal	Flag
EFAC	Electrofacies	Flag
LIMESTONE	Limestone	Flag
PAY	Pay flag	Flag
PERM	Permeability	mD
PERM_NET	Net permeability	mD
POR_EFF	Effective porosity	v/v
POR_EFF_NET	Net effective porosity	v/v
POR_TOT	Total porosity	v/v
RESERVOIR	Reservoir flag	Flag
SAND	Sand	Flag
SW_EFF	Effective water saturation	v/v
SW_EFF_NET	Net effective water saturation	v/v
SW_IRR_EFF	Effective irreducible SW	v/v
SW_IRR_TOT	Total irreducible SW	v/v
SW_TOT	Total water saturation	v/v
SWE_MOD	Modified effective SW	v/v
SWT_MOD	Modified total SW	v/v
SXO_EFF	Effective SW in invaded zone	v/v
SXO_TOT	Total SW in invaded zone	v/v
TAR	TAR – dead oil	Flag
VCALCITE	Volume of calcite	v/v
VCBW	Volume of clay bound water	v/v
VCLAY	Volume of clay (diagenetic)	v/v
VCOAL	Volume of coal	v/v
VDOLO	Volume of dolomite	v/v
VHALITE	Volume of halite	v/v
VLIME	Volume of limestone	v/v
VSAND	Volume of sand (quartz)	v/v
VSHALE	Volume of shale	v/v
VSILT	Volume of silt	v/v
VWAT_EFF	Volume of movable water	v/v
VWAT_TOT	Volume of total water	v/v
VXOWAT	Volume of water in invaded zone	v/v

and a water saturation log. In addition, some understanding of the uncertainty associated with each of the interpretations should also be ascertained. The team petrophysicist should be able to provide the answers; however, if working with legacy data, this may not always be possible.

2.2.3 Core Descriptions

Core descriptions are used for geological analysis, and the following types should be available for review:

- Detailed 1:50 sedimentological core description.
- High-resolution structural core description usually at a scale of 1:40 for use in fracture modelling.
- Log-calibrated 1:200 generalized description to tie core and log petrophysical properties such as porosity and permeability.

It is important to shift the description to loggers' depth to achieve correspondence between the core description MD and the petrophysical logs. Be on the lookout for incomplete core recovery and misplaced sections. Standard mnemonics used for core results are listed in Table 2.3.

2.2.4 Core Photographs

Core photographs should be shifted to logger's depth along with the core itself. Core photographs become the permanent data record as the core material may be accessed repeatedly and often disturbed through handling. It is wise to make core/log shift curves and store these in the relevant database. These can then be used with all the core-based data in a consistent fashion.

2.2.5 Core Plug Data

A unique set of measurement results from core plug data (routine core analysis) should be assembled in the appropriate database for reservoir modelling. For data to be considered 'final', it should be overburden corrected (porosity and permeability) and permeability corrected for gas slippage, the Klinkenberg correction.

The plug number is useful for comparison with core photographs.

Uncorrected measurements should not be stored in the reservoir modelling dataset, as this can be a source of confusion. Data should first be shifted according to a master composite log and an overburden correction of data is necessary.

Table 2.3 A list of the standard mnemonics used for core analysis data.

Core plugs	Description	Measurement unit
CORENUMBER	Sequential core number	
CPOR	Helium porosity	% or fraction
CPORF	Fluid-filled porosity	% or fraction
CPOROB	Overburden-corrected porosity	% or fraction
CPORV	Pore volume	v/v
CPORVOB	Overburden-corrected pore volume	v/v
CSG	Gas saturation	% or fraction of PV
CSO	Oil saturation	% or fraction of PV
CSW	Water saturation	% or fraction of PV
GRDEN	Grain density	g/cc
KHKL	Klinkenberg-corrected horizontal permeability	mD
KHL	Horizontal liquid perm	mD
KHLOB	OB-corrected liquid horizontal permeability	mD
KHOB	OB-corrected horizontal permeability	mD
KHOR	Horizontal permeability	mD
KVER	Vertical permeability	mD
KVKL	Klinkenberg-corrected vertical permeability	mD
KVL	Vertical liquid perm	mD
KVLOB	OB-corrected vertical liquid permeability	mD
KVOB	OB-corrected vertical permeability	mD

Core measurements, unlike log measurements, are not sampled at regular increments; therefore, they should be considered as discrete rather than continuous data to avoid interpolation between points during data import. For use in data analysis and subsequent property modelling, core plug measurements must have been shifted to the closest depth increment in the corresponding CPI and/or composite data.

2.2.6 Reservoir Zonation

There are likely to be a number of different reservoir zonations stored in company archives often generated by different disciplines, for example the geologist's sequence stratigraphic approach compared with the petrophysicist's flow zonation. A guiding principle should be to integrate the coarsest scale of zonation, usually the seismic interpretation with a sequence stratigraphic breakdown of intervening field-wide horizons; any debateable correlations should be excluded until their significance is understood. Other zonations can be stored in the project database, but these should be clearly defined as to origin and specific use; for instance, a flow-based zonation may be compared with a geological one to determine areas of commonality.

2.2.7 Pressure Data

Pressure data should be stored in the database. The data are often incomplete and will need to be carefully reviewed for validity. It is always important to consider the results within their stratigraphic context especially when comparing data from different wells; are observed pressure differences explainable by local barriers for instance or is there an indication of reservoir compartmentalization due to faulting? All pressures must be recorded in consistent units, either bar per metre (b/m_a or b/m_g) or pounds per square inch (psi_a or psi_g), where '*a*' stands for atmospheric and '*g*' stands for gauge. This simple datum variation of 14.7 psi has been the cause of numerous mistakes in the integration of data.

2.3 Dynamic Data

2.3.1 Fluid Data

Oil and gas fluid data are required to evaluate the properties of produced fluids at reservoir conditions, in production tubing, in process facilities and in pipeline transportation. The key PVT (pressure–volume–temperature) properties to be determined for a reservoir fluid include the following:

- Original reservoir fluid composition(s).
- Saturation pressure at reservoir temperature.
- Oil and gas densities.
- Oil and gas viscosities.

- Gas solubility in reservoir oil (GOR, R_s).
- Liquid content of a reservoir gas.
- Shrinkage (volume) factors (B_o, B_g, B_w) of oil, gas and water from reservoir to surface conditions.
- Compositional variation with depth.
- Equilibrium phase compositions.

Reservoir fluid volumes are generally reported in stock-tank volumes, and the shrinkage factor is therefore a critical property. It should be noted that this property is related to the actual process by which the reservoir fluid is established. Usually, shrinkage factors are calculated by equation-of-state (EOS) simulations. Experimental data are used indirectly to tune the EOS parameters.

2.3.2 Well Test Data

Well test data can be used to determine effective permeability and is divided into the following types:

- *Transient well test (DST) raw data:* Rates and pressures.
- *Transient well tests:* Perforation intervals and main interpretation data.
- *Transient well test interpretations:* Permeability thickness, skin, boundaries.
- *Production log (PLT) interpretations:* Oil, gas and water rates in the well, plus pressure distribution.

2.4 Important Specialist Data

2.4.1 Special Seismic Cubes and Seismic Test Lines

These could include coherence, inverted, 4D and pre-stack depth-migrated cubes. These cubes should be stored in the project database alongside the standard reflection seismic data for easy visualization and interpretation.

2.4.2 SCAL Data

Special core analysis (SCAL) data should be regularly collected for defining petrophysical interpretation parameters and for

dynamic measurements. Routinely collected data include the Archie parameters *a*, *m* and *n*, cation exchange capacity (CEC), capillary pressure, wettability and relative permeability. These values are all collected and used in the petrophysical assessment of the reservoir and later in dynamic modelling. If using advanced 3D saturation modelling tools in the static model, such as *Geo2Flow*™, these data will also be required.

2.4.3 Borehole Image Logs and Interpretations

Due to their size, raw and processed borehole image data are not generally available online and are stored on tape or CD as part of a service company report. Ideally, the interpretations (depth, dip, dip azimuth, dip type) should be stored in the project database.

2.5 Conceptual Models

Having collected and evaluated the available data, the specialists in the team must develop the conceptual models of the field so that the modeller has an idea of what the field model should look like; no software product will build a meaningful model without the addition of this element of hard or deterministic data. There are a number of conceptual models that can influence the end product: the structural model, the stratigraphic model, the depositional model, the property model and the 'plumbing' model.

Seismic data are often interpreted with a gross structural model in mind; in extensional basins, you expect to see normal faults creating horst and graben features; a compressional setting might result in rollover anticlines or reverse faulting; salt or mud diapirism can create pillars and walls with sediments deposited in between. These specific features should be captured in the reservoir model and a comparison should be made between the seismic structural interpretation and the fault model; bear in mind that structures apparent in time can vanish in depth after conversion due to the velocity model.

Seismic interpretation can also deliver the large-scale horizon correlation that forms the basis of the stratigraphic model; however, internal stratigraphy comes from well correlation. The degree and type of geological correlation can lead to over-determined models, layer-cake constructions, where the geostatistical component of the model becomes a simple averaging of data rather than stochastic

distribution. The types of correlation schemes available to model are many and choosing the one that best represents the geology and captures the impact on fluid flow is a challenge that we will discuss more fully later.

The key conceptual model is the gross depositional environment and the environment of deposition recorded in the field. The interpretation of cores, logs and seismic might lead to the interpretation of a terrestrial, marginal marine or deepwater environment of deposition but what does the subject reservoir represent within that setting. Aeolian, alluvial, fluvio-deltaic, shallow marine and deep marine environments represent common clastic reservoirs; carbonate reservoir are typically platforms, ramps and reefs. Each can be modelled using the many methods available in the software toolbox, but a common theme will be to capture what flows and what does not flow in the reservoir, leading to discussion of flow units and rock types: another topic that deserves greater discussion later. It is from the gross depositional model that the elements of the facies model will be applied to the well data and calibrated to the wireline logs.

The property model may be affected by trends in the data that need to be identified before geostatistical modelling can begin, remember stationarity and normal distribution. The commonest trend observed in porosity data for instance is a reduction with increasing depth; this is due to compaction or diagenesis. Differences in porosity and permeability between the hydrocarbon leg and the aquifer are common, and when observed need to be handled by data partitioning before further geostatistical modelling can be performed; in other words, do not combine the two sets of data together to get an average, treat them separately.

Finally, the 'plumbing model', a term I came across recently in a Shell affiliate company. This model tries to capture the flow in a model in diagrammatic form especially where permeability contrasts between different reservoir units have an impact on the drive mechanism; this is especially true with an active aquifer or where coning might be expected in horizontal wells.

2.6 Summary

Before you start on a project, make sure you ask all the right questions: is there a conceptual model; can you draw the depositional environment; what are the unknowns; what assumptions have been made; is

there sufficient data; are there ongoing studies that might influence the outcome; is there a bias in the data due to well location; is the required objective achievable in the time available?

When you review all of the input data required for reservoir modelling, it becomes apparent that the modeller has to be a multi-skilled geoscientist who can understand the challenges facing seismic interpreter, the reservoir geologist, stratigrapher, petrophysicist and reservoir engineer. It is more about realizing the uncertainties in the interpretation of these data than just accepting the inputs; a single interpretation of the data gives a single deterministic best-case scenario, valid for only one view of the reservoir. We undertake 3D reservoir modelling to test these uncertainties using stochastic methods.

3

Structural Model

Building the structural model is the first step in the modelling workflow and probably the most crucial in terms of representing the large-scale geology of a field. At the most basic level, all that is required is a top reservoir structure map and the interpreted faults; a base surface may also be incorporated. The objective is to construct a consistent reservoir framework that can be gridded for 3D geological or dynamic simulation. The framework should capture the large-scale heterogeneities affecting flow in the reservoir, such as faults or unconformities. The reservoir framework also comprises the input from the interpretation of well and seismic data: gross stratigraphic correlations, mappable horizons, resolvable faults and an increasing number of 3D attributes such as coherency data and surface dip and azimuth information. The geophysicist should always be encouraged to identify all resolvable faults, fractures and linear discontinuities; they may become important later in the field life. Together with the geologist, modeller and reservoir engineer, the team should make the final decision regarding what to model.

3.1 Seismic Interpretation

Structural analysis is largely based on the interpretation of 2D and 3D seismic interpretation: it is not my intention to describe the process of seismic interpretation, but it is necessary to discuss the assumptions and uncertainties made by the interpreter. I recommend the volume '3-D Seismic Interpretation' as an excellent discussion of all the aspects of the topic (Bacon *et al*., 2003). The seismic interpreter is looking for potential hydrocarbon traps in the data; these may be structural or stratigraphic (Figure 3.1) and may exhibit a direct

Reservoir Modelling: A Practical Guide, First Edition. Steve Cannon.

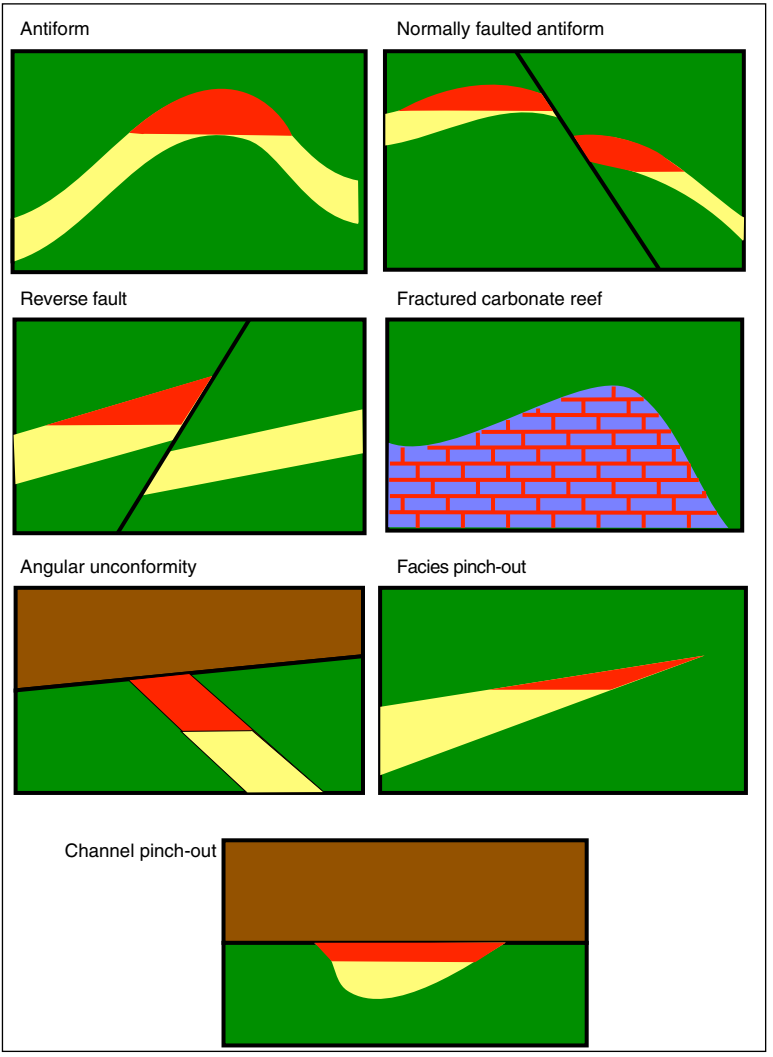


Figure 3.1 Examples of simple structural and stratigraphic trapping mechanisms that can be reproduced in 3D geocellular models.

hydrocarbon indicator (DHI). The quality and extent of the data set will determine what can be achieved; to expect a high-resolution interpretation from a bunch of 2D lines is unreasonable. Often a gross regional understanding of the structure will drive the structural

interpretation; in an extensional regime, normal faulting is expected, but later re-activation of faults can result in uplift of individual fault blocks. Compressional regimes can produce thrusting and slumping of sediments. It is important to determine whether a particular structural concept has been applied during the interpretation, as the resulting structural model should reflect this.

Seismic data are measured in two-way travel time; the time it takes for an acoustic wave to travel to a reflector and return to the receiver. A seismic reflection is a measure of the contrast in elasticity between two different rocks, also known as the reflection coefficient. The reflection coefficient can be estimated from the velocity (Vp) and bulk density (ρ_b) of the rocks using values from the sonic and density logs, respectively (Figure 3.2). The contrast will be greatest between a well-cemented sandstone or limestone and a soft shale: the contrast between a shale seal and sandstone reservoir may not be an obvious booming event, especially where there is a gradational boundary; in other words, picking top reservoir is not easy! It is therefore important to ask the interpreter their opinion on data quality and resolution, especially around the flanks of the structure and interpreted faults. As a rule of thumb, the vertical resolution of seismic data is between 25 and 50 m depending on the depth of interest and the overburden being investigated. Picking a fault on seismic is subject to an error of 100–200 m laterally across a surface; this could be the same as the lateral cell dimension in the geo-model. The quality of seismic data and the area over which an interpretation is required for reservoir modelling purposes should be specified in the project work scope.

A seismic horizon is defined as a set of free points/lines in time that are effectively continuous over large parts of the area of interest (AOI). Note that only the interpreted free points from the time domain are depth converted, and these free points are often re-gridded in the depth domain. The horizons should be interpreted consistently based on well-tie analysis and in some cases seismic modelling. All interpretations should be made on the same in-line/cross-line interval. Interpret only where the horizons are defined and not in highly uncertain areas. Areas of interpretation uncertainty should be separated from other areas by using separate seismic grids (or surfaces).

Time stratifications are sparse, and discontinuous time interpretations, such as seismic facies, may be related to depositional packages, for example, clinoforms. Where present, these interpretations are valuable information used in the conceptual geological model (Figure 3.3). Time polygons can be created as closed boundaries

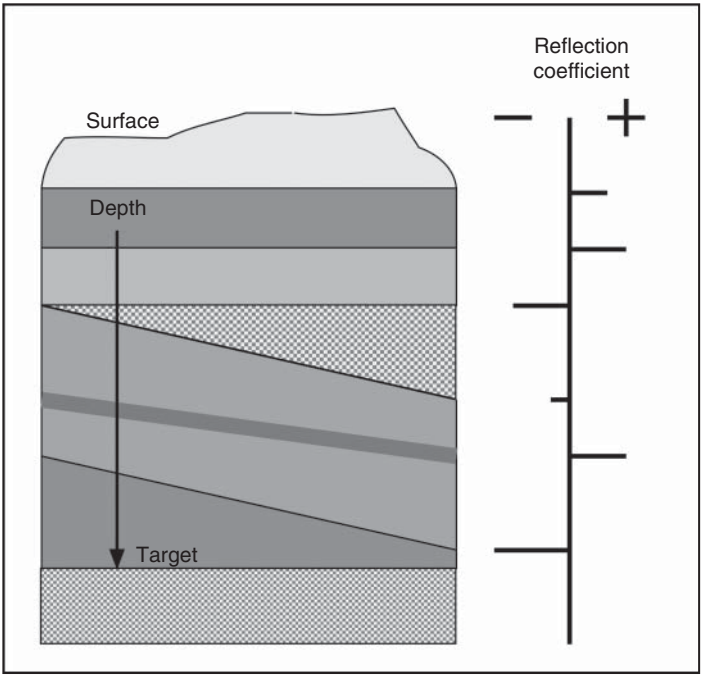


Figure 3.2 Representation of the seismic response at lithological interfaces producing a reflection coefficient that may be used to generate a synthetic seismic seismogram used in depth conversion. *Source:* Cannon (2016). Copyright 2016, John Wiley & Sons.

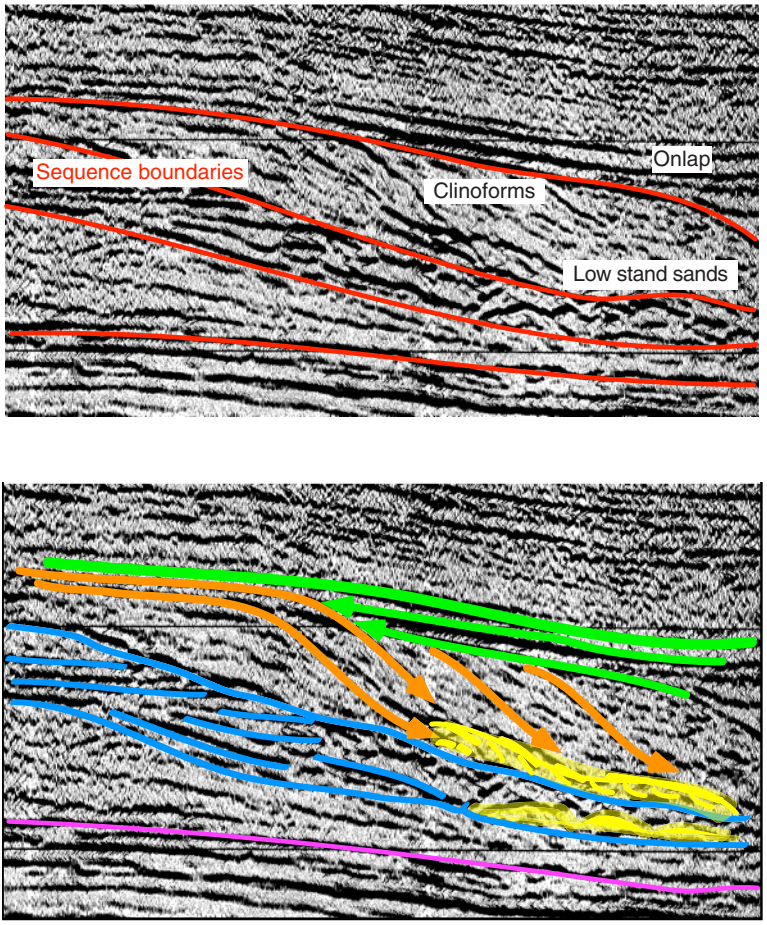


Figure 3.3 Example of sequence stratigraphy used in the interpretation of large seismic features typical of a lowstand to highstand cycle.

describing erosion areas, AOI for simulation, migration paths and any lateral information that could enhance the quality of the geological modelling.

2D or 3D time attribute maps may show geological features (e.g. surface dip often picks up faults with offsets close to seismic resolution) and, if so, should be a product of the seismic interpretation. An investigation of the different attributes within the reservoir area should be performed to ensure that any possible connection between geology

and seismic response will be detected and, if possible, be implemented in the geological modelling.

There are a number of uncertainties in seismic interpretation, and while this is often a function of data quality, it may also be due to interpretation error. Maps defining uncertainty in the interpretations may be created to define residual maps. If the map value is 5 ms, this implies 95% probability for that the interpreted reflector is 5 ms from the equivalent synthetic reflector that would have been mapped. The main sources of seismic uncertainty are as follows:

- *Seismic well tie* – The reflection recorded on the seismic section may not tie the same event in a well; poor seismic resolution can result in 10–20 m mismatch. When checking the difference between a depth-converted surface and the corresponding well top, approximately 5 m is acceptable, but more than 10 m indicates a more serious problem.
- *Seismic pick* – The reflector that is being traced may lose coherency or continuity introducing another uncertainty. Interpreters often say that they could follow a reflector up or down and after depth conversion may need to make a correction to the interpretation.
- *Imaging* – The seismic response weakens with depth or below high-velocity layers as the acoustic energy is depleted, resulting in poorer amplitude response and lower resolution; around faults, the acoustic waves are dissipated leading to further deterioration of the image.
- *Depth conversion* – In many ways, this process leads to greatest systematic uncertainty in seismic interpretation. For the purposes of structural modelling, we will focus on this process and the uncertainties.

The experienced interpreter will appreciate that these challenges exist and that a 'zone of uncertainty' exists around an interpreted horizon. This can be described as 'measurement' uncertainty as opposed to purely interpretation uncertainty. Thus, a description of the variability or tolerance can be quantified for future uncertainty workflows.

3.1.1 Depth Conversion

Velocity analysis is a very important part of the process leading to the seismic framework. The analysis involves finding velocity trends and velocity functions that yield a proper velocity model for depth

conversion. It is important to look at the data and explore every possible relationship to obtain the best model for depth conversion; a robust velocity model makes it possible to depth convert the seismic cube correctly and to do the structural interpretation in the depth domain.

There are two main sources of velocity information: well data and seismic imaging. From well data, we are measuring the elastic properties of a point (V_{iint} – instantaneous interval velocity), a particular depth interval (V_{int} – average interval velocity) or a layer average (V_{ave} – ratio of the depth to the vertical one-way time). We get the instantaneous velocity data from the sonic log and the layer average data from vertical seismic profiles (VSP). Velocity data from seismic imaging is a function of indirect measurements made during seismic data processing or optimization, such as normal move-out (V_{nmo}), root mean square (V_{rms}) or migration data (V_{mig}).

Instantaneous velocity

$$V_{\text{inst}} = \frac{d_z}{d_t}$$

Interval velocity

$$V_t = \frac{Z_m - Z_n}{t_m - t_n}$$

Average velocity

$$V_{\text{ave}} = \frac{\sum_{i=1}^{n} z_i}{\sum_{i=1}^{n} t_i} = \frac{\sum_{i=1}^{n} v_i \Delta t_i}{\sum_{i=1}^{n} t_i}$$

RMS velocity

$$V_{\text{rms}}^2 = \frac{\sum_{i=1}^{n} v_i^2 \Delta t_i}{\sum_{i=1}^{n} t_i}$$

The analysis should be done in parallel with the seismic interpretation to gain a better understanding of how the time–depth relationship varies across the field. The outputs of the velocity analysis procedure include the following:

- Velocity model – functions, time and depth maps for each layer, or a cube.
- Miss-tie points at each well location yielding uncertainty velocity maps and depth uncertainty estimates for each layer.

Surfaces in the overburden are needed to increase the quality of the velocity model and can be interpreted on a coarser grid sufficient to support the velocity model. The velocity model will require at least one layer above the top reservoir layer and may have fewer layers within the model than the reservoir model. As the velocity is designed to capture the boundaries that impact on the time–depth relationship, it will differ from the geological model (Figure 3.4).

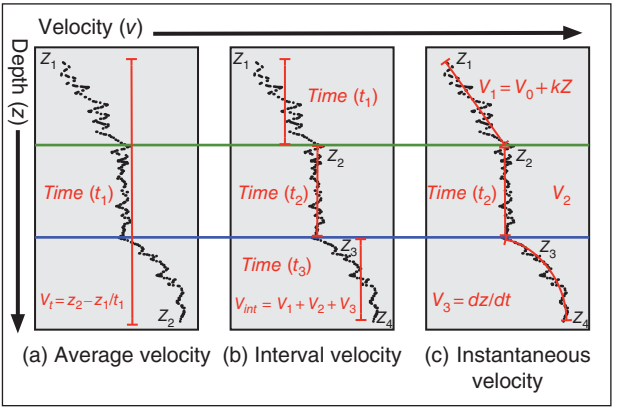


Figure 3.4 Examples of different velocity functions used for depth conversion showing the impact of additional data on the type of function applied; calibrated checkshot and VSP data are required for the detailed analysis of the overburden. *Source:* Reproduced with permission of Schlumberger-NExT.

Depth conversion is a straightforward process once the velocity model has been defined. The process transfers the interpreted free point data (horizons, fault sticks and volumes) from the time domain to the depth domain.

The results of the process should be stored in the project database and are essentially threefold:

- Interpreted horizons (free points) in depth.
- Fault sticks (free points) in depth.
- Seismic cube in depth (optional).

The first two items are the basis for the reservoir framework. The results will often need to be flexed to fit the well data; the degree of flexing should not exceed the uncertainty inherent in the velocity model. Make sure that only the interpreted points are depth converted; do not include interpolated or gridded points! Quality control the depth-converted grids/faults in the export process. For

new points, ensure that the converted depths estimated fall within the uncertainty range obtained from the velocity analysis.

3.1.2 Interpretation in Time Versus Depth

Interpreting horizons and fault sticks is usually done in the time domain, but if there is a good velocity model for the AOI, much of the interpretation can be carried out on depth-converted seismic cubes.

The advantage of a depth approach is that the interpretation can be performed in seismically poor regions with a regard to what is acceptable geologically, generating a more sensible interpretation. In the time domain, the interpreter must consider the effects of wave propagation through the overburden and influence on a consistent interpretation. Tying into well markers is also easier when working in the depth domain, and interpretation around faults is often easier. Geology is consistent in real space, and it is much simpler to extrapolate the interpretation in poor signal regions in the depth domain. Seismic sections can also be put as a backdrop on the well correlation displays as an aid to correlation and possibly to make interpretations more realistic.

The drawback of moving to depth too quickly is that the interpretation has to be redone when new information (wells) changes the velocity model on a semi-regional scale. In essence, the move to depth is a function of how well the velocity model performs, which is often a function of the maturity of the area or field.

3.2 Fault Modelling

We build reservoir models with non-vertical faults to improve the volumetric estimate and to better understand the distribution of hydrocarbons in the field. The process can also be used to introduce separate compartments into the model, thus honouring pressure variations across the field. A fault model also aids in understanding reservoir connectivity in different parts of the field improving the stratigraphic model and the understanding of trapping potential.

Fault modelling is the process of mapping faults in 3D within the reservoir. It is a process of identifying discontinuities directly from the fault trace on some depth horizon, or fault information that may already have been provided by the geophysicist, for example, fault sticks or depth midlines. The fault model can be constructed in time

and depth converted, or in depth. Retaining a time model makes quality control, by matching sections to seismic, easier. The fault modelling workflow is a simple five-step process that can be carried out in depth or time.

1. *Preparation and assigning the input data to the faults.*
   Fault modelling is performed using a variety of fault input data types. The input data must be assigned to the fault(s) to which it refers.
2. *Generate the fault network.*
   The network can be seen as a rough guide telling the software the main fault geometries and where the different faults truncate each other. In the network, Hanging Wall and Foot Wall are defined for the faults (Figure 3.5). The fault network can be automatically generated or created by the user (digitized).
3. *Generate fault surfaces.*
   The fault surfaces can be gridded using any data source that describes the position of the fault planes in space. Some common data types used include the following:
   - Depth midlines
   - Fault sticks
   - Fault surfaces
   - Fault line and/or polygon data
4. *Generate horizon lines.*
   The horizon lines are the intersection between the fault surface and the associated horizons; the lines define the location of the fault in the 3D grid and the throw of the fault. These lines are manually/automatically generated by resampling the intersection using an influence distance and an extrapolation distance (Figure 3.6). Truncations and connections are created automatically, as they are defined in the network.
5. *Adjust horizons to the faults.*
   The final step in the fault-modelling process is to ensure that the horizons match the fault model. This is done by re-gridding an area of the surfaces around each fault.

The major reservoir-modelling software products have different methods for structural modelling, but generally, they all require the same input of faults and surfaces. Common methods include building a simple grid, a corner point grid using fault pillars and volume-based modelling, where a fault model is built directly from the seismic interpretation of the structural framework. Before proceeding, ensure

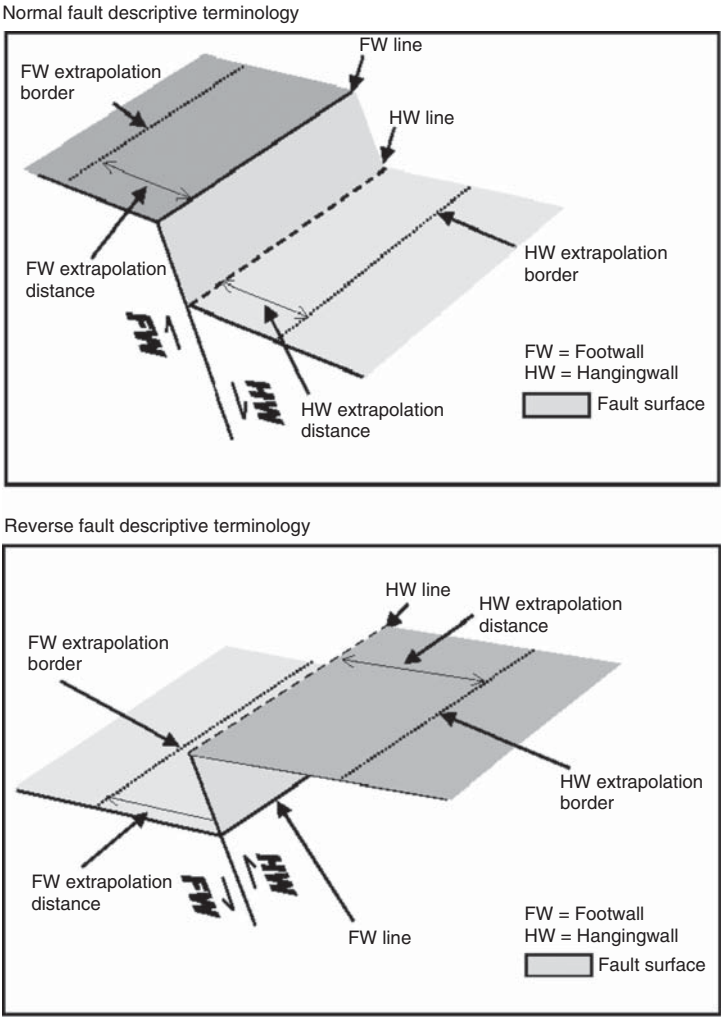


Figure 3.5 Common descriptive terminology for normal and reverse faults: the extrapolation distance is the interval the software interpolates in building a robust fault. *Source:* Reproduced with permission of Emerson-Roxar.

that the input data, faults and surfaces are as consistent as possible because it is much more difficult to edit the structure in 3D than in 2D.

The ever-improving quality of seismic acquisition-processing methods means that seismic interpreters can delineate more and more detailed faulting over a field. It makes little sense to the reservoir

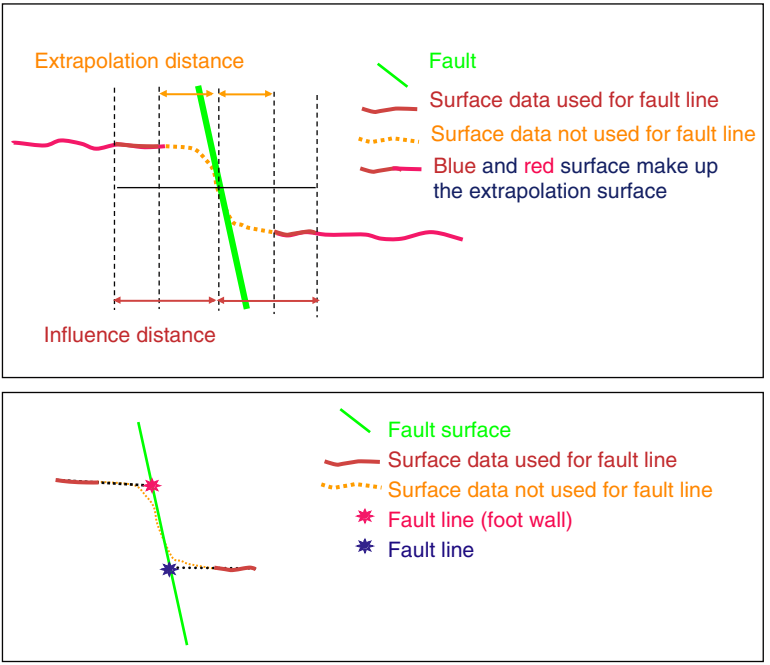


Figure 3.6 Modelling terminology used for the creation of horizon lines and surfaces. *Source:* Reproduced with permission of Emerson-Roxar.

modeller to capture all of these faults especially as the dynamic model will probably not be able to replicate this detail. Therefore, a hierarchy of fault importance should be established while building the geological model so that a realistic set of faults are represented; these faults should be seen to have an impact on the hydrodynamics of the field or the volumetrics. The following criteria could be applied in choosing which faults to model:

- Bounding faults that delimit the reservoir.
- Faults that divide the reservoir into separate compartments.
- Faults that intersect wells and are therefore considered hard data.
- Other seismically resolvable faults that might impact fluid flow.
- Other definable faults might be handled as transmissibility barriers.
- Fractures that are recognized in core or logs might be represented as stochastic permeability modifiers.

A detailed structural analysis of the field area should also be carried out at this stage to define the types of fault present and

their relationships, especially if some gross conceptual structural interpretation is preferred.

3.2.1 Fault Interpretation Process

- Fault planes must be interpreted over the same intervals as the horizon interpretations. The planes should only be interpreted to their vertical extension (i.e. no ghost interpretation) and this should be done over the entire fault length. Where faults intersect, the interpretation should go beyond the fault intersection to ensure well-defined truncation lines.
- Each fault should be named separately and must be traceable throughout the whole modelling process. Suggested rules for fault naming are given later.
- Fault cut-off lines are used for areas near faults that are difficult to interpret; in complex faulted areas, it may be advisable to interpret fault horizon cut-off lines directly from the seismic data, that is, where the seismic quality is reduced. This can be achieved by linking fault/horizon contact points along fault strike to produce a polygon.
- Fault midlines should be interpreted to define faults close to seismic resolution that are picked up by attribute maps or coherence data but are not clear enough to be independently interpreted. Midlines should be interpreted for all horizons. A suitable throw distribution can be added to the fault midlines later in the modelling process.

3.2.2 Fault Naming

As part of the fault interpretation, faults should be given names that can be used in the rest of the modelling process. Bear in mind that some software products have limitations on the number of letters/numbers that may be used.

An example of possible fault naming convention is given in the Table 3.1. When gridding faults that bifurcate, a fault MF2 could be further split into various parts: MF2A, MF2B, etc. If possible, a time aspect should be considered when splitting, so the older fault is divided, whereas the younger fault is kept unchanged.

It is recommended that a structural geology QC loop is run using fault plane projections to ensure geologically reasonable fault linkages and horizon fault cut-off line geometries. The faults should be tested for consistency with respect to fault/fault and fault/horizons intersections (Figure 3.7). Once these checks have been made, a fault network model can be devised. The network should initially include only those

Table 3.1 Example of fault classification and naming procedure.

Fault type	Fault name	Throw
Major faults	MF1–MF99	>50 ms TWT
Minor faults	F100-F299	10–50 ms TWT
Near-resolution faults	NRF300-SSF699	<10 ms TWT

faults that compartmentalize the field; other faults can be added later. By starting with the major faults, an initial grid can be generated to estimate gross rock volume and to test the basic structural concepts.

Having quality-controlled the faults and built a model or network, it is time to integrate them with the depth-converted interpreted seismic horizons. Ringrose and Bentley (2015) suggested that the horizons should be imported in the modelling software as points to better QC the inputs. Specifically look for points that have been dragged down on a fault surface or areas where the horizon interpretation is less robust. It is often easier to see these artefacts of interpretation in the raw state rather than when they have been mapped and smoothed. The next step is to grid the surfaces against the fault network; start with the key interpreted surfaces. Be prepared to do this several times, especially if you are trying to model all the faults at the same time; to begin with, try only modelling the major faults and introduce minor faults one at a time. Bear in mind that every fault will have an impact on the grid quality and integrity, so be prepared to leave out faults that have little impact on flow or are too small to be properly represented in the upscaled simulation grid.

The fault network defines the relationship between faults, their orientation, shape, and sense and magnitude of throw. Major throws will define grid segments, whereas minor throws may displace horizons within segments. Within the grid system mapped fault polygons are represented as pillars of varying thickness equivalent to throw along a surface. The final model will require a boundary polygon to confine the grid structure, based on the input data or the AOI of the model. The grid boundary should also reflect either a dominant fault orientation or flow direction in the reservoir to improve numerical processing. The grid may also be oriented with proposed well direction if a series of horizontal wells are to be used to develop a reservoir; a common option in unconventional field developments. At this time, I would also recommend using a rectangular grid design

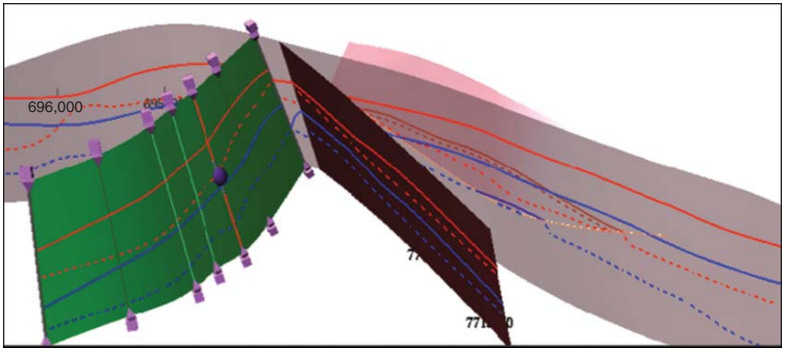


Figure 3.7 Examples of horizon lines, fault surfaces and fault pillars used to edit simple and complex faulted structures. *Source:* Reproduced with permission of Emerson-Roxar.

rather than an irregular grid; once again, this is thinking ahead to the dynamic model and numerical convergence. A regular grid is also easier to upscale and rotate if required.

3.3 Horizon Modelling

Horizon modelling leads directly on to the stratigraphic modelling part of the workflow discussed in Chapter 4. Initially, we are trying to ensure consistency of the grid with respect to cell quality. Horizons in a reservoir model are used to capture the large-scale geological relationship represented by the seismic interpretation; they can represent the base of a sequence, an erosional event or a discontinuous surface. In each case, there will be a series of truncation rules that control the relationship between one surface and another (see Figure 4.1). The simplest relationship is a conformable one; this will ensure that cells in the subsequent grid are not misshaped.

Visually check the interplay between the newly mapped surfaces and the faults; visualizing the intersection of horizon lines with fault surfaces and then editing them is time consuming but can be quite therapeutic! A common process to improve the fault–horizon relationship is to adjust the 'extrapolation distance' between the fault and the horizon. Varying the extrapolation on each side of the fault allows the modelling algorithm to extend the area around the fault that is influenced by the structural dip of the surface (Figure 3.8). Where surfaces are seen to rapidly vary in thickness against the fault often indicates that the surface gridding needs to be repeated with different settings for smoothness. The whole purpose of the workflow is ultimately to generate a 3D grid comprising orthogonal cells.

3.4 Quality Control

Prior, during and after building a fault model, the following checks are recommended:

- Make sure that you assign your data to the right faults by visual inspection.

- Make sure that your fault grouping is correct.
- Make sure that the network is following the input data.
- Check that the truncations are well defined.
- The fault symbols must show that the faults are defined as normal, reverse or undefined.
- Check that the faults are dipping in the right direction according to your geological model.
- If you have Y-faults or listric fault, your network must define these geometries.
- Check that your fault surfaces are honouring your input data, by displaying your input data and your new fault surfaces at the same time.
- Check that the truncations you defined in your network are present in the fault lines.
- Check that you do not have any abrupt changes in fault throw by looking at the fault surfaces colour contoured by the throw.
- Check visually that the fault/horizon lines do not cross each other.
- Check that normal fault/horizon lines have solid lines for the footwall lines and dotted lines for the hanging wall lines.
- Check that the faults you defined as reverse really are modelled as reverse.

3.5 Structural Uncertainty

Uncertainty in the structural model comes entirely from the seismic interpretation and subsequent depth conversion: horizon picking, the well-tie and velocity model introduce errors into the reservoir framework. The impact of a poor time-to-depth model can introduce large errors into the gross rock volume estimate, up to 30% in my experience (Figure 3.8). Such large errors are likely to be systematic rather than random and reflect an error in data analysis, such as using only development wells to model the overburden. Smaller errors are likely to reflect horizon miss-picks in areas of poor seismic imaging. Handling structural uncertainty in the model build will be covered in a later section on uncertainty management.

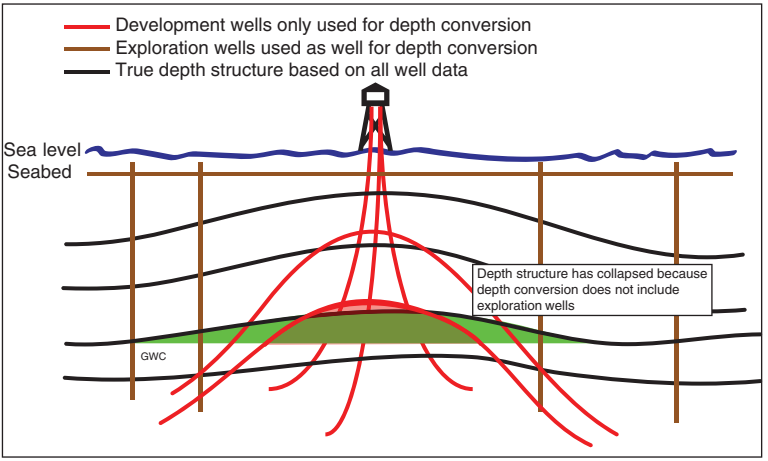


Figure 3.8 The impact of only using development wells in depth conversion; the structure collapses because the depth conversion is based on a limited overburden distribution because offset wells are not included. In this case, the hydrocarbons in place were reduced by 30%.

3.6 Summary

Building the structural model can be a time-consuming part of the whole process, so it pays benefits to start with the main structural features of the field. Construct a robust framework based on one or two interpreted horizons and the major bounding faults before adding more detail. If the model is to be used for dynamic simulation, a simple grid based on these elements might be the best solution, the detail could be introduced through facies modelling.

4

Stratigraphic Model

The reservoir framework is completed by the addition of stratigraphic levels represented by seismically interpreted horizons/events and geologically significant surfaces identified in well data: where the levels are identified in both data sets, then the mapped seismic horizons are constrained by the well picks. All that is needed to build the reservoir framework is a top reservoir horizon and a base, ideally derived from seismic interpretation. Internal stratigraphic levels are usually calculated from correlatable horizons seen in the well data; these are often incorporated as isochore thickness maps. The internal zonation should reflect major changes in geology that have some influence on flow in the reservoir. The changes could be in the gross depositional environment, or in the type or style of heterogeneity or a change in the facies type or orientation. Getting the number of zones right will ultimately help build a robust 3D geocellular grid.

Selection of the number of horizons to use is a key component of the modelling process: in general, the fewer horizons, the better, it is generally quicker to model at a coarse scale first to determine the level of detail required to achieve the objective. This step in the structural model requires the modeller to specify the type of horizon being modelled; whether the horizon is continuous across the model, or truncated by another erosive horizon, or if it forms a base of a sequence that by definition builds upwards (Figure 4.1). These choices reflect the gross depositional setting of the reservoir sequence and the conceptual model. It is often necessary to test the relationships in the model to see if the correct sequence of events is realized.

Associated with the choice of horizon type is the decision to use a lithostratigraphic approach to well correlation or to employ sequence stratigraphic principles (Figure 4.2). The decision may

Reservoir Modelling: A Practical Guide, First Edition. Steve Cannon.

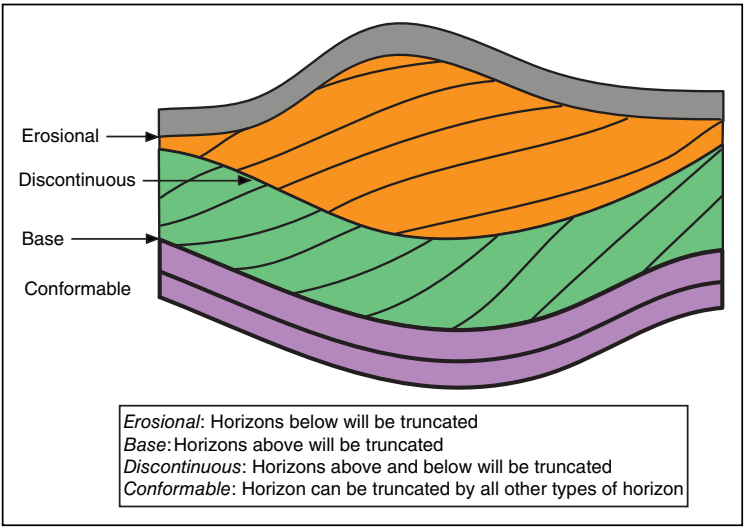


Figure 4.1 Classification and impact of different types of horizons used in modelling. Reproduced with permission of Schlumberger-NExT.

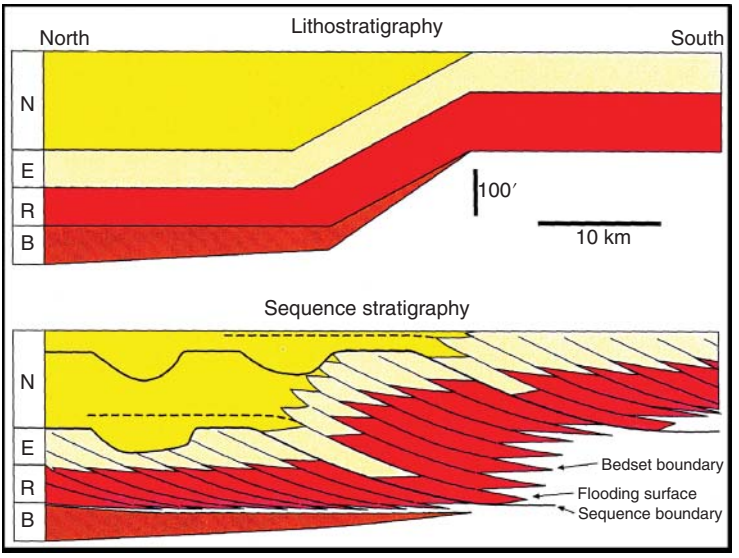


Figure 4.2 Comparison between lithostratigraphic correlation and sequence stratigraphy of the Brent Group, fluvio-deltaic system, North Sea. *Source:* Wehr and Brasher (1996). Copyright 1996, Geological Society of London.

depend on the level of geological interpretation and complexity of reservoir architecture. Generally, a chronostratigraphic approach will integrate the seismic horizons more completely into the model; therefore, a sequence-based zonation will be more effective. The correlation of well-derived correlatable events will influence reservoir body connectivity; a petrophysical approach might only correlate sand bodies or flow zones in two dimensions and ignore potential changes of facies between wells. All of these decisions depend on the level of understanding of the reservoir framework and what is required to represent geology in the model.

4.1 How Many Zones?

A zone in a grid-based modelling context is a modelling unit or sub-grid (Figure 4.3). In conventional map-based modelling, the zones are introduced to keep a certain level of vertical resolution: 3D geocellular modelling builds a grid within each zone, thus simplifying the reservoir model. In general, try to apply as few modelling units as possible, and try to use trends and/or facies within each zone instead to provide the required vertical resolution. The general approach is to apply the same zonation in a grid-based model as in the 'old' map-based models. However, we have to be aware that zones are introduced in map-based models as a substitute for the detail provided by a facies model. The common pitfall is to model too many zones.

4.2 Multi-Zone Grid or Single-Zone Grids?

Models can be built as single-zone grids (SSG) or multi-zone grids (MZG) depending on what is required by the modelling team: speed, accuracy, simplicity and so on.

Reasons for using MZG:

- Everything is stored within one zone container.
- Operations can be performed on all zones at the same time or separately.
- Fault modelling will be easier, as the grid construction is performed for the full reservoir. With SSG, it is possible to generate faults that are inconsistent from one zone to another.

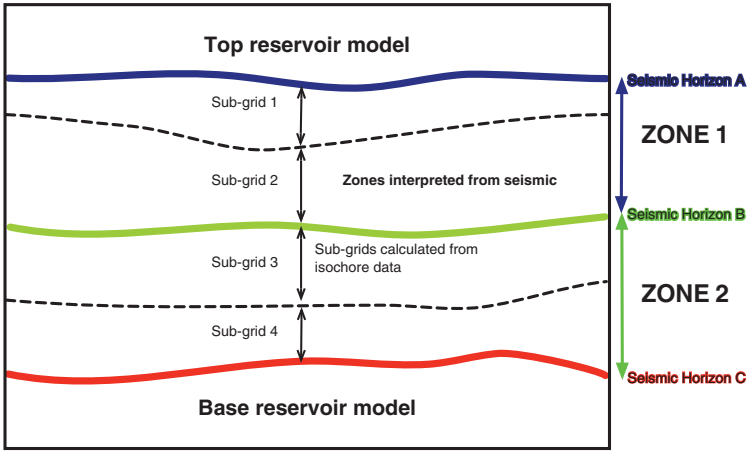


Figure 4.3 Horizon, zone and sub-grid nomenclature used in geocellular modelling.

Reasons for using SSG:

- If only one or a few zones are of interest for a particular study, it is much faster to work with SSG than a huge multi-zone, both for visualization and calculations.
- You can easily choose independent well data sets for each zone for conditioning. For instance, if well tracks are good in some zones whereas poor in other zones, you can make flexible choices.
- With MSG, you have to use the same XY grid resolution on all your zones. This means that if a zone needs a particularly refined XY grid, all other zones will have to be built with that resolution.
- Using SSG makes it possible for several people to work with different zones at the same time.

Having successfully built a number of SSG, it may become necessary to combine them into a single multi-zone grid: although this is possible, it can be fraught with difficulty, better to design the grids as required to begin with.

4.3 Well-to-Well Correlation

This step in the workflow used to be the domain of the specialist stratigrapher; however, with the advent of workstation correlation tools, the generalist was able to take over the job. The product of well correlation provides a fundamental constraint on the reservoir framework; hence, as it is a deterministic element of the model, you cannot afford to get it wrong. The key workflow activity is defining those surfaces that can be identified across the field in *every* well that is to be used in the model, unless erosive events are recognized. The surfaces may be chronostratigraphic, lithostratigraphic or based on pressure data; they should not be just 2D correlations based on petrophysical layer average data. Well correlation should also be done using TST (true stratigraphic thickness) as the reference because TVD (true vertical depth) will stretch/squeeze the thickness, especially of highly deviated wells (Figure 4.4).

Well correlation leads to zonal attribution in the model, thus should be kept simple and reflect the conceptual model and explain the observed differences in thickness of a zone between wells. After picking a specific marker in a well, a depth map should be generated; the map will reveal any anomalous picks, allowing the modeller to review the well pick with the geologist. Isochore maps should also be generated to look for trends in the data or unexpected thickness

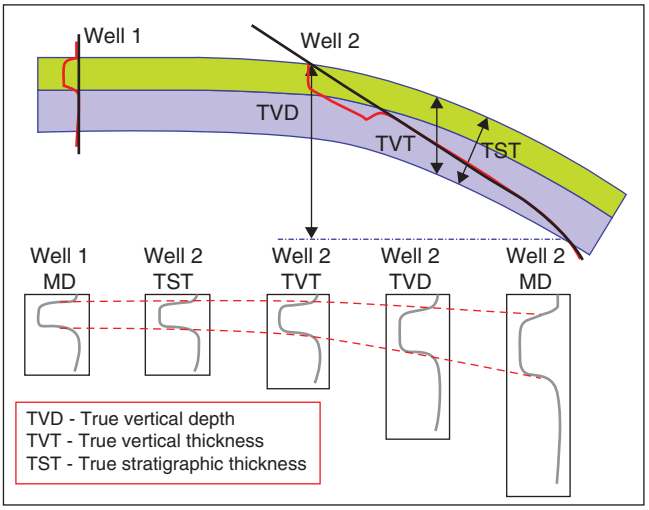


Figure 4.4 Depth reference terminology for use in well correlation.

changes. Isochore maps become a key construction element in building the detailed reservoir framework where there is sufficient well data to use geostatistical mapping tools to create the map.

4.4 Geocellular Model

The structural and stratigraphic models provide the skeleton of the reservoir framework and comprise the largely deterministic element. The geocellular model, a generic term often used to describe any 3D model, provides the fine-scale internal architecture of the reservoir that will ultimately be populated with facies and petrophysical properties. The definition of the internal architecture should not be done without reference to the conceptual depositional model and, to a large extent, the dynamic properties of the reservoir.

The volume between the deterministic layers is filled with cells that are designed to reflect the patterns of deposition of the sediments and also the size of definable facies associations. Thus, packages of sediments that on-lap, off-lap, down-lap or are truncated can be modelled in a vertical sense. If the shape and size of particular facies bodies are to be modelled, then these parameters should be used to define the cell dimensions. It is at this stage that the sedimentologist can best influence the design of the model.

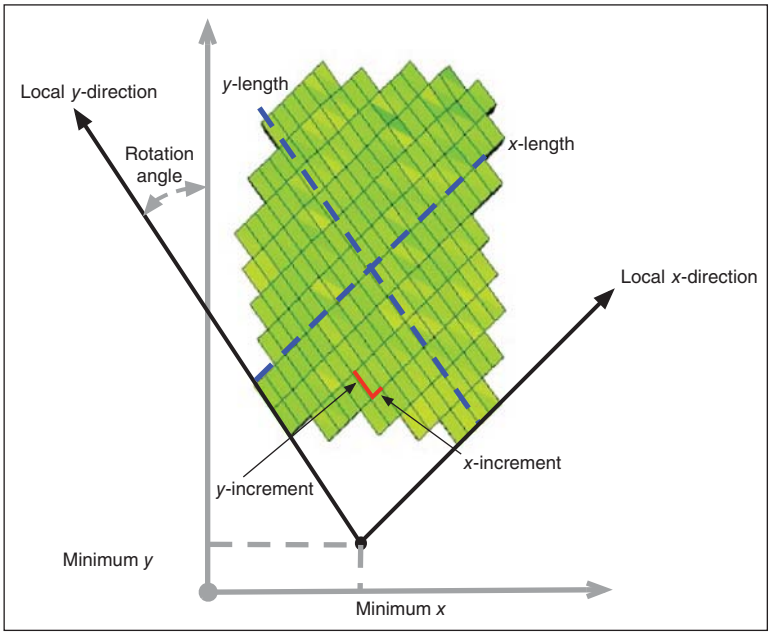


Figure 4.5 Grid orientation and axes nomenclature used in geocellular grid construction. *Source:* Reproduced with permission of Emerson-Roxar.

Varying the *xy* dimension of the cell in a particular direction can capture evidence of flow anisotropy. The reservoir engineer should use existing dynamic data to help align the overall model structure with the primary flow direction. If the concept of flow units is to be adopted, then some idea of the controls on their distribution should be included in the modelling grid (Figure 4.5).

4.4.1 Capturing Heterogeneity

Before building the final grid, it is necessary to decide the scale of heterogeneity that affects fluid flow. This is a function of the geology and the hydrocarbon fluids to be modelled dynamically. In general, this will be dictated by the following:

- Does the available data resolve the heterogeneity at the scale intended?
- Will the grid block dimension properly capture the heterogeneity being modelled?

- Is there sufficient time to build a fine-scale model and is it required?
- Do you have access to appropriate modelling tools?
- And what is the impact of the heterogeneity being modelled on flow?

In the end, it is a matter of permeability, fluid fill and production mechanism; as permeability heterogeneity increases beyond one order of magnitude, the need to build a 3D model becomes more necessary; this has been termed as 'Flora's Rule' by Ringrose and Bentley (Table 4.1). Gas fields producing under natural depletion will often only require a tank or material balance model, unless the reservoir is highly layered or the development requires horizontal or designer wells. An oilfield undergoing water injection should be modelled if the permeability varies by two or more orders of magnitude (Ringrose and Bentley, 2015).

Different heterogeneities can be effective at different scales and affect reservoir connectivity, sweep efficiency, both laterally and vertically, and the rock fluid interaction (Figure 4.6) (Weber, 1986). At the largest scale, sealing and semi-sealing faults can have a great impact on both reservoir connectivity and sweep efficiency. Facies boundaries can act as barriers to flow when the permeability contrast is significant, the change between a channel body and the floodplain. Internal sedimentological layering and lamination may act as baffles to flow, reducing sweep efficiency during both aquifer ingress and water flooding. The rock fluid interaction is a function of pore geometry and mineralogy affecting wettability and capillary pressures in the reservoir: it is at this microscopic scale that flow in the reservoir actually occurs. A few research-driven operators are prepared to model the genetic elements of the reservoir at a sufficiently small scale to try and capture the impact of laminations and pore-scale heterogeneity.

Table 4.1 The requirement for building a 3D reservoir model increases with permeability heterogeneity (1–3 orders of magnitude), fluid type and production mechanism.

Production mechanism	No aquifer support	Aquifer support	Water flood	Gas/Steam flood
3 OM K	(Model)	Model	Model	Model
2 OM K	No model	(Model)	Model	Model
1 OM K	No model	No model	(Model)	Model
Fluid	Dry gas	Condensate	Light oil	Heavy oil

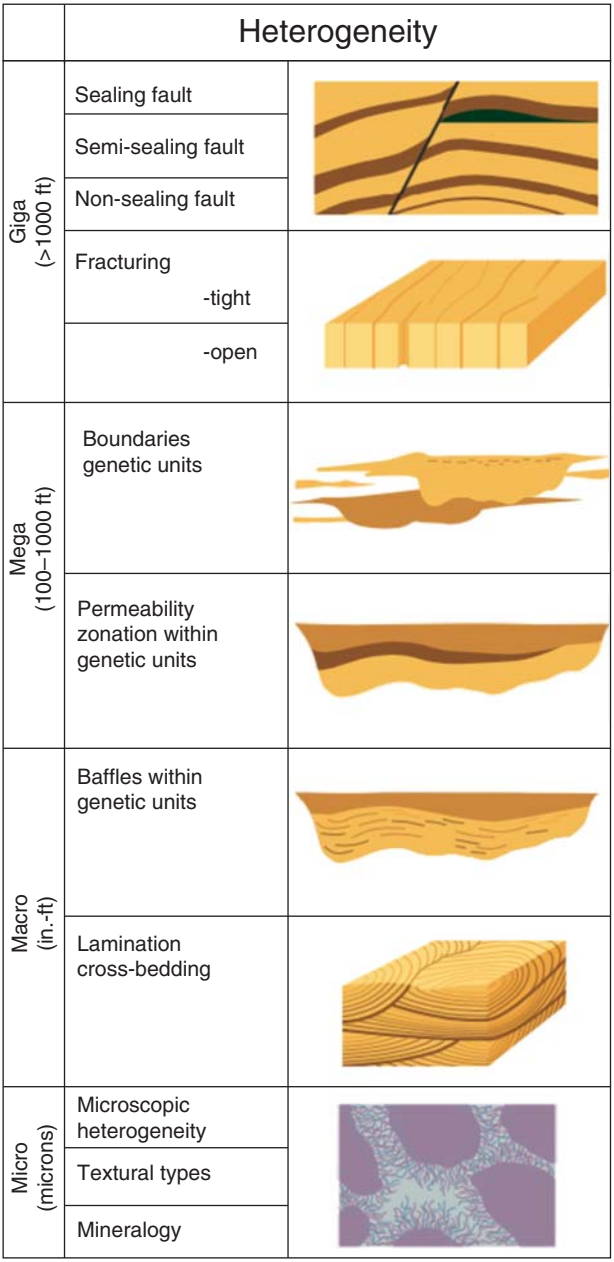


Figure 4.6 Types of heterogeneity at different scales from the microscopic to basin. *Source:* Weber (1986). Reproduced with permission of Academy Press.

The large-scale architecture of reservoir and non-reservoir units is a major control on hydrocarbons initially in-place, drainage and sweep efficiency. This has an impact on the volume of hydrocarbons that can be recovered. Drainage and sweep efficiency are governed by the connectivity of the reservoir units. This is primarily governed by the net-to-gross. The identification of genetic reservoir units (such as channels and bars) is a key step in modelling the large-scale reservoir architecture (Weber and Geuns, 1990). These units form the basis of object-based reservoir modelling techniques (Figure 4.7). The impact of large-scale reservoir architecture on flow depends not only on the nature of the architecture but also on the fluid properties and flow regime. The impact of heterogeneity on flow is accentuated if the mobility ratio is unfavourable.

In summary, keep the framework as simple as possible to ensure the most robust grid for simulation; avoid hand building the grid, it

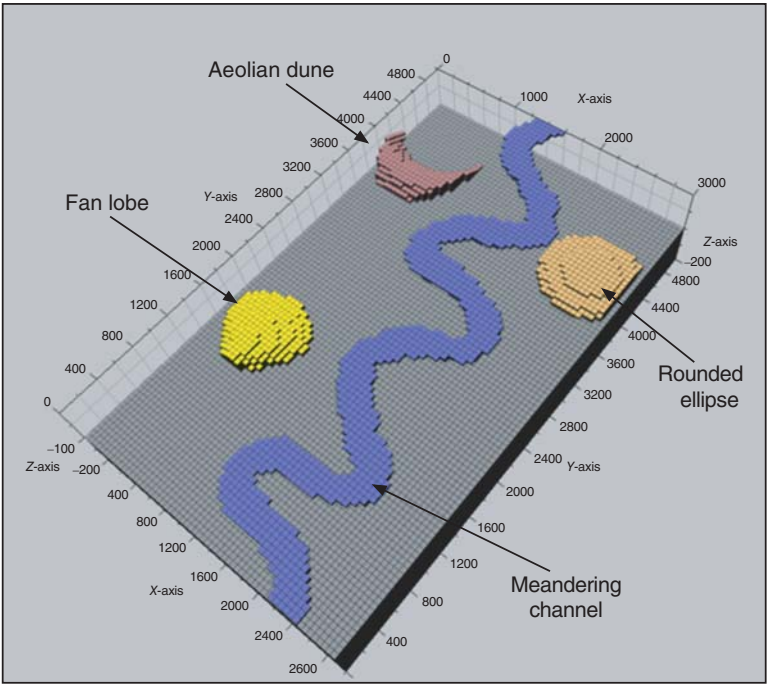


Figure 4.7 Examples of different types of genetic units that can be modelled using facies object methods.

is easier when it comes to updating the model; use model segments and zones to construct different reservoir volumes from the start as it is difficult to change the framework later; capture the large-scale heterogeneity that affects fluid flow and think about upscaling and down-gridding strategies. A robust geological grid with assigned properties is the most complete representation of the geological model and may be used for volume calculations and, in some cases, well planning. This model will usually be upscaled for dynamic simulation.

4.5 Geological Grid Design

The geological grid may be faulted (corner point) or non-faulted (XY regular), but as faults are so important for many reservoirs, the general recommendation is a faulted grid. Hence, the rest of this section will focus on faulted grids. If the upscaled geological grid with properties is to be input for reservoir simulation, it is very important that the reservoir engineer is involved in grid design.

The main product is a grid that represents reservoir geometry and is the basis for modelling of geological properties. The form of this product depends critically on the planned use of the gridded model. There are two end-members when it comes to gridding, depending on what the model should be used for:

- If the main purpose of the model is well planning or volume calculations, an accurate representation of faults is essential. The grid should then be constructed with sloped faults and irregular grid cells shaped after the exact position of the faults.
- If the main purpose of the model is construction of a reservoir simulation model, the geological grid and the simulation grid should be constructed together to minimize sampling errors in the upscaling from fine scales to the simulation scale.

It is possible to combine the purposes, being aware that the geological model created may be suboptimal for both volumetrics and upscaling to simulation level. Such a pragmatic approach can be defended in cases where accuracy around faults is of minor importance. The grid should include at least all the faults that will be included in the simulation model. Faults in the simulation grid should use the same naming convention as in the fault model.

Ideally, the axis of the geological grid should be aligned with main direction of the controlling influences on flow in the reservoir. This will

usually be the major faults or the primary depositional facies. Sometimes, grids may be aligned with the direction of horizontal wells. The axis of the grid should define a right-hand coordinate system, with the origin defined in the 'north-western corner' of the grid.

4.5.1 Goals of Geological Grid Design

The main design goal for the geological grid is of course to construct a grid system that can render the geological framework and the reservoir property model as accurately as possible. The level of accuracy must be balanced against the final purposes of the geological grid. In addition to this, some secondary design goals will always be present, and these will be discussed in detail in the following sections. As an overview, the main additional design goals can be listed as follows:

- In most software tools, reservoir property modelling is performed on a regular grid, the so-called *sim-box* and then projected from this grid into the physical structured grid. The geological grid should be designed to minimize errors that may arise in this projection.
- The geological grid should be constructed to minimize sampling errors when seismic data are used for conditioning the geological model.
- The geological grid design is very important when the simulation grid is being constructed. Minimization of sampling errors in the upscaling process should be a design goal both for the geological grid and for the simulation grid.

As the geological grid design influences both handling of seismic data and the construction of the simulation model, it is extremely important to involve both geophysicist and reservoir engineer in the design process.

4.5.1.1 Definition of Axis System

Two different axis systems are involved in the grid construction, one for a geological grid and the other for the simulation grid. The geological grid is defined as a combination of the UTM coordinates and TVD (x, y and z). The alternative coordinate system involved in grid design uses the number of cells in each direction of the grid (i, j, k). This system has its own defined origin independent of the UTM system. The local directions of this system will vary with the local directions of the grid lines.

The (i, j, k) coordinate system should be defined so that the axes form a right-handed system; defining the origin in the north-western corner of the model can achieve this. The origin should be placed in the same corner in the geological and in the simulation model, to avoid confusion. The strict definition of the axis system is enforced to avoid having to redefine the grid and the properties later in the modelling process.

4.5.2 Orientation of the Geological Grid

As with grid construction in general, orientation of the grid is a compromise between several different factors of both input data and results.

4.5.2.1 Orientation from Seismic Lines

Seismic data will be collected along seismic lines with a global direction relative to the field. If data from the seismic cube are to be used to condition the geological model, it is preferential to orient the geological grid in the same directions as the survey to minimize sampling errors. The cell length in the direction normal to the seismic lines should then also equal the distance between the seismic lines. Ideally, the grid should then be completely regular.

4.5.2.2 Orientation from Major Faults

If an exact representation of faults is attempted in the grid, cells will always be somewhat distorted in the vicinity of faults. Stochastic modelling assumes that all geological grid cells are close to equal size, and an error is introduced if grid cells are deformed too much. This error is reduced if the grid can be constructed to follow major fault directions, so that the number of grid cells that are deformed to fit the fault pattern is minimized.

4.5.2.3 Orientation from Geological Features

The geological data will generally reflect some degree of anisotropy, for instance, in properties such as permeability and variogram range. This anisotropy usually reflects the major trends in the depositional system, for instance, parallel and normal to the main channel directions in a fluvial system.

Geological anisotropy must be modelled based on the local axis in the (i, j, k) system in the geological grid. The direction of the geological grid should then be selected to coincide with the characteristic

geological directions. A common problem is, however, that geological orientation changes from zone to zone. And it is almost impossible to have grids with varying directions for each zone. The recommendation is then to follow the geological features in the most important reservoir zone(s).

4.5.2.4 Orientation from Simulation Grid

Sampling errors typically occur when properties are upscaled from the geological grid to the simulation grid. This error is minimized if grid cells in the geological grid and the simulation grid match each other. Construction of a simulation grid usually involves flow considerations (e.g. following wells), which is not an issue for the geological grid. To create a correspondence between the two grids, these considerations should also be taken into account for the geological grid.

The various issues influencing orientation discussed in the previous sections are often in conflict with each other. If a ranking of these conditions are needed, orientation from geological features and simulation grid are most important. In addition, there is a more practical consideration to minimize the number of cells. Therefore, in order to optimize computation speed and visualization speed, it is advised to select a direction that makes the geological grid as small as possible, in terms of numbers of cells.

4.5.2.5 Cell Sizes and Total Number of Cells

Ideally, grid size should be selected small enough to capture the smallest geological feature required in the model. The Nyquist sampling theorem (used in geophysics) suggests that the grid cell should not be larger than half the length of the smallest feature, to avoid aliasing (erroneous sampling). This typically leads to a vertical resolution of 0.5–2 m grid cells. Aliasing is a phenomenon that occurs when an analogue object is sampled to a digital representation. If the sampling is performed with too low resolution, the objects are not rendered correctly, and large distortion may occur in the digital representation.

Unfortunately, the areal grid size must typically be a compromise according to the total machine memory available for the model. The total number of cells depends on machine capacity and the patience of the user. This will change from year to year, as hardware is improved. By using a prototyping procedure to test the model construction, a much smaller grid can be initialized; this can be done by selecting a sector of the reservoir. At an initial stage, test the modelling workflow on a grid with less than 500,000 cells.

4.5.3 The SmartModel Concept

The SmartModel concept is an approach where the team designs an optimum grid and then constructs the fine-scale and coarse-scale grids from this by downscaling or upscaling. The purpose is to achieve as fine correspondence as possible between the geological grid and the simulation grid, thereby reducing sampling errors in the property upscaling between the grids. The grid correspondence is especially important for fluvial reservoirs, where sampling errors can ruin channel communication completely.

Typically, the geological grid will be selected as the SmartModel grid, and the simulation grid is created from this by coarsening. This alternative gives the best fault resolution in the simulation model. The fault representation in the two models will however not match exactly. Alternatively, the simulation grid is selected as the SmartModel grid, and the geological grid is constructed from this by refinement. The fault resolution in the geological model then follows the simulation grid resolution.

The discussion so far has concerned the areal resolution, but the same refinement/coarsening approach is valid for the vertical direction. If the geological model has low resolution in a selected zone, as in a map-based model, the simulation model may use a refined layering for this zone, even though the areal grid was achieved by coarsening the geo grid. Hence, refinement/coarsening in the horizontal and vertical directions are independent.

The SmartModel grid concept has several advantages:

- A single grid is constructed and this simplifies work.
- There is consistency between geological grid and the simulation grid ideal for upscaling.
- Differences in bulk volumes between the various grids are small.

There are, however, also some disadvantages:

- Faults in the geo-model may have to be approximated as zigzag features in cases where grid direction is not coincident with fault directions.

4.6 Layering

Several vertical gridding or layering methods are available in most software tools; layering introduces the vertical thickness component

of the cells by allowing the user to select either constant thickness or constant number of layers. These are selected to represent different geological situations such as on-lap, down-lap, erosion, or differential compaction (Figure 4.8). In effect, we are attempting to represent stratal layering in the model to capture the large- to medium-scale structures in the reservoir units. Most geological sequences have a natural hierarchy to them, and how we correlate these sequences can influence model design. For example, an incised valley has a length scale of tens of kilometres, but the channels filling the valley will be generally smaller and more sinuous and be made up of even smaller metre scale units. Capturing the right scale of hierarchy can influence the scale and nature of heterogeneity in the model.

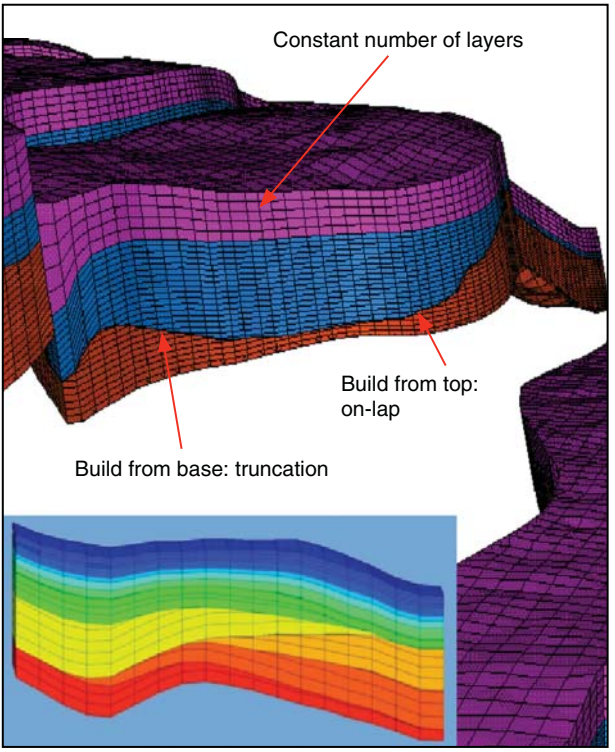


Figure 4.8 Different types of layers used in geocellular modelling. *Source:* Reproduced with permission of Emerson-Roxar.

There are different types of vertical gridding patterns and these are discussed fully in the software manuals, but the following options are commonly seen in models:

- Layer-conformable grids are typically used to mimic truncation/off-lap or on-lap/down-lap sequences; the cells will be of constant thickness.
- Typically, a transgressive sequence will have strata on-lapping its base that may be mimicked by a top-conformable grid, assuming here that the uppermost strata may be structurally approximated by conformable gridding.
- A highstand system tract tends to become eroded if it is followed by a lowstand, that is, strata are truncated by the top surface. A base-conformable grid may mimic this if conformity may be assumed at the base.
- Proportional or conformable layering is used for laterally extensive sheet-like bodies or to replicate differential compaction in a shale sequence; in this case, there will be a constant number of cells in the vertical stack.

Pseudo-surfaces, extrapolated surfaces or air interpretations may be used to combine conformable gridding with erosion/off-lap or on-lap/down-lap structures. Ideally, each geological grid should be based on four surfaces, that is, two for conformable gridding, one for approximation of erosion/off-lap structures and one for approximation of on-lap/down-lap structures. The way in which cells are attached to the bounding surfaces will also have an impact on grid orthogonality; cells are attached as stair-stepped, against the surface or truncated (Figure 4.9).

4.6.1 Potential Dangers Using Conformable Grids

If a top- or bottom-conformable grid type is used, faults that are represented only as flexures in the horizons can create special problems. If a grid pillar is located inside the fault region, the use of a conformable grid type can lead to a large number of grid cells in the vertical direction.

As the geo-modelling is performed in an idealized grid (the sim-box) with the vertical dimension equal to the maximum number of grid cells in the physical domain grid, the un-split fault can lead to an unnecessary, large numerical problem slowing down both calculations and data transfer. The problem may be avoided if large faults are

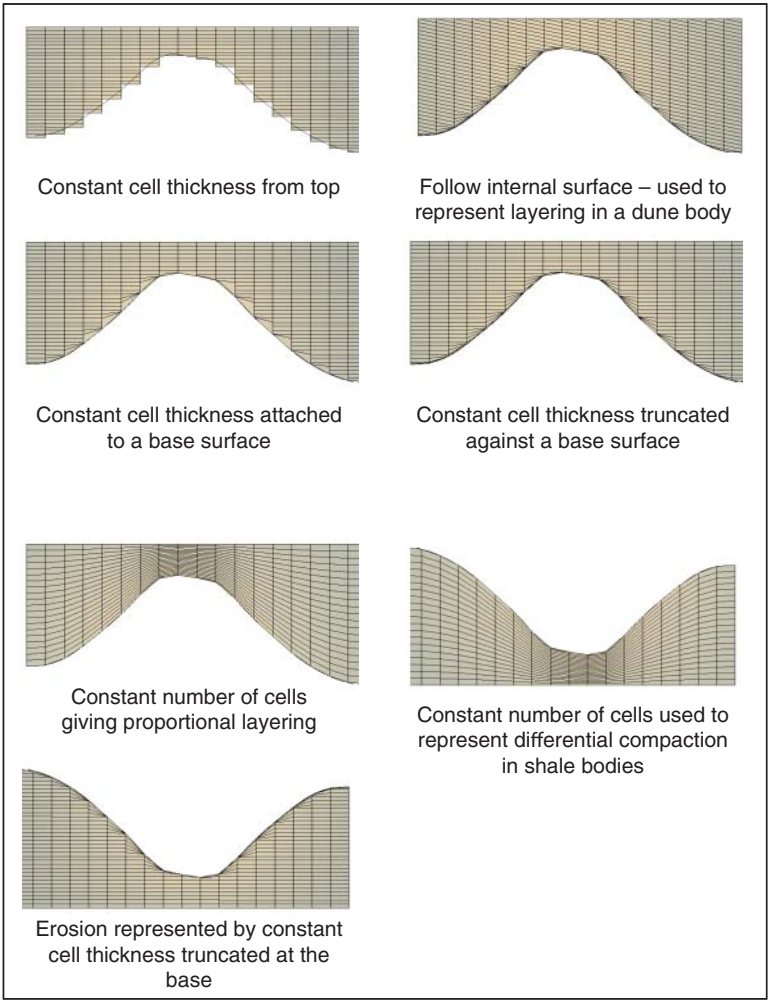


Figure 4.9 Different layering and surface attachment methods used to represent medium-scale geological features. *Source:* Reproduced with permission of Emerson-Roxar.

represented with separate fault planes and cut-off lines. Carefully check the maximum number of grid cells produced in the vertical direction!

4.6.2 Erosion

Eroded formations create a special difficulty for the vertical grid generation, as it is difficult to simultaneously model the existing horizons correctly and to get a proper representation of geological objects between the horizons.

The geological objects will typically have an orientation given by original depositional conditions, also reflected in the surfaces that existed before the erosion took place. If a proportional grid is used between the (partly) eroded surfaces, the geological objects will not be parallel with the grid layers and can thus be poorly represented in the resulting grid. A proportional grid is therefore generally not a good choice for an eroded zone.

Two different solutions are presented for a better grid representation: a resource cheap solution using eroded surfaces and bottom conform gridding and a better, more resource-intensive solution using air-interpreted surfaces and proportional gridding.

4.7 Grid Building Workflow

1. Firstly, define the areal extent of the model (AOI); find out from the reservoir engineer whether the aquifer needs to be included in the model for future dynamic simulation of drive mechanism. If the model is of the hydrocarbon-bearing interval, the number of cells required can be reduced or a fine-scale model can be built.
2. The bounding horizons of the reservoir model should be checked for any holes or anomalous spikes in the data; these should be corrected before proceeding. Incorporate the intervening horizons forming the sub-grids and check these for unexplained thickness variations.
3. Define the number of layers in each sub-grid by analysing the required cell thickness from the well data; decide on the geometry of the layers and define the cell thickness.
4. Select all the faults to be included in the fine-scale grid; any faults in the simulation grid must also be included in the fine-scale grid.
5. As an easy QC step, calculate the gross bulk volume for the grid and compare with the expected volume from previous volumetric estimation; do not be alarmed if this is marginally different than expected, but be concerned about large discrepancies.

4.8 Quality Control

Most software tools have built-in grid QC tools for checking the suitability of the resulting grid for further modelling (Figure 4.10).

A checklist for quality control of geo-grids:

- Identify maximum number of grid cells in the vertical direction in each zone.
- Plot distribution of areal grid size DX and DY: ideally, there should be a small variation in these quantities, as geological modelling assumes a uniform distribution.
- Perform visual inspection of fault representation in the model.
- Check for twisted grid cells (inside/out cells), as these cells will lead to erroneous volume calculations.

Deliverables after this stage of modelling should include the visualization of the top structure in 3D, the intersection of well paths with the structural envelope and the internal structure, and a true spatial model of fault geometry with the reservoir volume.

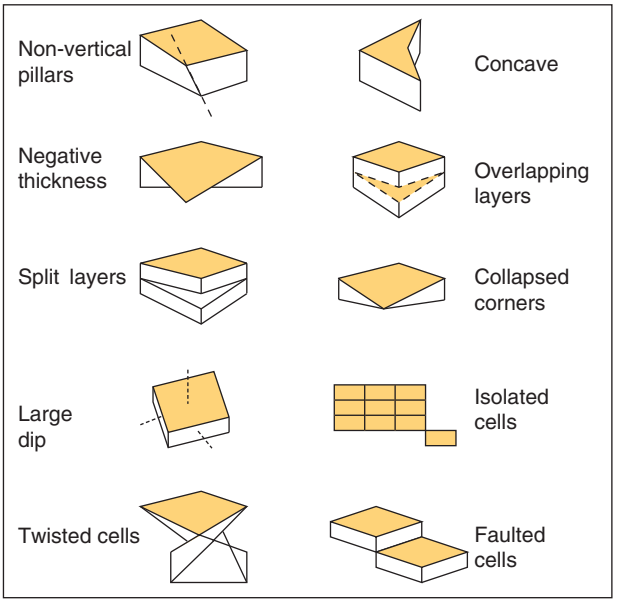


Figure 4.10 Grid cell quality control examples of imperfect cells that reduce the efficiency of dynamic simulation. *Source:* Pitchford (2002). Reproduced with permission of PESA.

The next stage in the workflow links the grid to the well data along the well path; this is termed *blocking* or *upscaling* the well data into the grid. This process will be discussed fully in the next chapter, but it is often a good practice to check whether the grid is refined enough to capture the important reservoir properties such as high-permeability streaks or cemented layers.

4.9 Uncertainty

The main uncertainty in the stratigraphic model is errors in the correlation scheme; fewer deterministic horizons reduce this uncertainty, so keep the zonation scheme simple! Where the main zone boundaries are from seismic interpretation, then there will be an element of uncertainty away from the wells due to depth conversion and horizon picking. The geophysicist may be able to assess the degree of uncertainty to allow a stochastic approach to the horizon model for each sub-grid; this can be fraught with danger especially if there are too many closely spaced horizons, leading to boundaries cutting each other and disrupting the grid integrity. Proceed with care when building stochastically defined horizons.

4.10 Summary

Building the final geocellular grid marks a fixed deliverable in the project workflow. Before continuing with populating the model, all stakeholders should be involved in the sign-off of the reservoir framework: are the key faults included; is the grid fit for purpose, does the layering reflect the conceptual model? All these questions will be predicated on the primary purpose of the model build: volumetric estimation, well planning or dynamic simulation.

5

Facies Model

The objective of the facies model is to incorporate the medium-scale reservoir heterogeneity represented by the sedimentary geology into the architecture of the geocellular grid. The resulting model should be suitable for deterministic or stochastic property modelling. If the structural model represents the framework of the reservoir, then the facies model represents the internal architecture, constrained by the geocellular grid. The facies model is implemented to capture the heterogeneity of a reservoir as defined by the interpreted depositional model constrained by well data or seismic attribute data. In 3D, the facies model translates the traditional mapped palaeogeography of a horizon into a representative volume, thus improving the description of the relationships between different facies: the facies model should always honour Walther's law of superposition (Figure 5.1), which implies that a vertical sequence of facies will be the product of a series of depositional environments that occurred laterally adjacent to each other. This law only applies to situations where there is no break in the sedimentary sequence.

We build a facies model to simplify the property model, inasmuch as that each facies should represent a unique petrophysical distribution; to achieve this, it requires core data to calibrate the wireline logs and a facies scheme representative of the conceptual depositional model. Do not forget that 'facies' is a discrete random variable. Using a facies model helps to introduce smaller scale heterogeneities in the distribution of petrophysical properties. Using a stochastic process to populate the facies model allows the modeller to test the predicted proportion and distribution of any facies. It is not sensible to have more than 4–5 facies in a sub-grid of the model as it is unlikely that the differentiation of petrophysical properties will support more; if more are deemed necessary, then a revised zonation is indicated. While

Reservoir Modelling: A Practical Guide, First Edition. Steve Cannon.

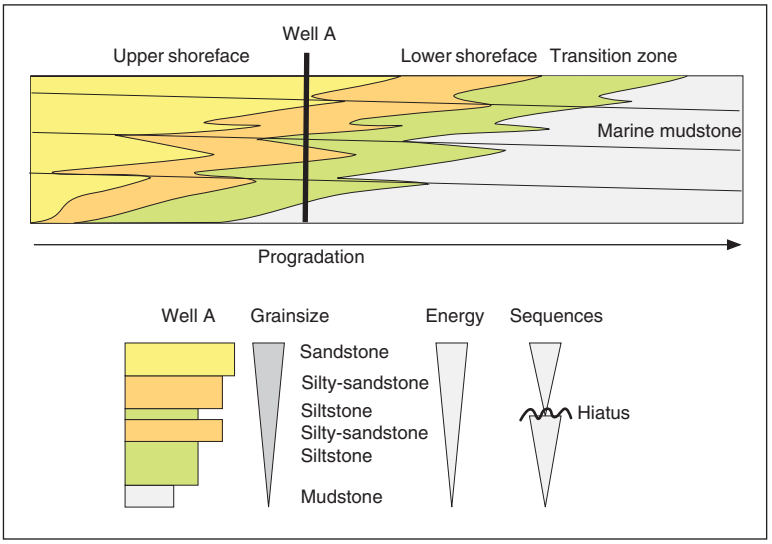


Figure 5.1 Walther's law in action; facies found adjacent laterally will be seen in the same order vertically. This example is of a progradational shoreface marine sequence.

the sedimentologist should be encouraged to describe the cores in as much detail as possible, the team should decide on the required level of detail in the model. The reservoir engineer will be unlikely to have sufficient relative permeability and capillary pressure information to model more than 5–8 rock types in a complex dynamic simulation.

Most hydrocarbon reservoirs are found in either clastic or carbonate environments; on the basis of the global distribution of oil, carbonate reservoirs are more important, but much more difficult to model. This section will focus on different clastic environments and how you might model them; we will deal with carbonates later, but the same principles apply.

5.1 Facies Modelling Basics

So you have decided to use a facies model to constrain reservoir properties; what do you need to have to build the model? Firstly, a facies scheme developed from core data; next, a facies log for each well; and finally, a gross conceptual model that integrates the whole thing. I strongly recommend the volume 'Facies Models Revisited' as an excellent reference for understanding the types of different models

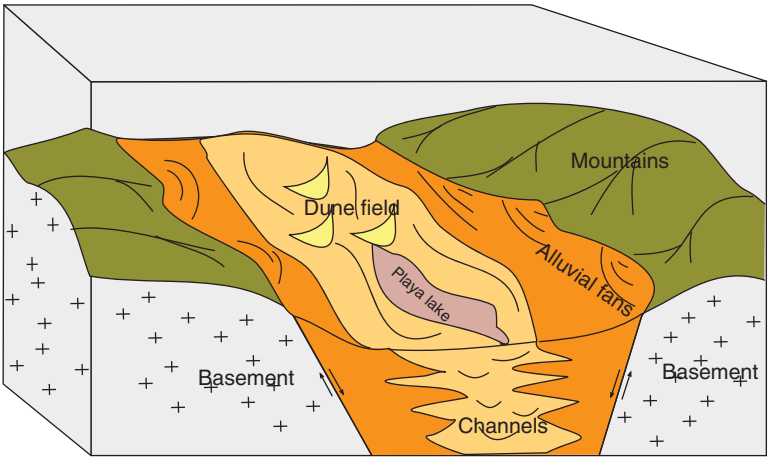


Figure 5.2 Conceptual model of a desert setting including sand dunes, dry channels, alluvial fans and playa lake environments.

that might be conceived (Posamentier and Walker, 2006). Assuming that you know the gross depositional environment, where do you start with developing a facies model? What genetic bodies are likely to be present? What are their size, geometry and orientation? What smaller scale facies might be recognized that warrant modelling? What are the proportions of these smaller scale elements and their relationship to each other? Can you draw them?

Take, for example, the desert environment, comprising wind-blown sand dunes, inter-dune sands and clays, large-scale playa lakes with fringing alluvial fans and channels (Figure 5.2). How many of these facies associations have been recognized by the sedimentologist in the cores? How do they differ in geometry, distribution and reservoir properties? Can they be recognized in the wireline logs? What smaller scale units can be identified? What possible facies have *not* been identified in core that might exist (a known unknown?)? This same thought process could be applied to all depositional environments to develop a template to manage the process of facies recognition.

Using the conceptual model plus well data, the sedimentologist can provide a facies breakdown to be modelled. Turning this detail into a usable scheme for 3D facies modelling requires two key steps, firstly in analysis and secondly in application:

- Qualitative and quantitative analysis of trend information from logs and well data. This should be used to give a deterministic understanding (low frequency) of parameter variation such as

facies proportions and flow properties; any observed trends should be explained sedimentologically. This process can be used as part of the well data quality control. Any vertical and linear trends in facies or property data should be recognized and explained.

- Perform blocking of well data; the first step in upscaling from raw log data: there are usually a number of methods with which to block the wells. Conditioning on dynamic data should be delayed to a history match of the simulation model, but well test data could be used for quality control. Perform quality checks before further modelling including a comparison of raw and blocked data.

Geological modelling is essentially the filling of the fine-scale geological grid with petrophysical properties. Modelling discrete facies is a way to improve the petrophysical model and is an essential task where reservoir property distribution is a function of the sedimentary depositional system. Selection of the basic modelling parameters is a combination of detailed sedimentology and regional depositional models. The modelling procedures are very much dependent on the available software routines and on the complexity of the modelled reservoir volume. The reservoir properties can be modelled using deterministic, stochastic-deterministic or stochastic methods with all well observations being honoured in the process. The modelling process at this stage requires strict quality control both visually and quantitatively.

5.1.1 Defining the Facies Scheme

The first step in the workflow is to decide in what depositional environment the reservoir was deposited: continental, transitional or marine. In each of these gross environments, we can predict the type of geological bodies likely to be present, their distribution and their associated facies. This should all have been considered in developing the conceptual model. Detailed core descriptions and calibrated wireline log interpretations should identify the types of facies present in the well data and their vertical and lateral relationships: this amounts to building the depositional model on paper, and if you can draw your model, then you will be able to build a 3D geocellular representation. Where well data are limited, it may be sufficient to build a simple sand/shale model based on a gamma ray cut-off, but some idea of the proportion and distribution of each facies should be attempted if only to test the uncertainty in net-to-gross.

Not all wells are cored, and core coverage is seldom complete in a single well, so it necessary to interpret the facies in the uncored

intervals. This is another reason why a limited number of facies should be used. The options available are to interpret the facies by hand using characteristic log responses (Figure 5.3a) or to use some mechanistic approach (electrofacies) (Figure 5.3b): if there is a limited number of wells, I would always take the former approach, but when you are dealing with tens of wells, some sort of automated log-derived facies analysis is sensible.

Electrofacies discrimination allows us to extend interpretation of reservoir facies into uncored intervals while trying to honour the link between sedimentology and petrophysics. However, because the approach is based on individual log values at each measurement increment, the changes are often too rapid to be used sensibly in subsequent geological modelling. It is probably of greater value to interpret lithology alone and to allow the geologist to group the results as facies associations representing specific depositional packages.

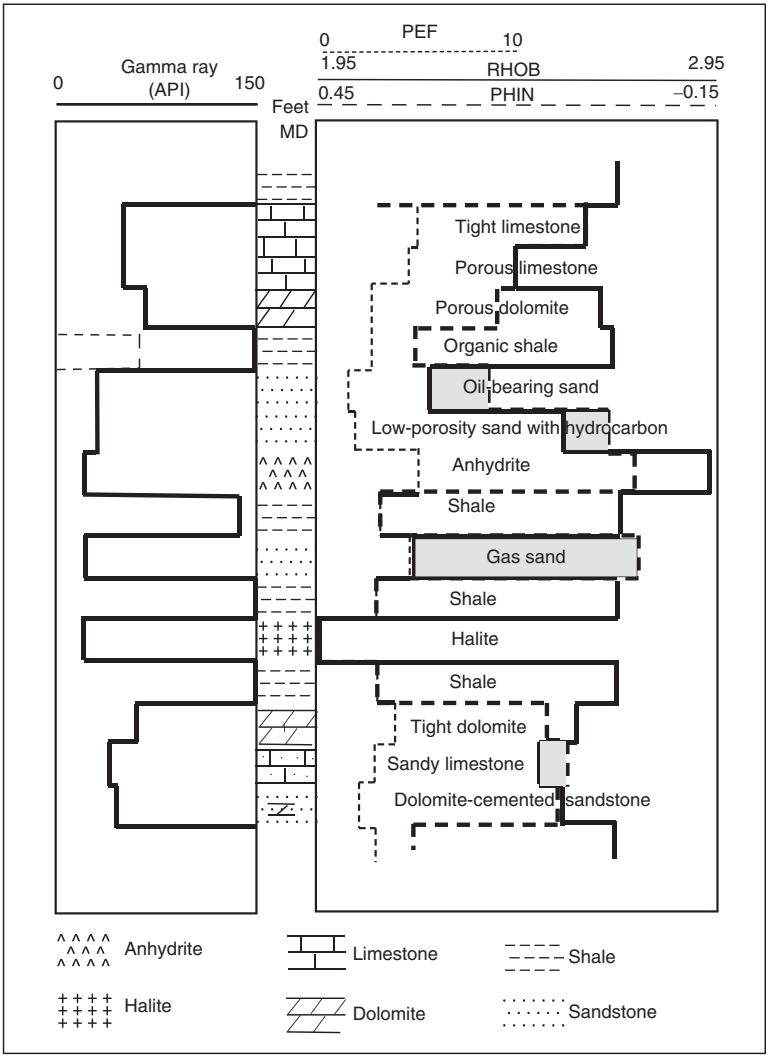
Most log analysis software products have built-in solutions to determine lithology from different logs either through solving multiple simultaneous equations or some stochastic solution; these often determine porosity at the same time. Some tools have sophisticated statistical methods including fuzzy logic, cluster analysis, principal component analysis and neural networks to determine different electrofacies. All of these methods depend on robust input training sets based on core description if they are to be used successfully; without calibration to core or cuttings, the results cannot be validated and should be treated with skepticism. Even where input data are core constrained, the success of facies recognition is only about 80% correct and where there is no core about 60% correct even if the training set is well constrained.

In either simple or complex mineralogical/porosity associations, the log responses for any zone may be related to the sum of the proportions of the components, each multiplied by the appropriate response coefficients in a series of simultaneous equations (Doveton, 1994). The equation for each log takes the form:

$$c_1 v_1 + c_2 v_2 + \cdots + c_n v_n = l$$

where:

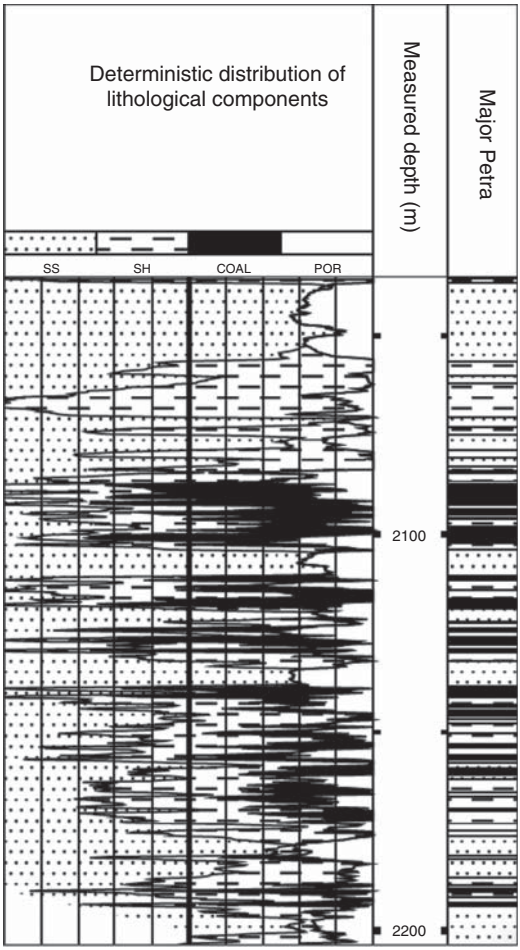
n	=	number of components
v_i	=	proportion of the ith component
c_i	=	log response of the ith component
l	=	log response of the zone



(a)

Figure 5.3 (a) Simplified lithology determination from wireline logs; natural gamma, bulk density, photoelectric and neutron porosity logs. *Source:* Cannon (2016). Copyright 2016, John Wiley & Sons. (b) Computerized lithology interpretation using a deterministic electrofacies algorithm. *Source:* Cannon (2016). Copyright 2016, John Wiley & Sons.

Figure 5.3 (*Continued*)



(b)

For example, in a limestone–dolomite–anhydrite–porosity system with density, sonic and CNL logs, the number of components (m) is 4, the number of logs (n) is 3 and the n log equation might be:

$$2.71\ v\_\text{ls} + 2.87\ v\_\text{dol} + 2.98\ v\_\text{an} + 1.00\ \text{PHI} = 1\_\text{den}$$

$$47.5\ v\_\text{ls} + 43.5\ v\_\text{dol} + 50.0\ v\_\text{an} + 189.00\ \text{PHI} = 1\_\text{son}$$

$$0.00\ v\_\text{ls} + 7.50\ v\_\text{dol} - 0.20\ v\_\text{an} + 100.00\ \text{PHI} = 1\_\text{cnl}$$

where PHI = v_por (volume of porosity)

Because of material balance, the proportions of the components sum to one:

$$v_1 + v_2 + v_3 + \cdots + v_n = 1.00$$

In the example:

$$v\_\text{ls} + v\_\text{dol} + v\_\text{an} + \text{PHI} = 1.00$$

In this example, there are $n = 4$ equations ($n = 3$ for the logs plus the unity equation) and $m = 4$ unknowns (the proportions of each component).

Rewriting these equations in matrix algebraic terms:

$$C \cdot V = L$$

In the example:

		C	V	L
2.71	2.87	2.98	$\mathbf{V}_{\text{ls}}$	$\mathbf{1}_{\text{den}}$
47.50	43.50	50.00	$\mathbf{V}_{\text{dol}}$	$\mathbf{1}_{\text{son}}$
00.00	7.50	−0.20	$\mathbf{V}_{\text{an}}$	$\mathbf{1}_{\text{cnl}}$
1.00	1.00	1.00	PHI	1.0

The matrix formulation is a linear model and generally provides a satisfactory first approximation for compositional solutions, as confirmed by core analysis and laboratory studies. However, the borehole environment, the tool design characteristics and the physics of the measurement variable introduce various sources of non-linearity. Local-fit linear models can easily accommodate obvious non-linear functions, such as those relating the pore volume to the neutron response.

The matrix algebra concisely relates the information available and the degree of complexity of the component association. Each log provides a single equation, and the collective set is supplemented by the material balance equation (unity equation). When the number of logs is n, the number of equations is $n + 1$, which can be used to resolve $(n + 1)$ components uniquely; in this situation, the system is 'uniquely determined'. If the number of logs is inadequate, the system is 'under-determined' and the solutions are downgraded to estimates

stipulated by external constraints, or by prior geological knowledge. If the number of logs exceeds the minimum requirement, the system is 'over-determined' and a solution must be chosen which is most consistent with all the available data. The algorithms used to resolve these three possible states of determinacy have strong structural similarities and are reviewed in Doveton and Cable (1979).

5.1.2 Upscaling of Log Data (Blocking Wells)

Before the well data can be used for modelling, it must be scaled up to the vertical resolution of the 3D grid; this applies to both facies and property data (Figure 5.4). Blocking of wells is the term used for the process of upscaling from log scale to the geological grid scale. The facies property is a discrete random variable, it is finite property, ranging from 0, …, n, where n is a whole number, hopefully not

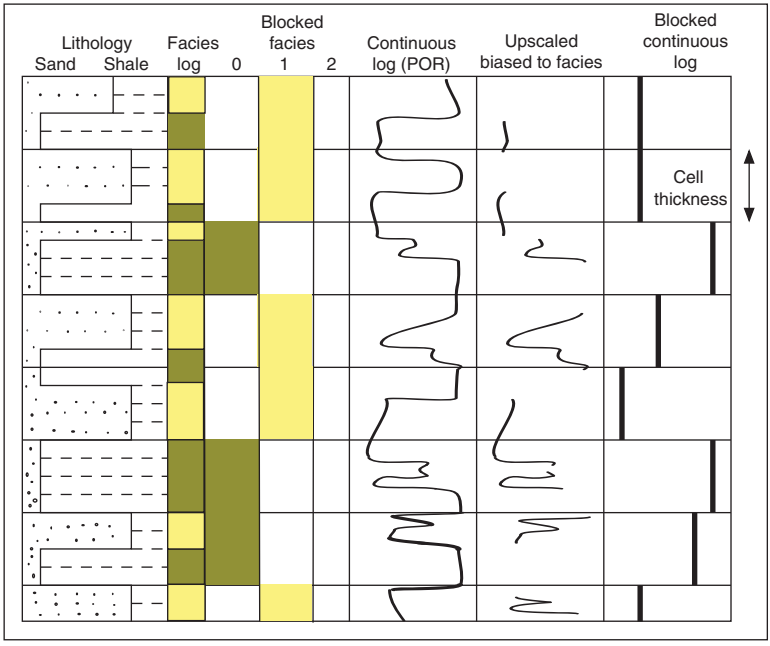


Figure 5.4 Upscaling or blocking raw discrete (facies) and continuous (porosity) well data.

greater than 5! Raw log data are normally sampled every 6 in. (15 cm), grid cells are usually larger in the vertical direction. A note of caution: remember that you are performing an upscaling routine, this means that data will be averaged out, and important data can be lost, such as thin high-permeability streaks or thinly bedded shales, so visually inspect the results.

Preparation of the log data before the upscaling must reflect the selected method for handling non-reservoir facies types. If, for instance, it is intended to model discrete calcite nodules or dense non-reservoir zones independently, then all such observations must be excluded from petrophysical analysis characterizing the other facies types (or zones).

Blocking of wells should be performed as follows:

- Facies data should be pre-processed to remove shoulder effects.
- A zone log must be defined, that is, a log containing the zone index of the intersecting zone along the well path.
- When blocking the zone log, it may be necessary to 'shift and scale' logs (Figure 5.5) to match the sub-grids; QC the result for unreasonable depth shifts.
- Cell layer averaging is recommended for all continuous variables (porosity, permeability and so on).
- For discrete logs such as a facies log, use the 'most of' routine.
- Make sure that facies that are less than a single cell thick are captured as discrete package; this is particularly true for high-permeability streaks and carbonate nodules if they make up a significant (5–10%) proportion of the well sequence.

5.1.2.1 Blocking Core Plug Data

If you decide that blocking the raw core analysis data, this should be done with extreme care because the data are sparsely sampled and may lead to unlikely averaging of the data. The plugs may have been sampled in reservoir intervals only, leading to highly biased values of permeability and porosity. Finally, unconsolidated intervals may lack samples (not possible to get good core plugs), and this will result in missing data from very permeable intervals. All of these factors should probably have been handled at an earlier stage in the reservoir characterization process. Always check how core plugs are sampled!

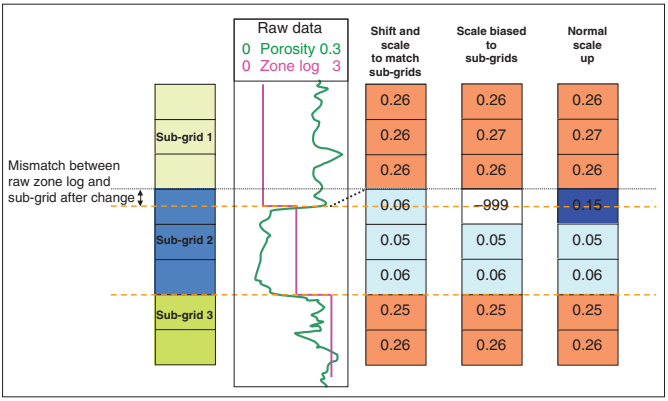


Figure 5.5 Shifting and scaling blocked well data to correct the mismatch between raw data and model sub-grids. *Source:* Reproduced with permission of Emerson-Roxar.

5.1.3 Simplified Facies Description

In some cases, a detailed facies definition may not be required for the modelling purposes: perhaps a simpler facies description can be used than the one developed as part of the depositional analysis. The following list describes cases where simplifications are reasonable:

- If the zone is a non-reservoir zone, a zonal average model may represent a sufficient simplification. The modelling becomes similar to conventional layer average modelling. Be aware of small errors in grid-to-well connection may contaminate such a model with wrong observations.
- If the zone mainly represents good upward coarsening or upward fining units with no apparent or expected discontinuities, such trends may be modelled directly in a petrophysical model, that is, creating an effective model by simply bypassing the facies model.

With this approach, trend analysis of the petrophysical distributions becomes more important, as trends are no longer captured in the facies proportions. The petrophysical analysis becomes more demanding. For geological environments where facies transitions are characterized by a strong contrast in some log response, the estimation of the vertical variogram ranges may be interpreted from such logs. The horizontal variogram normally has to be chosen in a more pragmatic way based on geological knowledge.

For each facies to be modelled, the different descriptive parameters and reservoir properties need to be properly documented in a tabulated form.

5.1.4 Verification of the Zonation and the Facies Classes

One of the objectives with the facies model is to split the petrophysical distributions into simpler classes. The resulting petrophysical distributions must therefore be inspected. Some recommended checks are listed below.

- Create histograms for porosity and permeability for each facies to see if there are outliers and confirm whether the distributions are normal. It may be impossible to create sufficient facies classes to avoid bimodality, but it is important to know whether the data are bimodally distributed.
- Create zonal average maps and do simple kriging of the data in map form to look for anomalies and trends areally.

- Repeat these operations after eventual removal of trends, that is, work on the residuals.
- Remove apparently incorrect observations. If possible, adjust the zone and facies boundaries to fit better with the petrophysical data.

5.1.5 Facies Proportions from Well Data

A trend may be looked upon as the low-frequency part of the variations in some layer properties, for instance, those caused by lateral differences in sediment source types, vertical variations in overburden pressure and so on. The proportion of a facies type within a zone may vary laterally between wells in an apparent smooth way, and/or vertically within a zone as an upward increase or decrease in proportions. Seismic attributes or lineaments may represent important guidelines in evaluating such relations.

5.1.5.1 Trends in Facies Proportions

To evaluate trends in facies proportions, some means of quantifying those proportions is required. A simple technique for facies proportion analysis is based on calculating the zonal average of an index log. The index log is coded as unity in each sample representing the specific facies type and coded as zero elsewhere. The average of an index log will then be equal to the proportion of the facies type within the zone.

By dividing the zone into a sufficiently coarse grid, both horizontal and vertical trend analysis may be performed. Some trial and error may be necessary to find the best scale to be used for estimating trend parameters.

Some guidelines:

- A zone may vary a lot in thickness laterally, ranging from a few metres to several tens of metres. Cross-plots of proportions against the zone or interval thickness are recommended.
- Avoid incorporating zonal averages from wells where parts of a zone interval is faulted.
- Trend evaluation may be impossible if the interval thickness is close to the facies body thicknesses.

5.2 Facies Modelling Methods

Turning a set of logs, 2D maps and a conceptual model into a visual representation that can be viewed in 3D is the pinnacle of their

technical career for many geologists, taking all that they learned in school and university and doing real geology again. However, to achieve a reasonable result that makes both geological and geostatistical sense is a huge challenge and one that should not be undertaken lightly. This overelaborate approach has been termed *hobby geology* by one asset manager I know and is only really appropriate in the academic world. Choosing the right method to distribute facies is an import element in the process, and one that often only comes with experience. The following section briefly summarizes the different techniques available straight out of the 'tool box'; they fall into two categories, pixel- and object-based.

5.2.1 Pixel-Based Methods: Indicator and Gaussian Simulation

Pixel-based models are built using correlation methods based on the variogram, a measure of spatial variation of a property in three orientations, vertical, and maximum and minimum horizontal directions. Experimental variograms can be fitted as spherical, normal (Gaussian) and exponential trends to the input data to produce different outcomes of the facies or property model (Figure 5.6). These 'models' can then be used to distribute a property correlated to trend or a seismic attribute. Indicator simulation is used for discrete properties and Gaussian simulation for continuous properties.

Variogram modelling, whether it is for discrete or continuous properties, is challenging; the following tips may help the selection of a representative solution:

- Decide which domain/scale to analyse and model (e.g. lithofacies or depositional system scale).
- Capture major features that have a geological significance.
- Try to capture the behaviour near the origin (i.e. short-scale variability), especially for continuous properties.
- Look for bad data points and remove them; consider the effect of extreme sample values on the variogram.
- Vertical variograms should be easily estimated from well logs, but look for repeated sequence patterns as well.
- Do not quickly add a large nugget to variogram that seems to lack a correlation feature. Try to reduce the lag distance, then re-calculate variogram.
- For reliable estimation of horizontal variograms, well spacing needs to be smaller than the actual correlation length; in practice, well

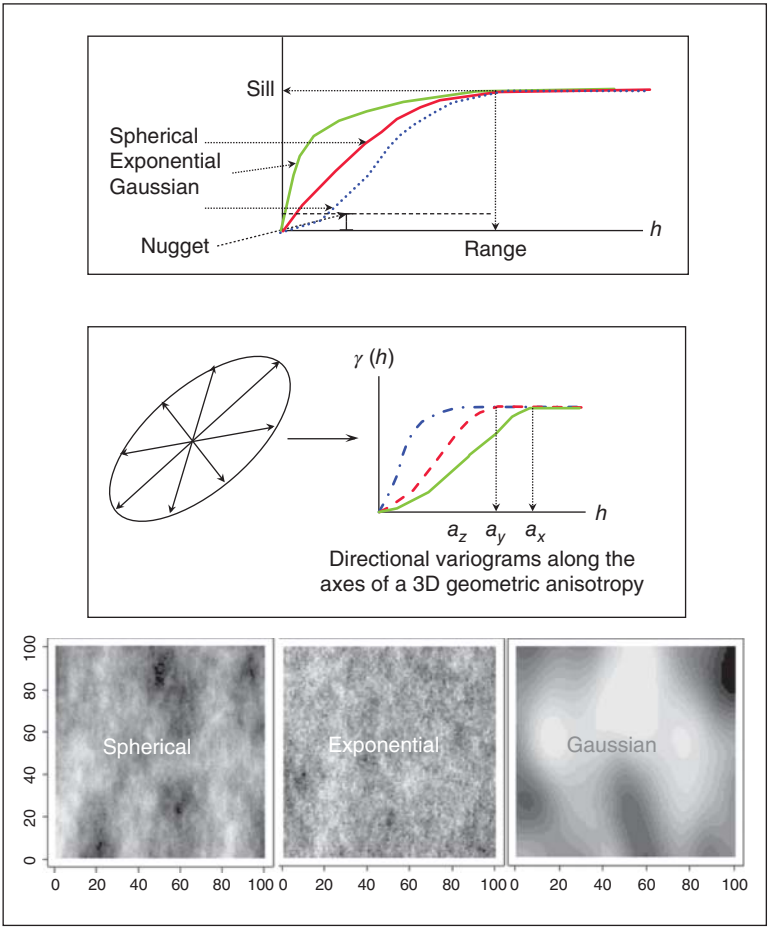


Figure 5.6 *Experimental variograms:* The nomenclature, orientation and application of different variogram types. Reproduced with permission of Emerson-Roxar.

spacing is rarely close enough for a reliable estimation. This is why a good understanding of the depositional system, analogue fields or seismic attributes is needed to infer horizontal variograms.

5.2.1.1 Indicator Simulation (Figure 5.7)

In most geological settings, rock properties can be grouped into populations that are genetically related. These genetic (depositional) units have geometries and are, themselves, spatially correlated. Indicator

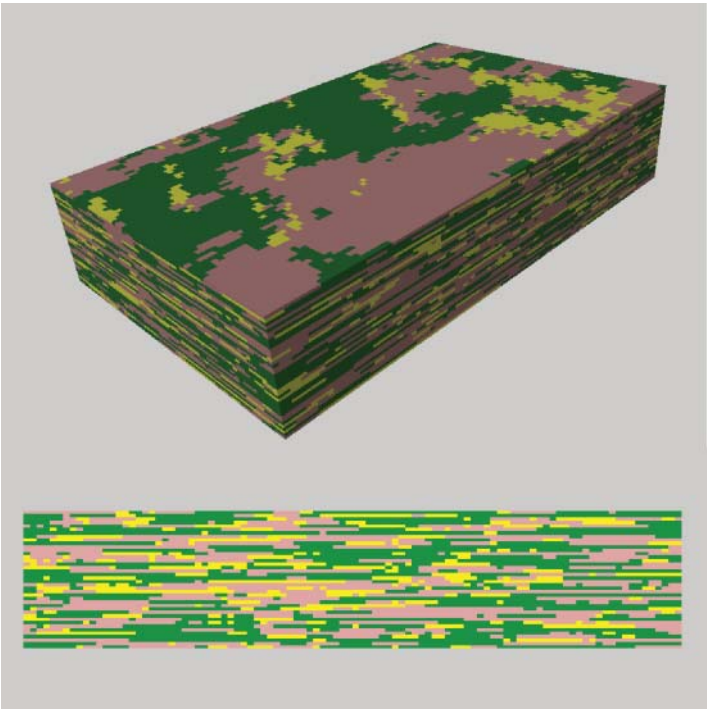


Figure 5.7 Example of an indicator model of an alluvial floodplain comprising shales (green), overbank deposits (brown) and channel sands (yellow). Note that the channel sands are not continuous across the model.

simulation methodologies utilize simple kriging to estimate the probability of a facies transition utilizing indicator variograms. These methods are most applicable when the density of well information is greater than the average size of facies objects, often requires hundreds of regularly spaced wells. Where a robust relationship exists between a seismic parameter (AI) and facies (sand or shale), indicator simulation can return a realistic looking result, but the need to calibrate the model is essential.

In sequential indicator simulation (SIS), an indicator variable (discrete) is selected from a pre-conditioned distribution of values to represent a proportion of a given facies. Indicator simulation is easy to use, but the variogram can be difficult to interpret (model). It is a flexible and data-driven modelling tool; however, the results are inexact; it does not reproduce the variogram or histogram exactly

and does not give a very geological looking outcome. Sequential simulation techniques explicitly calculate the conditional distribution at each point; the user then samples from this distribution.

Sequential Gaussian simulation is used to distribute continuous variables and will be discussed in more detail in the next chapter; a special case of Gaussian simulation used for facies modelling is discussed below.

5.2.1.2 Truncated Gaussian Simulation (Figure 5.8)

Pixel-based methods for modelling transitional facies are based on Gaussian fields and implement a truncated Gaussian simulation (TGSim) algorithm. This method applies a Gaussian field, that is, a

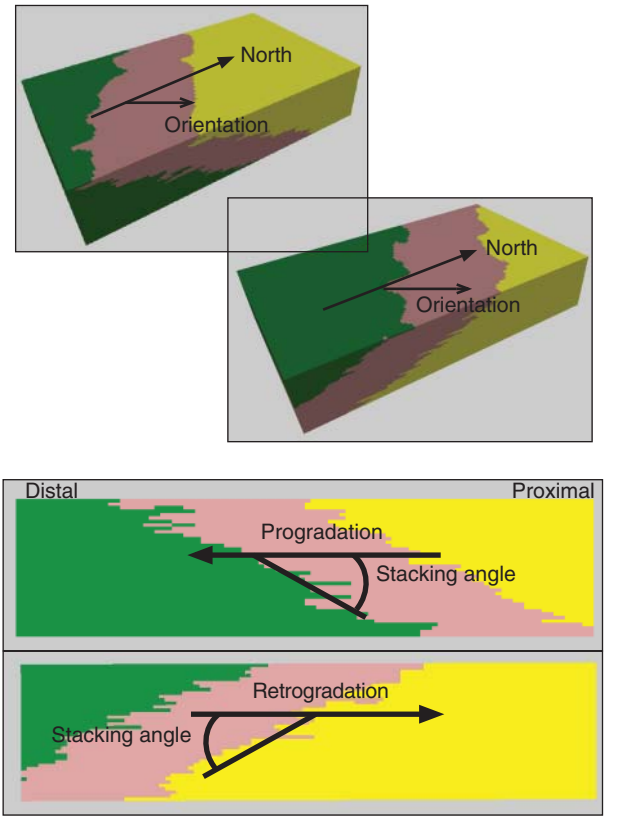


Figure 5.8 Examples of truncated Gaussian simulation using trends model progradation and retrogradation of shallow marine environments.

continuous field, and thereafter truncates it into discrete facies. This implies that the gridding technique (direction, vertical grid set-up) is important for the result.

TGSim requires a strict sequential set-up of facies: If 3 facies are present (*A*, *B*, *C*), then facies *A* must be next to facies *B*, and facies *B* must be next to facies *C*. A conditioning point (a well) that has facies *A* next to facies *C* will not be accepted by the algorithm. It is important to establish a good input or 'prior' trend in TGSim that can then be tested against the results. TGSim is best used to model large-scale features such as progradational or retrogradational packages. In carbonate reefs, TGSim can be used to model the transition from reef core to margin.

5.2.2 Object-Based Methods

Object or Boolean modelling is an alternative method commonly found in the software products. There are generally two object-based methods for modelling: one is focused on fluvial reservoirs, whereas the other is a more general method that can model a wide range of flow-unit shapes (Figure 5.9). One key attribute of object modelling is that it implicitly models connectivity of the bodies leading to an improved recovery factor in the dynamic model; indicator simulation cannot do this normally resulting in lower recovery.

These object-modelling methods do not use the geological grid in the simulation but are sampled into that grid afterwards. The modelling tools apply a 'simulated annealing' algorithm that is an iterative method that gradually conditions on wells, volume fractions, trends and so on. The commonest algorithm is known as General Marked Point Processing (GMPP); this takes the geometric information of a body (thickness/length and width) and by sampling from a distribution of these values inserts bodies into the modelling space at the wells and then extends the object following other specific rules of erosion, repulsion or attraction. The process will also insert objects into the model if a specific facies proportion is to be achieved. The algorithm has the possibility of not converging, which will give a useless result or no result, often crashing the workstation!

Object-based modelling allows the user to build realistic representations of large-scale geological units such as channels, lobes, dunes, sand bars and reefs. Understanding the shape and size of these bodies requires analogue information gathered from outcrop or published literature; many companies have internal databases containing this

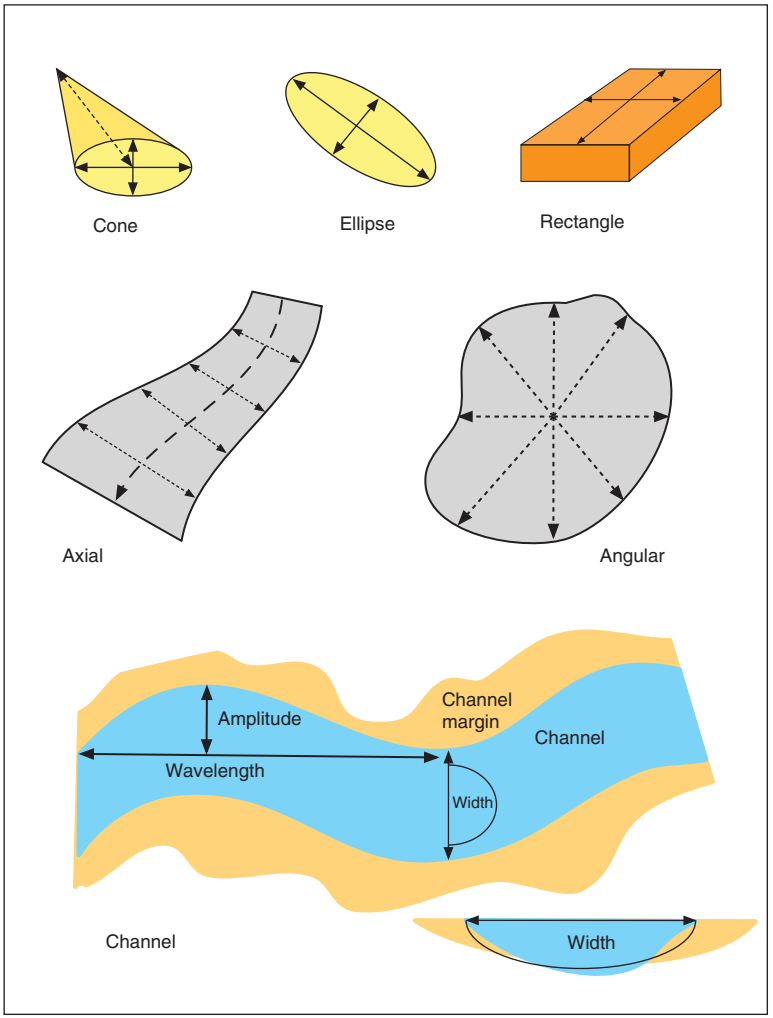


Figure 5.9 Examples of different object shapes that can be modelled to represent facies.

information (Figure 5.10). When modelling specific objects, it is even more important to get the grid cell dimensions correct; there is no point in try to model channels 50–100 m wide if the lateral cell size is 200 m. In object-based methods, one facies is regarded as background facies. This facies will not have any particular shape. Usually, the facies

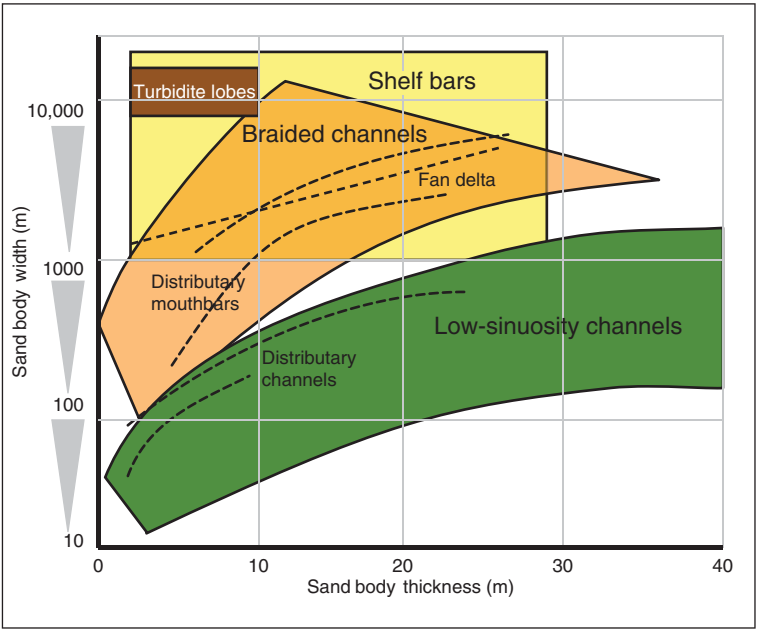


Figure 5.10 Sand body width-to-thickness measurements classified by depositional environment: data compiled from numerous outcrop sources.

that has the greatest proportion from well data is set as background; however, other 3D volumes/models can be used to form a composite model. The algorithm works best if the fraction of background facies is 'large' (say, more than 30%); otherwise, it may be difficult to achieve convergence.

5.2.3 Multi-Point Statistical Methods

Recognizing the limitations in traditional variogram modelling of depositional environments, researchers have introduced multi-point (MPS) geostatistical tools that require a training image to condition the results. Multi-point geostatistics is an algorithm that complements the traditional, variogram-driven, cell-based and object modelling approaches to facies modelling. It is somewhere between the two, being a cell-based approach, but because it uses estimates of the multivariate distribution instead of the simple bivariate distributions that are available to variogram-driven algorithms, it is capable of capturing geometries that are more similar to those available with object

modelling (Daly and Caers, 2010). The need to draw the conceptual model becomes even more critical to utilize this methodology; my preference is to use objects where possible!

5.2.4 Conditioning to a Seismic Parameter

Conditioning facies to seismic can be done within either modelling algorithm, including MPS methods. However, using seismic to condition can be challenging and is very dependent on establishing a robust relationship between a property to be modelled and the seismic parameter. The workflow includes the following:

- Rescaling the seismic cube into the structural model.
- Blocking wells.
- Estimating the 'seismic' factor (so-called *G-function*) that makes a correlation between the seismic property (e.g. impedance) and facies (e.g. channel belts).

The relevant software manuals will give the necessary means to establishing G-functions.

5.2.5 Conditioning to Dynamic Data

At present, no validated method exists for upscaling log data conditioned on well test data. However, there are a number of qualitative and semi-quantitative tools that can be used to help in conditioning:

- PLT (production log data): simple spinner data which indicate intervals of major dynamic contribution to flow.
- RFT/FMT pressure data can indicate differential depletion or pressure communication between reservoir bodies.
- Tracer data and interference tests can indicate inter-well communication.

Dynamic data are currently only used as quality control method, further matching between the static grid data and the dynamic well test data should be performed as part of a history match with the simulation model.

5.3 Facies Modelling Workflows

Typically, the reservoir modeller is trying to represent one of the following depositional environments:

- Aeolian
- Alluvial
- Fluvial
- Deltaic
- Shallow marine
- Turbidite systems
- Carbonate shoal, ramp or platform

There is no standard approach to building a model of any of these environments because each field is unique and so requires a bespoke solution. However, a few simple rules of thumb might be applied based on the 'keep it simple' principle.

1) What is the non-reservoir facies? Which facies do not contribute to storage volume or flow in the reservoir? These facies can be grouped together and if they form a sufficiently large proportion (>40%) can be set to represent the background.
2) Do the remaining reservoir facies show sufficient property variation (porosity/permeability) to warrant modelling them as separate facies? If so, can you identify the facies that either has the greatest potential storage volume or impact on flow in the reservoir? How are these facies connected?
3) How are the facies organized within the sequence hierarchy? Can you predict the relationships between what flows and what doesn't? Is this reflected in way the model zones are constructed and the wells correlated?
4) Do you have sufficient well information to correctly distribute the facies in the geocellular grid? What trends can be recognized in the data?
5) Which facies modelling tools should be used to reflect these conclusions? Can you predict the lateral relationships and scales of the facies? What are the main uncertainties in facies distribution that need to be captured?
6) Do the modelling results return the facies proportions you expect? Is the connected volume of sand sufficient to give the required in-place hydrocarbons? Does the facies model look right?

A very simple approach to modelling a fluvial floodplain might be to recognize three dominant facies: floodplain shale (45%), overbank sands (35%) and channel sands (15%); minor facies such as coals (<5%) could be included as deterministic field-wide layer boundaries (Figure 5.11). Of these facies, only the two sands, overbank

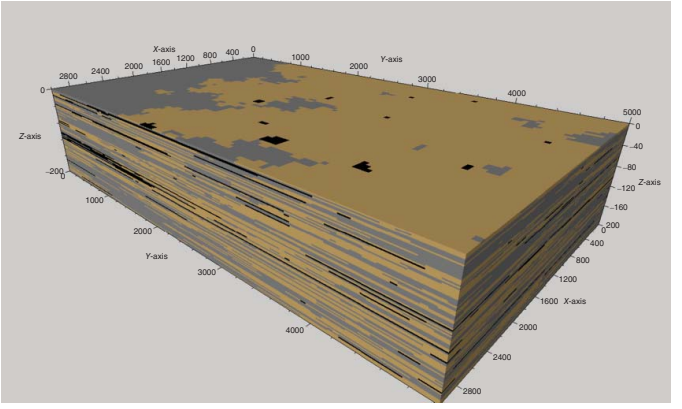


Figure 5.11 An indicator simulation model of a floodplain environment with three facies: shale, overbank and extensive coal deposits.

(porosity-10–20%) and channel (18–25%), contribute to net volume and flow in the reservoir (steps 1 and 2).

The floodplain shale is the background because of the higher proportion, but how is it distributed? Are the overbank deposits attached to the channel as a levee or part of the floodplain mosaic? Are we dealing with a series of stacked fluvial packages in a single grid or have we built a multi-zone grid using the coal layers defining the boundaries? Let us say we have reservoir pressure evidence that leads us to believe that the coals form vertical seals and we can model each system as a single depositional package (step 3).

The relationship between the channel sands and the overbank deposits may be interpreted from well data using both logs and core information (step 4). The simple solution would be to say that the overbank sand is attached to the channel, allowing us to model both facies using object modelling (step 5). To do this, we need to understand the geometry of the channel, its width, thickness, wavelength and amplitude and orientation, and also how wide the levee is in relation to the width of the channel.

An alternative solution would be to model the floodplain as shale, overbank sand and coal using an indicator solution (step 5). The way the facies are distributed would depend on the experimental variogram developed from the well data and using vertical proportion curve data. The shale and coal deposits would have large variogram ranges in both lateral directions, whereas the overbank sand should have smaller ranges with a particular orientation associated with the channel direction. This model would then form a background volume into which the channel object can be modelled with the same geometry information as in the previous example.

Finally (step 6), check the returned facies proportions and connected volumes to see whether the result is what you expect and that visually the model looks like your hand-drawn sketch of the conceptual model (Figure 5.12).

After building this simple model, it may be necessary to further refine the model, especially within the components of the channel body: there may be a cemented base to the channel or a high-permeability zone that needs to be captured. Where identified, these additional facies or 'rock types' can be modelled using deterministic or stochastic methods depending on your understanding of their distribution. Bear in mind, however, that the reservoir engineer may require additional property information from the

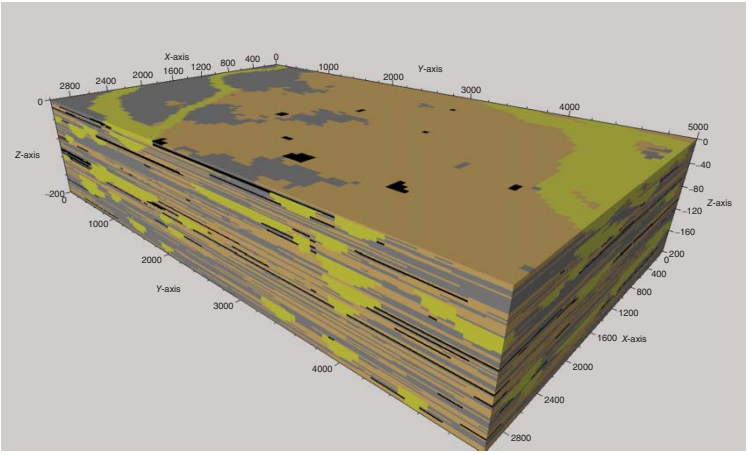


Figure 5.12 The same floodplain model used as a background in which low sinuosity channels are modelled as objects.

modeller or petrophysicist to capture the extra detail in a simulation model.

5.4 Flow Zones

A flow zone is a mappable unit of a reservoir having consistent geological and petrophysical parameters affecting fluid flow (Figure 5.13). The properties of a flow zone should be predictably different from other reservoir rock volumes. In essence, the way in which a reservoir is zoned for modelling could lead to defined flow zones; however, this is likely to produce simplified layer-cake models. A hydraulic flow zone is a dynamic version of the geological flow zone that introduces the concept of the representative elementary volume (REV) (Bear, 1972) that recognizes the scale of flow from the capillary to the sequence (zone) (Figure 5.14).

To a geologist, a flow zone is a definable facies object such as a fluvial channel or shallow marine sandbar; to a petrophysicist, it is correlatable zone with similar porosity, permeability and net-to-gross ratio; to a reservoir engineers, it is a layer in the reservoir that has a consistent dynamic response in the simulator; to a reservoir modeller it is all of these things.

Recognizing a flow zone is a function of the petrophysical properties as much as the geology and is tied up in a discussion of rock types that is best left to the Chapter 6.

5.5 Uncertainty

If the geological analysis has been carried out thoroughly, then there should be little uncertainty in the facies model. However, there are always the unknowns, commonly the direction of channels or proportion of net- and non-net facies. The well data should drive these inputs to the model but seldom is there a wholly conclusive set of data. Any attempt to introduce a trend that is not represented by the wells or seismic means that the model will diverge from the input data, making the comparison difficult.

The solution is to model a number of scenarios that represent the possible solution: model channels that flow in two or three directions across a structure to see what impact there is on net rock volume (NRV) for instance.

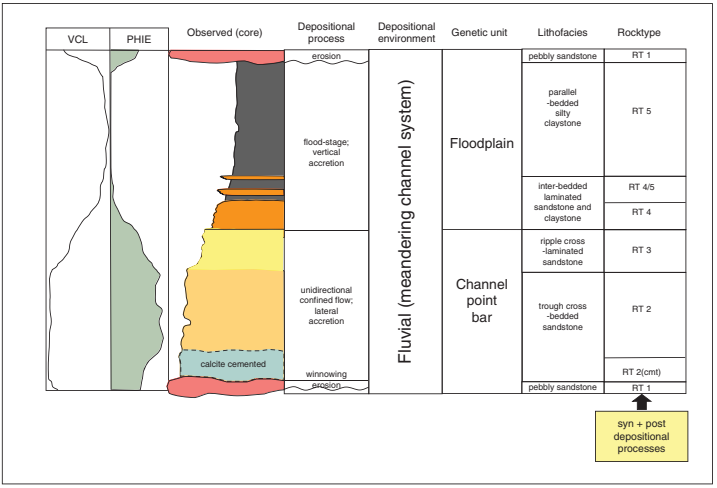


Figure 5.13 Flow zones and rock types, an alternative way to describe the reservoir architecture before property modelling.

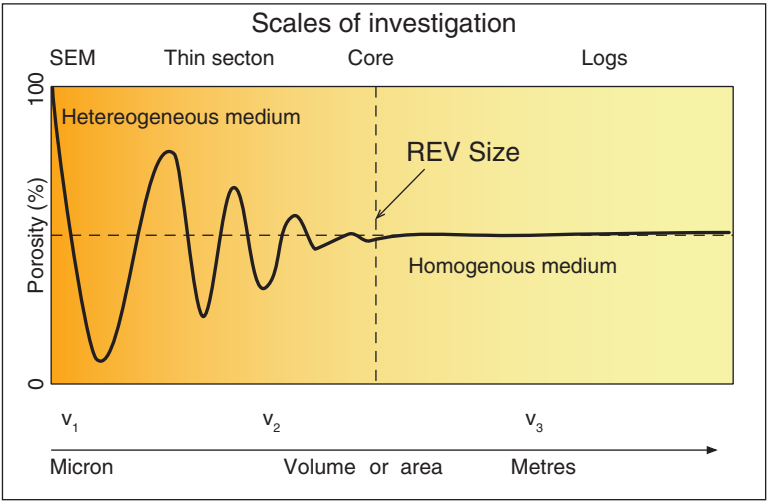


Figure 5.14 The representative elementary volume (REV) concept and scales of investigation and measurement in heterogeneous and homogenous media. *Source:* Bear (1972).

5.6 Summary

Facies modelling is fun providing you have a conceptual model supported by sufficient core and wireline log data. The modelling tools available in the different software products will permit you to represent the geology of the reservoir in an effective way. Trying to replicate the subsurface cell-for-cell is never an option.

6

Property Model

The primary purpose of a 3D property model is to improve the understanding of hydrocarbon distribution for volumetric analysis. A facies-constrained property model tries to capture the heterogeneity in the reservoir in such a way that the dynamics of fluid flow can be modelled more realistically. Generally, 2D maps of reservoir properties are smooth interpolations of the inter-well value, but we know that the subsurface geology is not smooth. The introduction of 3D property modelling means that the vertical variation in properties is preserved and used to populate the inter-well volume using simple geostatistical methods such as kriging. Other trends, such as simple porosity depth relationships or saturation height functions, can also be superimposed on the model.

Grain size distribution, primary depositional process and post-depositional processes such as compaction, diagenesis and fracturing control reservoir rock properties (Figure 6.1). There are two main sources of rock property data: wireline logs and cores; however, both are cursed with issues of sampling volume and bias, data acquisition, interpretation and integration. Successful property modelling depends on the analysis of sufficient representative data and is best done by a geologist and a petrophysicist together. The main objective is to establish correspondence between points where we have exact information (hard data) and points where we have some degree of guidance (soft data) and then define extrapolation parameters to distribute the data. Hence, the analysis relies heavily on statistical and geostatistical treatments.

Working as a development geologist, I have never had more than five wells in the available data set; this can no way be seen as a statistically meaningful sample of reservoir properties throughout the field. This forces the modeller to take liberties with the data that may seem

Reservoir Modelling: A Practical Guide, First Edition. Steve Cannon.

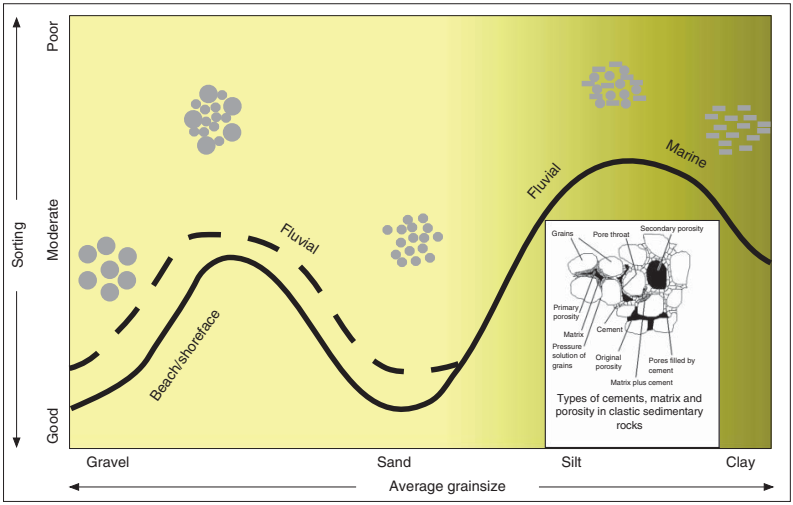


Figure 6.1 Grain size and sorting of sediments in different depositional environments. *Source*: Folk (1980). Copyright 1980, Hemphill Publishing.

a little cavalier, but as we are only trying to estimate the hydrocarbon distribution and in-place volume, a stochastic approach allows for an estimate of the uncertainty in our results. Once a field has gone into production, usually a more comprehensive data set is available and the geostatistics has a better chance of reducing the uncertainty.

In property modelling, we are basically distributing the results of a petrophysical interpretation based on indirect measurement of physical responses of rock and fluid.

What are we trying to measure?

- *Porosity*: total or effective, primary, secondary
- *Saturation*: hydrocarbon, water, irreducible
- *Permeability*: absolute, effective, relative, moveable fluids
- *Lithology*: sand, shale, limestone, dolomite

What measurements do we make?

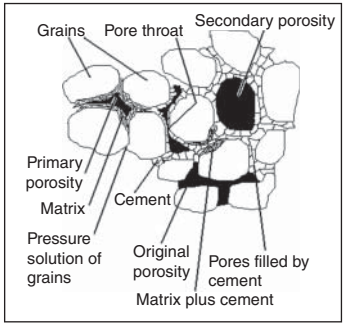
- *Density*: rock and fluids
- *Acoustic*: rock and fluids
- *Resistivity*: rock and fluids
- *Nuclear*: rock and fluids

None of the measurements are direct; they all are indirect values based on the interpretation of a physical response to a static property or some source of stimulation. The measurements must be calibrated by core analysis data, which is a direct, if imperfect, measurement, before they can be used for estimation of the desired property we hope to model.

6.1 Rock and Fluid Properties

6.1.1 Porosity

Porosity is defined as the capacity of a rock to store fluids and estimated as the ratio of the pore volume to the bulk volume. Porosity is a non-dimensional parameter expressed as a fraction or a percentage (Figure 6.2a). The porosity of a rock comprises two main elements: primary depositional or intergranular porosity and secondary porosity, which may be the result of grain or particle dissolution or present as microporosity in authigenic clays. Porosity may be defined as *effective* or *total* depending on whether it includes porosity associated with



Porosity = volume of pore space / total volume of rock

Expressed as a fraction or percentage

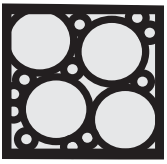
A function of grain size and packing

Can be expressed as TOTAL or EFFECTIVE

Primary porosity reduces with compaction due to burial and lithification/cementation

Secondary porosity is a result of disolution of unstable minerals

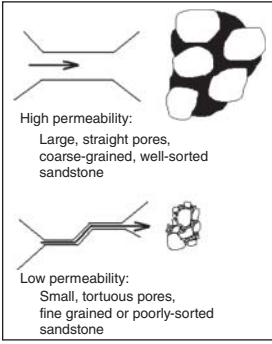
(a)



Water saturation (S_w) = pore volume filled with water / total pore volume

Hydrocarbon saturaon (S_h) = (1 – S_w)
Can be expressed as TOTAL or EFFECTIVE property dependent Be consistent in use of terms

(b)



Measure of the ability of a reservoir to conduct fluids A dynamic property dependent on rock and fluid characteristics with a directional (vector) component May be a predictable relationship with porosity

$$Q = \frac{kA\Delta p}{\mu L}$$

Absolute, effective and relative permeability values may be required as a key input for dynamic simulation

(c)

Figure 6.2 (a) Porosity: the relationship between volume of pore space and total volume of rock is a function of grain size, sorting and packing at the time of deposition. Post-depositional processes such as compaction and diagenesis can alter the original relationship. (b) Water saturation: the proportion of the total reservoir pore volume filled with water: the remaining pore volume is filled with oil or gas, not necessarily hydrocarbon gas. (c) Permeability: the ability of a reservoir to conduct fluids through an interconnected pore network. *Source*: Cannon (2016). Copyright 2016, John Wiley & Sons.

clays; some tools measure total porosity and must be corrected for the clay content. This is a simple classification that does not include all carbonate rocks or certain clay-rich shale reservoirs. Fractured reservoirs also need to be treated separately, being defined as having a dual porosity system, matrix and fracture.

6.1.2 Water Saturation

Water saturation (S_w) is the proportion of total pore volume occupied by formation water; hydrocarbon saturation is derived from the relationship ($S_h = 1 - S_w$). It may be expressed as a fraction or a percentage depending on how porosity is defined (Figure 6.2b). There is another direct link to porosity terminology, as water saturation can be either a total or effective value. Logs measure both the mobile water and the clay-bound water in the pore space. The terms *irreducible*, *residual*, *connate* and *initial water saturation* are also commonly used, sometimes without due regard to the meaning. Irreducible water saturation (S_{wirr}) is defined as the minimum S_w at high capillary pressure and saturation, as the effective permeability to water approaches zero. The initial water saturation (S_{wi}) is the proportion of water in the reservoir at the time of discovery and may be synonymous with connate water, the water saturation at the time of deposition, if no hydrocarbons are present. In a hydrocarbon-bearing reservoir, S_{wirr} is always less than S_{wi}. The term *transition zone* also has more than one meaning depending on who is using it: to a geologist or a petrophysicist, it is the zone between the lowest level of irreducible water and the free water level (FWL); this is a static definition. To a reservoir engineer, it is an interval in a well that flows both oil or gas and water at the same time: the two 'zones' may be contiguous.

6.1.3 Permeability

Permeability (K or k) is the measure of the capacity of a reservoir to conduct fluids or for flow to take place between the reservoir and a wellbore. Permeability is a dynamic property dependent on the associated rock and fluid properties (Figure 6.2c); it is also one of the most difficult properties to measure and evaluate without data at all relevant scales – core, log and production test. At the microscopic or plug scale, permeability is a function of pore network and whether there are large or small pore throats and whether the connecting pathways are straight or tortuous, a function of grain size and sorting.

Table 6.1 Permeability ranges for different qualitative descriptions of permeability.

Poor	<1 mD	'Tight' for gas
Fair	1–10 mD	'Tight' for oil
Moderate	10–50 mD	
Good	50–250 mD	
Excellent	>250 mD	

Permeability is also a vector property as it may have a directional component, resulting in anisotropy. Permeability may vary greatly between the horizontal and the vertical directions, impacting on the directional flow capacity of a reservoir. Given the difficulties in reliably measuring permeability, a qualitative assessment is often made depending on the hydrocarbon in place (Table 6.1).

Permeability is measured in darcies (D) but usually reported as millidarcies (mD), named after the French water engineer who first attempted to measure the flow of water through a vertical pipe packed with sand. The rate of flow is a function of the area and length of the pipe, the viscosity of the fluid and the pressure differential between the ends of the pipe. This law only applies to a single fluid phase and may be termed *absolute* or *intrinsic* permeability. Effective permeability (K_{eff}) is the permeability of one liquid phase to flow in the presence of another; relative permeability (K_r) is the ratio of effective to absolute permeability for a given saturation of the flowing liquid, that is, permeability of oil in the presence of water (K_{ro}). Permeability is a key input for numerical reservoir simulation.

Relative permeability is the normalized value of effective permeability for a fluid to the absolute permeability of the rock. Relative permeability expresses the relative contribution of each liquid phase to the total flow capacity of the rock.

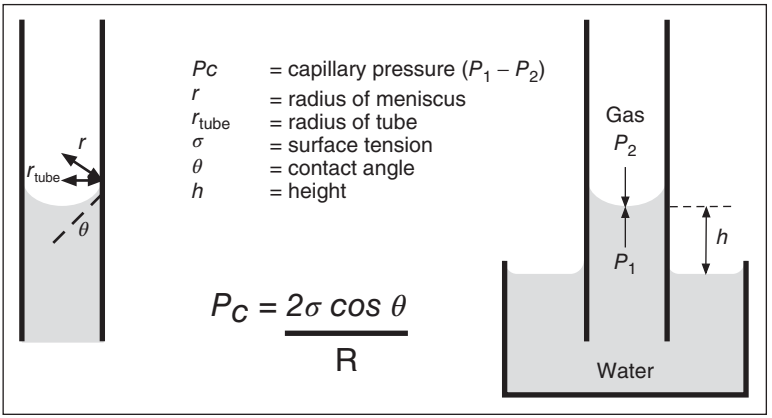
6.1.4 Poro–Perm Relationship

Traditionally, core porosity is plotted against the logarithm of core permeability to give a linear poro–perm relationship, beloved of geologists and petrophysicists. This linear relationship is then used to evaluate reservoir quality (RQI) and distribute permeability in a model. This relationship is at best tentative as permeability is a function of grain size and sorting, which defines the pore throat size

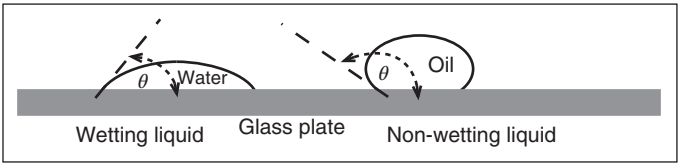
distribution. Wherever possible, the facies model should be used to partition the core data such that a number of poro–perm relationships can be derived that will be used to define heterogeneity.

6.1.5 Capillary Pressure

Capillary pressure acts at a microscopic scale in the reservoir, which in conjunction with viscous and gravitational forces defines how a reservoir performs dynamically. Capillary pressure occurs whenever two immiscible fluids occur in the pore space of a rock and is defined as the pressure difference measurable in the two phases (Figure 6.3a). There is an inherent relationship between capillary pressure and water saturation because water is retained in the pore space by capillary forces. Capillary pressure also determines the fluid distribution and saturation in a reservoir, hence the link to wettability.



(a)



(b)

Figure 6.3 (a): Description of capillary pressure based on a simple experiment of water rising in a tube; (b) description of wettability as the interaction between a surface and an adsorbed fluid. *Source*: Cannon (2016). Copyright 2016, John Wiley & Sons.

6.1.6 Wettability

Wettability is a measure of a rock's propensity to adsorb water or oil molecules onto its surface in the presence of another immiscible fluid. At deposition, a thin film of water is usually formed around the grains leaving the rock water wet, the normal situation; however, carbonate rocks are commonly oil wet or have intermediate wettability. Wettability is a function of the surface tension between the solid grain and the fluid in the pores (Figure 6.3b).

The impact of wettability on other dynamic properties of a rock is important to understand as it controls the fluid saturation and distribution in a reservoir. Although most (clastic) reservoirs would be considered to be water wet, under certain conditions, all reservoirs can become oil wet at least in part. Carbonate reservoirs have a greater tendency for the oil wet state because of the greater adsorption capacity of calcium/magnesium carbonate. Many reservoirs are of mixed wettability, oil wet in the large open pores and water wet in the smaller isolated pores often filled with microporous clays.

6.2 Property Modelling

At its simplest, we are only required to model porosity, water saturation and permeability; the complications arise with understanding the relationships between these properties. Porosity is a static property and should be straightforward if the data are partitioned correctly into facies or zones, and there are a statistically significant number of samples. Permeability is a dynamic property that has traditionally been linked to porosity through a log-linear relationship. Water saturation is a function of pore volume, permeability and height above a datum, the FWL.

Two other topics that need to be discussed are whether we are working in a *total* or *effective* property domain and the use of net-to-gross (NTG) ratio in defining what contributes to volume or flow. Both topics raise the hackles of petrophysicists and reservoir engineers but need to be dealt with in the workflow. The reservoir model should ultimately represent *effective* properties if you need accurate volumetric results, and a robust facies model should negate the need to cut-offs in defining what is *net* reservoir. The total property model (Ringrose, 2008) is a potential solution to the problem if there are sufficient data.

6.2.1 Property Modelling Workflow

1. *Data screening*: Ensure that all anomalous values, data spikes or outliers have been deleted or explained/accounted for before performing any data analysis. This should have all been done in the data collection and interpretation step, but it is often worth double-checking; sometimes, raw data are loaded into the project.
2. *Blocking*: The property data must be upscaled into the grid cells in each of the wells. Visually check that the upscaled data honours the input data by displaying the wells individually and as histograms of all the data. Comparisons of the data mean values and standard deviation for each property should be similar in the input and blocked data. This analysis can be performed on a zone-by-zone basis to determine the difference in the levels of heterogeneity; if the zoning has been done properly, then there should be obvious difference.
3. Review the property data statistics with respect to the facies scheme to ensure that the appropriate level of detail has been captured. It is possible to further refine or simplify the zonation or facies scheme at this time, or even re-grid the model. Be prepared to revise the model design if required at this stage; it is much easier to do it now!
4. Start by trying to understand the spatial relationships in the data by looking for vertical or lateral trends. Can the data be represented by an experimental variogram and does that variogram apply everywhere in the model. Are the data normally distributed and stationary? If not, then you will need to transform the input data before moving to the next step.
5. Decide which property modelling method is appropriate for your data; many different algorithms are available in the toolbox. Start with a deterministic method to test whether the data can give some indication of specific trends; the available data will define what approach is feasible. Limit yourself to porosity modelling at this time; it is the easiest property to understand and drives most of the other relationships.
6. Evaluate the initial results by comparing the blocked input data statistics with the model results by facies and zones. Mean and standard deviation values in both data sets should be similar unless some external data trend has been applied. Always be prepared to defend the outcomes that do not match the raw data; keep a record of any trends that, if applied, change the outcome.

6.2.2 Data Preparation

This section describes how shoulder effects, calcites and noise can be removed from log data used in the data analysis.

6.2.2.1 Shoulder Effects

In log data, any sharp boundary will appear transitional due to the response from the logging tool and this is named the shoulder effect. The logging tool will be influenced by properties on both sides of any discontinuity. Such response may be enhanced a lot if the recorded signal is sampled sufficiently and properly post-processed to minimize such effects (i.e. normally involving some kind of deconvolution of a regularly sampled log). A more brutal way of avoiding shoulder effects is simply to remove observation within a certain distance from the boundaries (in general, at all facies and zone boundaries) (Figure 6.4).

What is the problem with shoulder effects? When analysing petrophysical data sorted on facies types, a large amount of the observations may represent samples influenced by shoulder effects. In the worst case, such shoulders may change the estimated expected values for the facies, leading to under or overestimates of available resources. Such shoulders may also lead to too wide univariate distributions in petrophysical properties, which, dependent on the imposed heterogeneity structure (variogram model), may have severe impact on the resulting flow properties.

It is recommended to improve processing routines for generating composite logs and CPI logs in such a way that shoulder effects are minimized. It is possible to trim the minimum and maximum input values as part of the data analysis process before transformation.

6.2.2.2 Filtering of Spikes in Log Data

Spikes may occur randomly in log data. They are common at points where different logging runs are linked together. If they are not removed in advance, they may represent severe outliers destroying both analysis estimates and observations used as modelling constraints. Visualization of cross-plots, histograms, min/max statistics and so on will highlight problems related to spikes. Hopefully, this type of artefact will have been removed in the initial CPI construction.

6.2.2.3 Filtering of Carbonate Nodules

In clastic reservoirs, carbonate spikes are normally related to nodules or bands formed from the alteration of shelly debris concentrated in

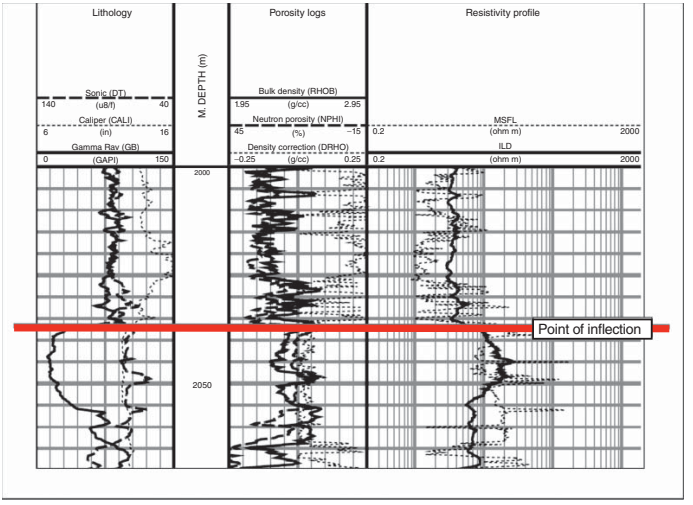


Figure 6.4 Identify the point of inflection for a suite of wireline logs to determine bed boundaries and eliminate the 'shoulder effects'; part of the blocking of continuous raw log data. *Source*: Cannon (2016). Copyright 2016, John Wiley & Sons.

shallow marine environments. They are best handled as non-reservoir intervals but should be recognized as a significant proportion in some fields acting as baffles to flow. Dealing with carbonates in this context is discussed in Section 5.1.2, as well as in the discussion of net-gross.

6.2.3 Blocking or Upscaling Well Data

A 1 m-thick cell at the well will comprise a single facies but will need to capture around six (log sample interval 15 cm) porosity values that might all be from the same rock type or from more than one distribution. How we average this will depend on the property being upscaled; any number of methods are available in the toolbox. The use of 'most of' or the 'histogram' method that worked for a discrete property like facies will not work for continuous variables.

There is obviously a link between the scale and the type of heterogeneity. If cells of $50 \times 50 \times 2$ m successfully model geology, it is an underlying assumption that we are modelling on a scale represented by this volume. The data needed for such modelling should, in theory, be scaled to be representative for the geo-modelling scale. A simplified solution used in this context is to use some kind of an average of the samples.

Porosity is a relatively simple property to upscale; it is static, dimensionless and volume related, so a simple arithmetic average will work. The results may be averaged biased to the facies by a weighting approach; this has the effect of smoothing the outcome for all the cells in the well but gives a more representative range for a given facies. Non-net values should be 'undefined' and not zero if NTG is to be modelled: shale porosity should be included in the continuous porosity if the facies is to be used to define net and non-net rock. In this way, a pseudo-NTG is generated for each cell that reflects a lower average porosity honouring the non-net volume. It may be appropriate to block well data on a zonal basis to allow you to change the method in each zone.

A log-derived water saturation property in a well is another continuous property that is a function of the pore volume. It is an additive property that can be upscaled using a summation approach like porosity; it should not be biased to the facies log. The only reason to upscale water saturation is to compare the log-derived results with the subsequent saturation height calculation.

Before attempting to upscale permeability, find out how the log was generated: commonly, it will be a log-linear relationship with

porosity derived from core data. However, unless you have discussed a multi-facies relationship, the results may not be appropriate for use with a facies model. One observation commonly made is that permeability prediction using a simple relationship almost always underestimates the high permeability values and overestimates the lower end. There are a number of methods for blocking permeability and the default is usually a geometric average, but depending on the heterogeneity of the data, an arithmetic or harmonic mean may be equally valid: try the different methods available and compare the results to ensure that the extremes are captured. Permeability is a dynamic property, so involve the reservoir engineer at this stage.

Alternative grids representing different scales may be useful simply for analysing purposes. Coarser grids may be used for defining trends in the Gaussian modelling or trends in facies proportions and so on. Note that the average cell size to be used in 3D modelling should be representative for the data used in the analyses of model parameters (variogram analysis, correlation coefficient estimates, etc.). We may end up with a complex hierarchical set of scales used for analysis purposes, and it is important to understand the relationships between the scales.

It is important to QC the results of the blocking process by comparing the petrophysicists' input data and upscaled output data. This is done by comparing sums, averages and standard deviation of the two sets of data. This should be done by facies, zone and field area if known trends in the data exist.

6.3 Property Modelling Methods

There are several ways to model reservoir properties: Figure 6.5 shows three examples where the same well control is used to model porosity. The first picture demonstrates the results generated using a 2D mapping algorithm. The second picture shows the 3D interpolation technique, and the third shows a stochastic technique to model porosity. All three models will have different outcomes when calculating volumes, well planning or dynamic simulation. You must be careful selecting the property modelling technique.

6.3.1 Deterministic Methods

In cases where a simple or quick model is required, advanced techniques such as stochastic petrophysical modelling may not

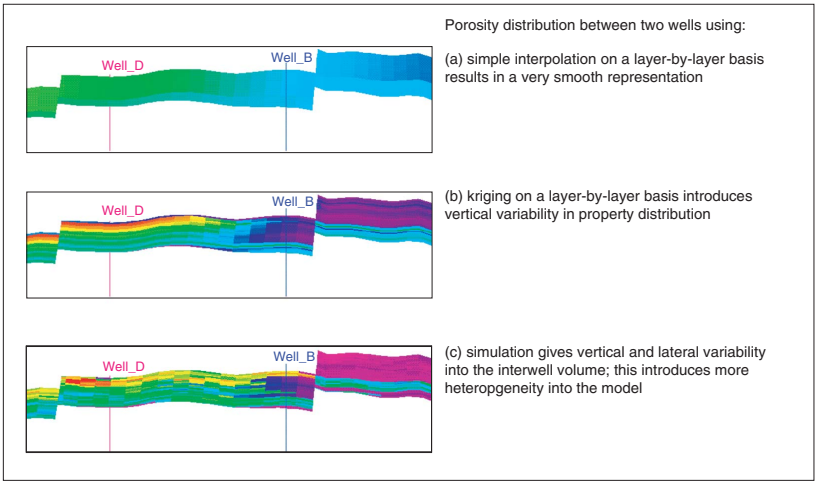


Figure 6.5 Porosity distribution: mapped, interpolated and stochastically distributed showing the increasing degree of heterogeneity in the property. *Source*: Cannon (2016). Copyright 2016, John Wiley & Sons.

be appropriate. In these situations, a wide range of deterministic modelling methods may be applied to create a property model:

Constant value: This can be biased to a facies model. For example, the porosity in channels is 22% and in the crevasse splays it is 18%.

Function: Simple 1D functions are used to model properties; for example, J-functions are used to model water saturation. Functions can be used as a trend in combination with other modelling techniques, such as compaction curves.

2D maps: Maps are often used as input for 3D models. These maps can be used as trends together with other modelling techniques. The maps can be used to calculate quick-look volumetrics. Note that facies information is not very visible in the maps and that 'bulls-eyes' predict where the wells are.

Interpolation: A simple, crude method that has only one possible result (realisation). The routine has the following steps: (i) An interpolation ellipsoid of user-specified size is drawn around the cell to be assigned a value and all already populated cells that lie within the ellipsoid are noted. (ii) An inverse distance weighted average of those cells is taken and assigned to the cell in question. (iii) Another unpopulated cell is then chosen at random and the same process is carried out. (iv) The above steps are followed until all the cells within the grid have been assigned a value.

As an inverse distance weighted average of other cell values is taken, a very smooth model is produced with the values at one well grading smoothly into the values at another well. This is obviously very unrealistic and should therefore only be used to give you an approximate figure for your volumes and so on. Interpolation destroys the statistics of the original data and does not capture the extremes of a property.

6.3.2 Statistical Methods

Geostatistical property modelling allows more control on the spatial statistics of the model and also allows for smaller scale heterogeneity to be captured. Here, an understanding of the uncertainty is required or where strong trends are present in the data. This approach gives the user the possibility of generating multiple outcomes in a similar way to stochastic facies modelling. In all cases, the input data must be normally distributed and any trends removed; this is usually performed in a data analysis module that is part of the property model software.

There are two main types of geostatistical methods:

Kriging is an estimation technique that uses interpolation based on a weighted average of the existing data. A variogram is used to calculate those weights; kriging has the ability to incorporate anisotropy as part of the weighting process. Another advantage of the kriging method is that it automatically declusters the data. Kriging creates smooth transitions from one point to the next; it does not replicate the variability that may exist at scales smaller than the space between the data points. Kriging estimation is always the expected value at the point; the variance at a point is never utilized.

The challenge faced by the modeller is to estimate the experimental variogram; it is necessary to define the variogram in three directions and to identify the nugget, sill and lag distance that describe the shape of each variogram (Figure 6.6). This is no easy task and requires sufficient input data of high quality. Fortunately, porosity, constrained by facies, is a relatively benign property, but it cannot be stressed enough that the quality of results depends on the preparation of the input data for analysis.

One property of kriging that sets it apart from other interpolation methods is that it minimizes the estimation error inherent in all statistical methods; the tendency to underestimate the error is the same as to overestimate it. The mathematics of kriging is at the heart of many simulation methodologies forming one of the foundations of geostatistics.

Most geostatistical software packages will have a number of different methods based on kriging in the toolbox such as

- simple and ordinary kriging
- kriging with a drift
- co-kriging

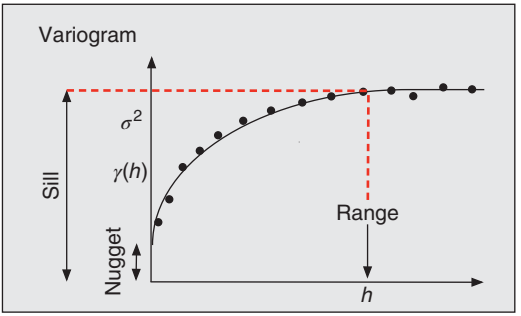


Figure 6.6 Schematic of a variogram showing the nugget, sill and range.

Simulation is an alternative method that will avoid the smoothing tendency in the kriging methods. Most simulation algorithms utilize a randomly sampled value from the conditional distribution at a given point to estimate the property. This constrained randomness models the variance at all scales and therefore produces spatial distributions that can vary from realization to realization and yet always honours the data and the variogram. An experimental variogram still needs to be defined for any of the simulation methods.

Simulation does a much better job, visually, of representing the actual data than the kriged estimates (Figure 6.7); it honours the variogram, indicating that the information regarding spatial variance has been captured. As a result of honouring the spatial variance model, the distribution of values in the realization also matches the distribution of the input data; kriging does not honour that distribution.

Some methods commonly used for property modelling based on simulation are as follows:

- Sequential Gaussian simulation
- Sequential Gaussian simulation with external drift

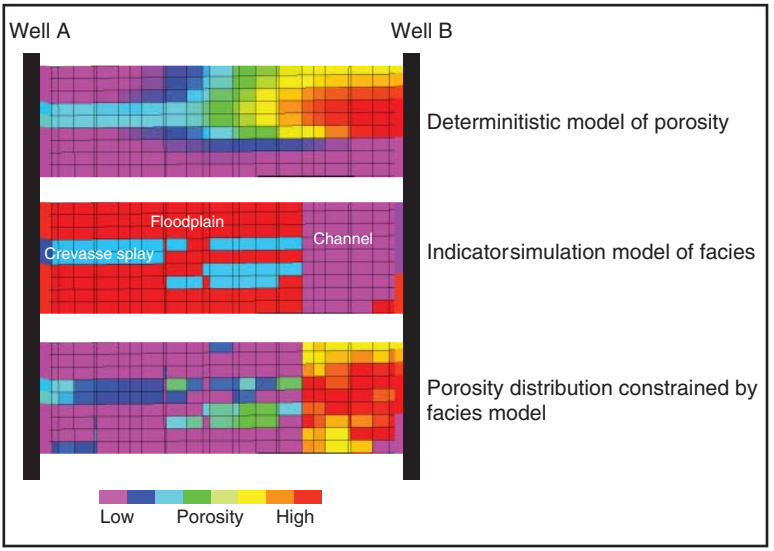


Figure 6.7 Examples of porosity distribution by kriging and simulation showing the greater variability in distribution away from well control in the latter realizations. *Source*: Reproduced with permission of Emerson-Roxar.

- Sequential co-located co-simulation
- Gaussian random function simulation

Simulation and kriging conserve the spatial statistics in three directions (most importantly, the vertical heterogeneity in permeability) as seen in the sample values, whereas in interpolation, this variation is not taken into account – the variogram for interpolation would look like a straight line rather than a curve. Simulation captures the extremes of permeability and directional variability, whereas kriging only captures the directional variability, interpolation does neither. Ultimately, it is the degree of variability (heterogeneity) in permeability that controls fluid flow through a reservoir. Breakthrough time for a simulated model will be far more accurate than from an interpolated model.

6.3.3 Modelling Porosity

Porosity is probably the easiest property to model; the process often starts by binning the porosity values into facies classes (Figure 6.8). The boundaries of the porosity distribution are well defined. Trends, such as compaction or diagenetic influences, are easily determined by plotting porosity against depth. A simple transformation sequence can be applied to achieve a normalized distribution. The following steps describe the process for porosity modelling:

1. A histogram of the distribution of porosity values as seen in the blocked wells is created. It should show a normal distribution between the end-points.
2. Variograms are calculated in three directions based on the data that can be seen in the blocked wells. A variogram is basically a graph of how much values at points at different distances apart are related to one another. These 'experimental variograms' can then be adjusted according to the geologists' understanding of the spatial statistics of the geology.
3. The variograms are used to produce a distribution of possible values at each cell in turn, away from the blocked wells. In kriging, the average of this distribution is taken, whereas the extra step of simulation is to pick a random value from that distribution. As you can imagine, if you have a large number of cells (as you do in most grids), repeated simulation will reproduce the distribution seen in the blocked wells exactly.

Take our facies model described earlier: the floodplain shale may have porosity 0–5%, the overbank deposits 5–15% and the channel

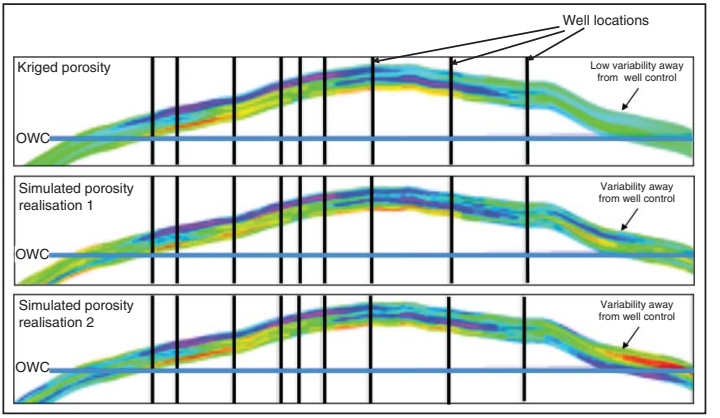


Figure 6.8 Facies-constrained porosity distribution: (a) the interpolated porosity model honours the well data but results in a smooth distribution between the wells; (b) and (c) a simple threefold facies scheme of channel, overbank and floodplain allows the porosity seen in the well to be distributed more meaningfully, capturing the rapid changes laterally in the model. *Source*: Reproduced with permission of Emerson-Roxar.

sands 15–25%; in each case, the range is normally distributed and does not display any trends (Figure 6.9). Depending on how the facies model was built will affect the porosity distribution in the property model.

6.3.3.1 Total Versus Effective Porosity

As promised, there now follows a discussion on whether to use a 'total' or 'effective' porosity system in reservoir modelling. Total porosity is the total void space in a volume of rock whether it contributes to fluid flow or not: effective porosity excludes isolated pores and pore volume associated with water adsorbed on clays or other grains, in other words immobile water. Effective porosity is generally less than total porosity, but in clay-free, clean sands, the two properties are likely to be similar (Figure 6.10). Petrophysicists calculate total porosity from wireline data using a number of different methods and calibrate the results with core-derived porosity measurements. After cleaning and drying the core samples, the results returned are somewhere between total and effective porosity, the harsher the cleaning and drying process, the nearer to total porosity. A correction for overburden pressure can be applied to replicate the conditions in the reservoir.

What we are trying to model is the effective porosity in the reservoir at reservoir conditions to correctly estimate the volume of moveable hydrocarbons in the field and a recovery factor. If we use total porosity, we will overestimate the in-place hydrocarbon volume. Discounting the clay-bound water using a volume of shale cut-off derives effective porosity. Ask the petrophysicist to provide this input for each well in the data set, rather than having to calculate it yourself: sometimes, it is easier being the petrophysicist and modeller combined!

6.3.4 Modelling Permeability

Permeability is a dynamic vector property having both value and direction, so anisotropy is commonly modelled both vertically and laterally. Permeability is usually grouped into the same facies classes as porosity but can have a larger variation in values because it is log normally distributed (a skewed distribution) (Figure 6.11). Vertical permeability is often calculated based on the horizontal permeability; most times, a K_v:K_h ratio is used. For each facies group, parameter histograms and cross-plots must be made in order to validate the assumptions. For facies with few samples, one may have to rely on concepts and assumptions regarding how well such properties are correlated. Permeability is important for flow simulation; time is, therefore, needed to analyse the controls on distribution and to model it correctly.

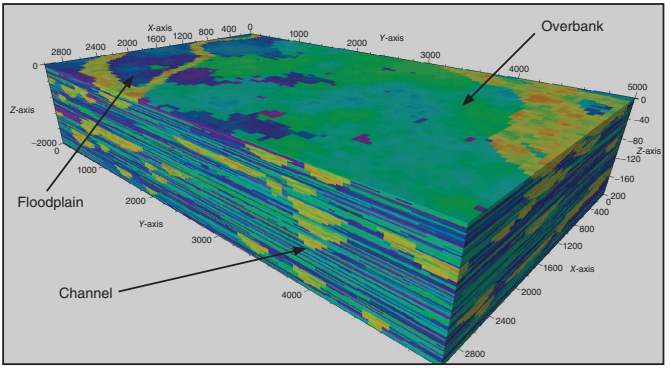


Figure 6.9 Facies-constrained porosity model showing channel, overbank and floodplain distribution.

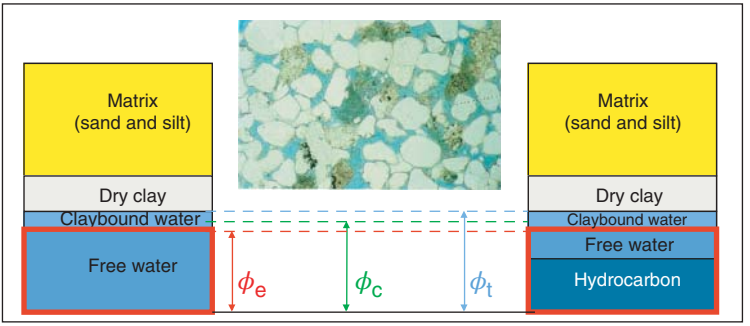


Figure 6.10 Total versus effective porosity systems; log analysis gives total porosity including clay-bound immoveable water. Core analysis may also give total porosity depending on how the plugs have been cleaned and dried. For volumetric estimates, we should use effective properties, so we should model overburden corrected effective porosity. *Source*: Cannon (2016). Copyright 2016, John Wiley & Sons.

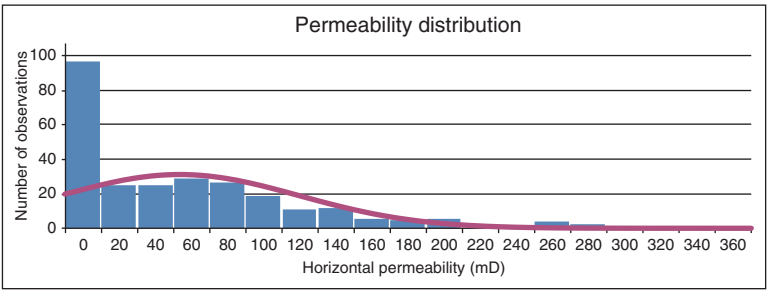


Figure 6.11 An example of a typically skewed permeability distribution with approximately 50% of the observations being <20 mD.

Commonly, permeability will be distributed based on the porosity model by either co-kriging or co-simulation; the linear function relationship is not recommended. In each of these cases, a permeability value is selected from the distribution that corresponds to a given porosity in the cell. The difference in the two methods is that in co-simulation the positioning of the cell is randomly chosen.

6.3.5 Modelling Water Saturation

Water saturation in the reservoir should be modelled using a saturation height function derived from logs and core analysis data

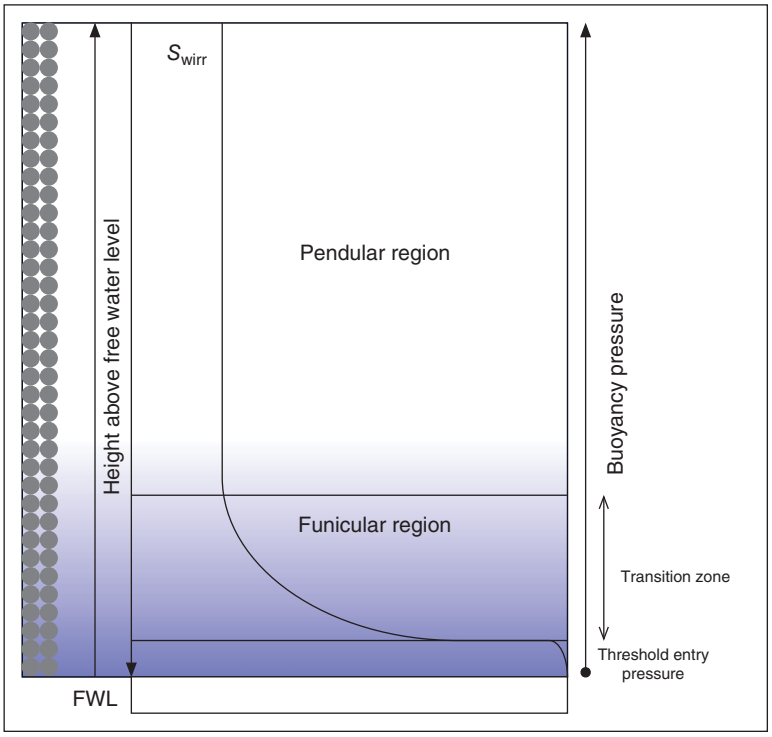


Figure 6.12 Physics of the reservoir; representation of fluid distribution with an oil reservoir based on the relationship between water saturation, capillary pressure and the free water level datum. *Source*: Cannon (2016). Copyright 2016, John Wiley & Sons.

(Figure 6.12). It is *not* recommended to model water saturation using a stochastic petrophysical simulation technique. More often than not, however, a simple layer average constant value is used based on a log-derived average value, and to achieve this, the model becomes a simple layer-cake construction with too many zones. Always check what water saturation you are being given to model: total, effective, initial or irreducible?

A better alternative is to use a saturation height relationship derived from logs based on the capillary pressure and the density difference between the two fluids. There are a number of ways to model water saturation based on the physical principle of how a reservoir, initially filled with water, is 'drained' as the hydrocarbons fill the trap displacing the water. In this case, it is necessary to establish the FWL at which

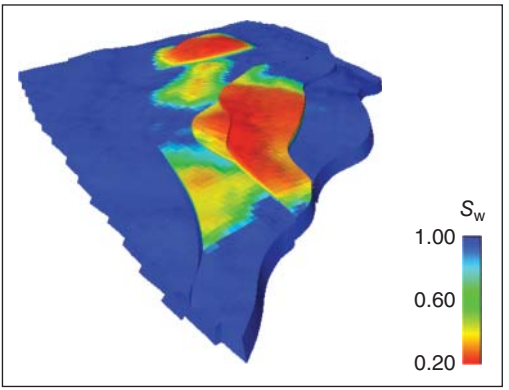


Figure 6.13 Example of a water saturation model using a saturation height relationship; the free water level is identified where $S_w = 1$. *Source*: Reproduced with permission of Emerson-Roxar.

water saturation is 100% and capillary pressure is zero: this is a datum defined by the physics of the reservoir (Figure 6.13). In clean, homogenous, porous sands, the FWL will likely be the same as the hydrocarbon water contact and water saturation will vary with height above the FWL in a predictable way. In heterogeneous sandstones, water saturation will vary as a function of porosity and permeability, making identification of the FWL challenging. Geologists and petrophysicist often describe the increase in water saturation towards a hydrocarbon water contact as the 'transition zone', but to a reservoir engineer, the transition zone is where both oil and water are produced during production.

There are two primary sources of data for saturation height modelling: core-derived capillary pressure measurements and saturation estimates from log data. Capillary pressure (P_c) is expressed in terms of the interfacial tension between the wetting and non-wetting fluid phases, σ, and the contact angle between the wetting phase and the rock surface, θ, as follows:

$$P_c = \frac{2\sigma \cos\theta}{r}$$

where r is the effective pore radius.

In the laboratory, the fluids involved are either water and mercury or simulated oil and brine, depending on the experimental method, and therefore need to be converted to reservoir conditions using the following equation and conversion values presented in Table 6.2.

$$P_{cRes} = \frac{P_{cLab}(\sigma \cos\theta)_{Res}}{(\sigma \cos\theta)_{Lab}}$$

Table 6.2 Conversion of laboratory capillary pressure data to reservoir conditions.

System	Contact angle θ (degrees)	Interfacial tension σ (dynes/cm)
Laboratory conditions		
Air–water	0	72
Oil–water	30	48
Mercury–air	140	480
Generic reservoir conditions		
Gas–water	0	50*
Oil–water	30	30

Source: Worthington (2002).

The height-related capillary pressure data are related to a saturation height relationship using the following equation:

$$H = \frac{P_{\text{cRes}}}{g(\rho_1 - \rho_2)}$$

where g is the gravitational constant and ρ_1 and ρ_2 are the densities of water and hydrocarbon, respectively. Capillary pressure is a function of pore throat size, rather than pore volume, and is therefore subject to the effects of confining pressure at reservoir conditions. Care should always be taken when building a database of capillary pressure data to ensure consistency in experimental methods and conditions; different laboratories may use different techniques or equipment resulting in a systematic error.

Before being able to develop a log-derived saturation height relationship, it is necessary to convert measured depth values to true vertical depth sub-sea (TVDSS). This is best done using a directional survey and the appropriate algorithm in the log analysis package. The log saturation data should only include good-quality data from the cleanest and thickest sands to eliminate uncertainty over clay-bound water and shoulder effects of the input resistivity logs.

Worthington (2002) identified three categories of saturation height relationship: single- and multi-predictor algorithms and normalized functions. Ideally, each rock type should have a unique saturation height relationship based on either geological or petrophysical properties. Cannon (1994) coined the term *petrofacies* to establish a link between geological and petrophysical attributes of a unique,

log-derived facies predictor, characterized by definitive mean values of porosity, permeability and water saturation. Depending on the data available, it is possible to generate different saturation height relationships.

6.3.5.1 Single-Predictor Algorithms

This category is the simplest, using only height as a predictor of water saturation (Skelt and Harrison, 1995).

$$S_w = aH^b \quad \text{or} \quad \log S_w = c \log H + d$$

where a, b and c are regression constants. These simple equations are often used to describe saturation in specific porosity bands or petrofacies; however, they have limitations when applied in 3D models unless conditioned by the geological descriptor as well.

6.3.5.2 Multi-predictor Algorithms

These are more complicated algorithms that incorporate porosity and/or permeability in the relationship. Cuddy *et al*. (1993) proposed a solution that relates height to bulk volume of water (BVW), the product of porosity and water saturation.

$$\text{BVW} = aH^b \quad \text{alternatively} \quad S_w = \frac{aH^b}{\phi}$$

where ϕ denotes porosity and a and b are regression constants. If the input variables show a log-normal distribution, such as permeability, then these equations can be rewritten as:

$$\log \text{BVW} = k + a \log H - \log \phi \quad \text{and}$$
$$\log S_w = k + a \log H - \log \phi + c \log k$$

where c is a regression constant.

6.3.5.3 Normalized Functions

An example of the third type of relationship is the Leverett J-function (Leverett, 1941) that relates porosity and permeability to saturation through the following equation:

$$J_{(S_w)} = \frac{P_c}{\sigma \cos\theta} \sqrt{\frac{k}{\phi}}$$

where P_c is the pressure differential between the FWL and the measured point ($P_c = \text{gH}(\rho_1 - \rho_2)$) and the $\sigma \cos\theta$ term is the surface tension and contact angle from laboratory experiments. When using

log-derived saturation data as input, it is not necessary to include the contact angle and viscosity terms as the data are already at reservoir conditions, so only height and fluid density are required as additional input. When plotting saturation against height for different rock types, it becomes apparent that permeability has a marked influence over saturation regardless of the height above the FWL (Figure 6.14).

One advantage is that a J-function can be determined based on facies or region, leading to a more discrete way of modelling. There are a number of pitfalls in saturation modelling, including a complex filling history that may lead to different relationships in parts of the field. The saturation model is supposed to represent initial conditions, so wells drilled after production has started may have lower reservoir pressures complicating the observations.

Having generated the saturation height relationship, the results in the well should be compared with the petrophysicist's estimation from logs. Both methods are dependent on the reliability of laboratory measurements for a robust solution. As ever, a compromise is often required before proceeding to distribute the property through the model. If possible, a specific saturation height relationship should be established for each facies or porosity class to avoid the problem of

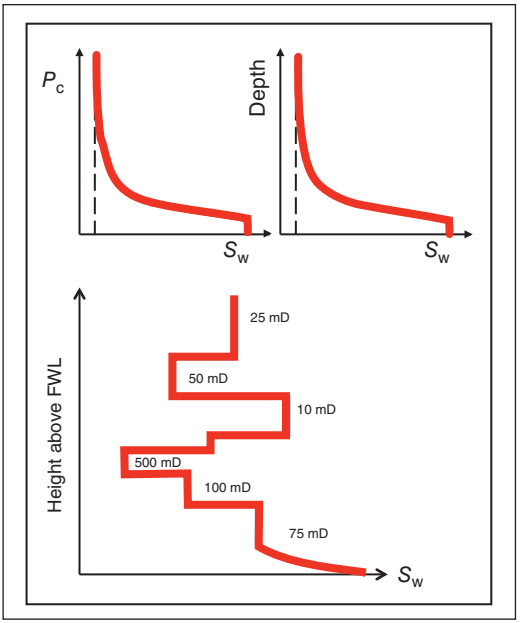


Figure 6.14 The relationship between capillary pressure, height and permeability demonstrating the impact of rock quality on water saturation. *Source*: Cannon (2016). Copyright 2016, John Wiley & Sons.

high water saturation values in cells with good reservoir properties far above the FWL. This is one of the first QC checks a peer reviewer will make.

6.3.6 Modelling Net-to-Gross (NTG)

An arbitrary classification of the reservoir into sand and shale automatically introduces the concept of net and non-net rock in the gross thickness in a well or gross rock volume of a model. In the real world, however, the sand content of the reservoir is variable, leading to the need for a property that reflects this variability, hence the concept of a NTG ratio. In classic map-based techniques, NTG is a very important factor when modelling the reservoir. This is because there is insufficient vertical resolution in the 2D model; however, in a 3D grid-based model, the vertical resolution is taken into account in the grid building.

Net reservoir in a well is usually generated by the petrophysicist based on a cut-off in estimated shale volume (V_{sh}); sometimes a porosity cut-off may also be used independently or in conjunction with shale volume (Figure 6.15). If you need to build a facies model that will give similar results, you must agree a facies scheme that either drives the choice of cut-offs or reflects those applied by the petrophysicist: you cannot work in isolation. Never forget that NTG is a ratio, so when

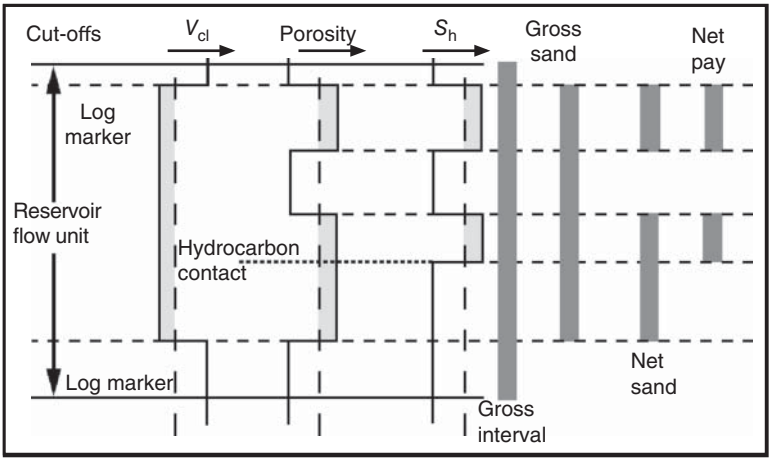


Figure 6.15 Net-to-gross (NTG) terminology, whatever approach you take be consistent. *Source*: Cannon (2016). Copyright 2016, John Wiley & Sons.

combining values from wells or zones, it is necessary to compare both the net and the gross thickness.

When building a facies-constrained model, target volumes are set for each reservoir property and the background is usually set to non-reservoir, thus automatically introducing a NTG relationship. Use the mantra 'does it add volume or flow' to help define what is net reservoir. The key to understanding NTG and applying it in reservoir modelling is to be consistent in your terminology and definitions across all the disciplines. One important issue to remember is that in blocking the facies data, we have introduced a change in the log-derived NTG property due to the upscaling of the data; as a result, the input and the blocked data will not always be consistent.

Total property modelling (TPM) is an approach where all the rock properties are explicitly modelled and cut-offs only applied if required after modelling (Ringrose, 2008). In this case, neither cut-offs nor NTG are part of the process (Figure 6.16). As good-quality rocks are modelled alongside poor-quality rocks, it is possible to test the impact of different cut-offs on the in-place hydrocarbon volume. The main advantage of TPM is that the link to the dynamic model is more easily established because the sequence of upscaling from well to blocked data to geo-model is traceable and all cells in the simulator that do not meet the cut-off criteria can be set as non-reservoir.

6.3.7 Incorporating Seismic Attributes

Seismic attribute data can provide soft information about the following:

- Facies types or lithology (e.g. sand/shale)
- Petrophysical data (mainly porosity and fluids)

In this context, soft means that the seismic information should be expressed in a probabilistic framework due to its non-uniqueness. Facies trends or porosity trends are perhaps the most used information from seismic attributes.

6.3.7.1 Preparation

The most important thing when bringing seismic data into analysis is the difference of scale. Seismic data measure properties on several orders of magnitude greater than the log or core sampling interval. Hence, it is mandatory to upscale the log information to the seismic

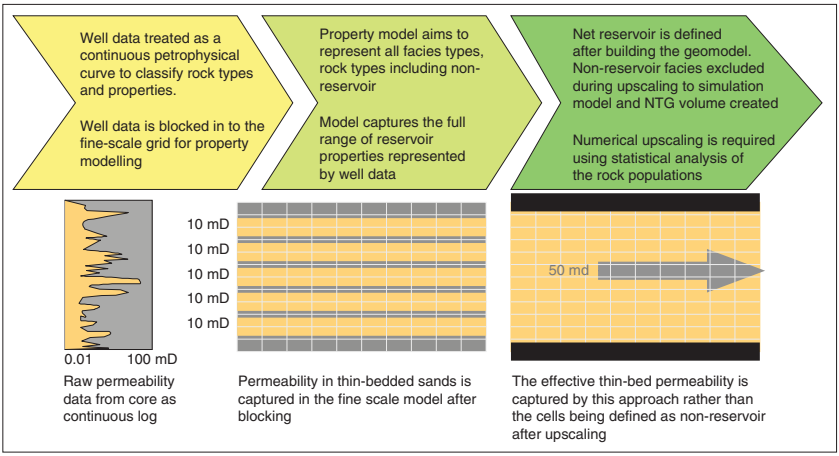


Figure 6.16 Total property modelling (TPM) avoids the need to apply NTG until upscaling properties for simulation. *Source*: Ringrose (2008). Copyright 2008, Ringrose.

resolution. Often several scales (i.e. upscale over different intervals) must be investigated to find a relationship between seismic attributes and geo-properties. The analysis should be carried out in the depth domain as all geo-property modelling will be performed in depth. Secondly, a rock physics study should be carried out to verify the findings.

6.3.7.2 Use in Modelling

The seismic attributes can be included in the modelling in two ways:

- As an intensity map, a 2D grid
- As point information in a 3D grid, that is re-sampling into the grid

For both methods, a probabilistic transfer function should be made. Using a 3D function is very difficult because it requires an almost perfect match at the wells. A small shift in the 3D seismic attribute grid could destroy your results completely. The most robust method is to use an intensity map.

6.3.8 How Many Realizations?

Stochastic modelling means that you can create an infinite number of equally probable realisations from a particular scenario. One of the main reasons to do stochastic modelling is to get an understanding of the uncertainty in your model predictions based on the difference between the realisations. Deterministic methods such as interpolation or kriging only generate a single result.

A scenario is a set of deterministic inputs to modelling, for example a conceptual geological model where the geologist believes that the channel reservoir has wide channels as opposed to narrow channels. These may represent two alternative models.

A realisation is the result after modelling a particular distribution of channels based on the geological concept (wide channels) and the well data. When using facies and petrophysics in stochastic mode, you will get a different realization depending on input seed. All these realizations reflect an uncertainty that arises from sparse hard data (wells) combined with natural variability. In some model set-ups, the uncertainties in input distributions are also included.

The question still remains regarding how many realizations are required to test the uncertainty and how should these be ranked for dynamic simulation? As a rule of thumb, you need minimum 10 realizations of each model scenario to achieve a representative sample. From a statistical point of view, this is probably not enough

to cover the full uncertainty, but it provides an idea of the spread. If you need to run a more complete uncertainty study, at least 100 realizations are required.

6.3.9 Quality Control

Verification of a porosity and permeability model:

- When trends are used, check the residual variables. The variability should be less than the initial variability as the trend now is subtracted.
- Check also for outliers by cross-plotting all original porosity observations against the trend estimates.
- Perform simple kriging of the residuals and look for bulls-eyes in this context.

However, even though the trend may fit well with all observations, the trend may still give unrealistic estimates in parts of the grid far away from any observations.

- Check the global distribution of such a trend model. *Ad hoc* solutions such as cut-off values are often used for solving such problems.
- It is likely that the residual correlations are less than the original correlations.

Some of the dependencies are most likely incorporated in the trends. It may be wise to cross-plot the trends and highlight location and properties for possible outliers.

- Validate that all residual distributions fit with the Gaussian assumption.
- Check the assumption of multi-normality by cross-plotting against all correlated parameters (i.e. their transformed residual distributions).

6.4 Rock Typing

Rock typing is a process that should combine geological and petrophysical characterization at the core scale that can be applied at the wireline log and even seismic scale. A geological facies or facies association will often comprise more than one rock type, suggesting that rock types are linked to depositional processes at the lithofacies scale. However, it is difficult to characterize let alone model every lithofacies described by the sedimentologist, so a pragmatic approach to exercise must be imposed; 5–10 rock types should be sufficient

to describe most reservoir types, and less is often better. The term *petrofacies* has been coined for these geological constrained rock types (Cannon, 1994).

A simple workflow for rock typing has been established, which can work in both clastic and carbonate reservoirs:

1. Describe core and use petrography to classify core plugs by dominant lithology and texture, look for zone patterns.
2. Group core analysis points by dominant lithology and plot porosity/permeability, identify discrete porosity classes.
3. Perform regression analysis on discrete data 'clouds'.
4. Integrate Pc data where available to determine pore size distributions for discrete lithologies.
5. QC results by comparing actual versus predicted permeability.
6. Correct log-derived porosity (ϕ_{eff}) with core porosity (QQ plot).

For example, in a fluvial reservoir, the following facies or facies associations may be identified:

Facies association	Facies		
Channel (30%)	Channel lag (5%)	Active channel fill (25%)	Channel abandonment (10%)
Overbank (20%)	Minor channel	Crevasse splay	
Floodplain (50%)	Heterolithics	Soils, coals, etc.	

However, the floodplain deposits may be considered as one non-contributory rock type in terms of storage capacity and flow potential; in reservoir modelling terms, this is often 'back ground'; these deposits tend to have the highest γ ray response. The channel deposits can be characterized by three capillary pressure profiles representing different pore geometries but can also be recognized in core and on log as 2–3 m-thick sand bodies with a blocky profile at the base becoming bell-shaped towards the top as the grain size becomes finer. Overbank deposits are associated with both channel and floodplain facies but will be represented by thinner channel bodies and discrete sandy events. It may be possible to group petrophysical rock types from different facies associations where their capillary pressure profiles are similar.

An all-encompassing concept to capture property variability in a facies model is that of the (hydraulic) flow zone: unfortunately, this concept can mean different things to different people. A hydraulic flow zone is related to the geological facies distribution but may differ in terms of boundaries and is seldom vertically contiguous. It is defined by geological characteristics such as texture and mineralogy and petrophysical properties related to them, porosity, and permeability and capillary pressure. A hydraulic zone is defined as 'the representative elementary volume (REV) of total reservoir rock within which geological and petrophysical properties that may affect fluid flow are internally consistent and predictably different from other rock volumes' (Amaefule *et al*., 1993). However, what does this mean to different disciplines?

- *To a geologist*: it is a definable 3D facies object such as a fluvial channel or a carbonate shoal.
- *To a petrophysicist*: it is a 2D correlatable zone with similar petrophysical properties.
- *To reservoir engineer*: it is a 3D reservoir layer that has a consistent dynamic response in the reservoir simulator.
- *To a reservoir modeller*: it is all these things!

Amaefule *et al.* (*op cit*) presented a robust and effective way of integrating core and log data to better characterize fluid flow in a reservoir. Their approach is used to identify hydraulic (flow) units and to predict permeability in uncored intervals or wells while retaining a link to depositional facies. The classic discrimination of geological rock types has been based on observation and on empirical relationships established between porosity and the log-of-permeability, but often permeability can vary by 1–3 orders of magnitude over the same porosity range. There is no physical relationship between porosity and permeability; rather permeability is dependent on grain size and sorting, and therefore pore throat distribution. Their method uses a modified Kozeny–Carman equation and the concept of mean hydraulic radius. The equation indicates that for any hydraulic unit, a log–log plot of RQI against normalized porosity (PhiZ or ϕ_z) should produce a straight line with unit slope, whose intercept where porosity is equal to unity defines a unique flow zone indicator (FZI) for each hydraulic unit. The defining terms are all based on overburden corrected core-derived porosity and permeability data.

Without going into all the theory, the practical application is relatively straightforward once a simple facies model has been established.

1. Cross-plot core porosity against core permeability and define one or more correlation lines related to the facies identified. Try to apply these relationship(s) through the uncored interval in a well to test their robustness.
2. Create the log–log plot of RQI versus PhiZ and compare with the previously defined facies; is there correspondence? Can the relationship be used predictively?

$$\text{RQI} = 0.0314\sqrt{\frac{k}{\phi_e}} \qquad \text{PhiZ}(\phi_z) = \left(\frac{\phi_e}{1-\phi_e}\right)$$

$$\text{FZI} = \frac{\text{RQI}}{\phi_z}$$

   On the log plot of RQI against PhiZ, all samples with similar FZI values will lay on a straight line with unit slope, having similar pore throat distribution and thus belong to the same hydraulic unit.
3. Permeability is calculated using an appropriate hydraulic unit relationship with its mean FZI value and porosity. This can be an iterative process, as the results should converge with the core data.

$$k = 1041\ \text{FZI}^2 \left[\frac{\phi_e^{\ 3}}{(1-\phi_e)^2}\right]$$

4. Once the porosity permeability relationship has been robustly established for each facies or rock type on the core data, it can be applied to the log-derived porosity data in all wells again by facies or rock type.
5. Where capillary pressure data are available, these hydraulic units should also describe different rock types based on the wetting phase saturation values. This means that each rock type can also be characterized in terms of a saturation height relationship.

For a fully worked out example, refer to Corbett and Potter (2004).

6.5 Carbonate Reservoir Evaluation

Carbonate reservoirs, limestone and dolomite in the main are very much more difficult to analyse petrophysically than clastic rocks because of the more complex pore structures and networks commonly encountered. Carbonate minerals are generally less stable than quartz and are altered more readily during diagenesis resulting in irregular and unpredictable pore geometry. These in turn affect

the relationships established previously, especially for formation resistivity and thus water saturation. Although the normal methods of log analysis hold up in a simple intergranular or intercrystalline carbonate, they are less successful in vuggy, moldic or fractured limestone. It is often necessary to apply other interpretation strategies to unlock the hydrocarbon potential of carbonate reservoirs. For a complete review of carbonate reservoir characterization, I would recommend a book of the same name published in 1999 and written by F. Jerry Lucia.

6.5.1 Rock Fabric Classification

Carbonates are often classified in terms of their lithology, limestone or dolomite; their bioclastic and chemical components resulting in grain types and size; and also pore type. In each case, the dominant petrophysical element is the pore type; however, to integrate geology, it is necessary to consider the depositional environment and post-depositional history of the reservoir to understand the controls on porosity and permeability. Carbonates lend themselves to a rock typing approach for property modelling.

Carbonates fall into three pore types: interparticle pores; separate vuggy pores and interconnected vuggy pores and fractures. Each class has a different pore size distribution and connectivity resulting in different pathways in the rock fabric through which an electrical current can pass, thus making carbonate rocks highly sensitive in terms of the Archie cementation and saturation exponents '*m* & *n*'. As logged formation resistivity changes in a carbonate reservoir, the challenge is to determine whether this is a function of the water saturation or the porosity of the formation; in other words, is it the '*m*' or '*n*' term in the saturation equation that is varying, or both?

Interparticle pores can be described in terms of particle size and sorting and the resultant porosity. Rock fabrics are described as being grain or mud-dominated (also termed *matrix-dominated*) in some cases. Particle size can be related to capillary pressure measurements to establish pore size distributions, the largest pores having the lowest displacement pressure. Lucia (1983, 1999) established that important displacement pressure boundaries could be established at 20 and 100 μm that define three separate permeability fields (Figure 6.17). These may be incorporated with the rock fabric description to better characterize non-vuggy lithologies. These relationships may be used for limestone and dolomite, or crystalline carbonates.

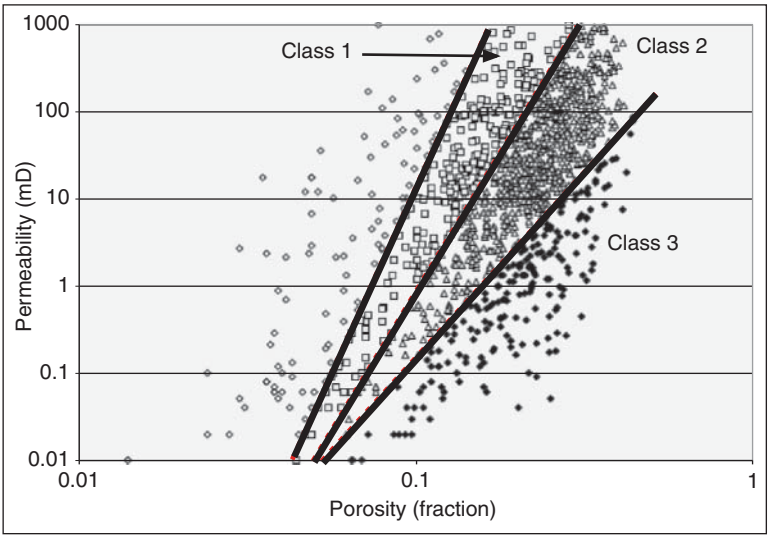


Figure 6.17 Carbonate rock-type classification based on Lucia (1999). The example shown is from a non-vuggy dolomitic limestone and significant displacement boundaries are established at 20 and 100 μm pore throat sizes, defining the separate permeability fields. *Source*: Cannon (2016). Copyright 2016, John Wiley & Sons.

Class 1 (>100 μm): Limestone and dolomitized grainstone; large crystalline grain-dominated dolopackstone and muddy dolostones.

Class 2 (20–100 μm): Grain-dominated packstone; fine-medium crystalline grain-dominated dolopackstone; med crystalline muddy dolostones.

Class 3 (<20 μm): Mud-dominated fabrics and fine crystalline dolostones.

Vugs are usually the product of dissolution of fossil fragments or depositional grains and may be isolated or connected. Lucia (1983) defined these as separate or touching vuggy pores; separate vugs are only connected through the interparticle pore network, whereas touching vugs form an interconnected pore network independent of interparticle porosity. Separate vugs are usually fabric selective and include intra-fossil pore spaces such as closed bivalve shells, dissolved grains (oomolds) or crystals and intragrain microporosity. Touching vug pore systems are generally non-fabric selective and significantly larger than the original particle size, forming extensive pore networks including caverns, collapse breccia and fracture systems.

6.5.2 Petrophysical Interpretation

6.5.2.1 Porosity

In carbonates, the neutron and density tools give a representative estimate of total porosity; the sonic log measures the connected porosity only, so will give a lower porosity estimate in vuggy rock fabrics. In all other aspects, the tools work the same and the results are interpreted using the same workflow; however, the need for core calibration is even greater in carbonate reservoirs because of the greater variety of lithologies, rock types and pore systems. The γ ray response in carbonates is typically <20 API and generally lacking in character, unless there are discrete shale layers. As a result, lithology determination is usually best made with the density log as each of the component has a distinctive bulk density value between 2 and 3 g/cm^3. The neutron log will give a lithology-independent porosity value based on the presence of hydrogen alone; care does need to be taken with complex mixed lithologies to get the correct proportion of each mineral component, especially if salts are anticipated.

Gypsum ($CaSO_4 \cdot 2H_2O$) is a hydrated calcium sulphate and the precursor of anhydrite in evaporite sequences. The neutron porosity log will respond to the water of crystallization in the gypsum and give an erroneous, higher porosity; the density of anhydrite is significantly greater than many other common minerals and will also give inaccurate porosity measurement unless the bulk density is corrected for the presence of anhydrite. In non-vuggy carbonates, the standard interpretation methods can be adapted for the different lithologies, for example:

$$\text{Bulk density } (\rho_{\text{bulk}}) = \rho_{\text{fluid}} \cdot \phi + (2.71V_c + 2.84V_d + 2.98V_a + 2.35V_g + 2.65V_q)$$

where V_c, V_d, V_a, V_g and V_q represent the varying volume proportions of limestone, dolomite, anhydrite, gypsum and quartz, respectively, that make up the rock matrix.

6.5.2.2 Water Saturation

In a carbonate with intergranular or intercrystalline porosity, water saturation calculated using the Archie equation is generally reliable; although where different porosity types are present, other methods need to be employed to determine hydrocarbon saturation. These include the use of an additional textural parameter (W) and log-derived approaches such as bulk volume water calculations,

production ratio index and moveable hydrocarbon index. The real challenge with carbonates is that their rock fabric and pore-type distribution can change rapidly and unpredictably making a single solution difficult to implement.

A variable 'm' value in a well can be calculated for each interpretation level if both neutron density and sonic logs are available. The neutron-density combination estimates total porosity in the reservoir and the sonic log estimates connected porosity, in this case vuggy porosity. Nugent *et al*. (1978) developed the following relationship that works well in carbonates with vuggy and moldic porosity:

$$m \geq \frac{2(\log \phi_s)}{\log \phi_t}$$

where ϕ_s and ϕ_t are the sonic log porosity and the neutron density (total) porosity log, respectively. A separate vuggy porosity can be estimated from the equation $\phi_{vug} = 2(\phi_t - \phi_s)$ for use in oomoldic porosity (Nurmi, 1984), leading to a value for matrix porosity alone:

$$\phi_{matrix} = \phi_t - \phi_{vug}$$

These terms can now be used in the equation above to calculate the variable 'm' on a level-by-level basis where oomoldic porosity is recognized, a simple rock typing method for carbonates.

Lucia and Conti (1987) working the laboratory and borehole data further refined this relationship by plotting a series of 'm' values against the 'vug:porosity ratio' (VPR) to give a straight line relationship where

$$\text{Cementation factor } (m) = 2.14(\phi_{sv}/\phi_t) + 1.76$$

$$(\phi_{sv} = \text{separate vug porosity})$$

The value of 'm' for non-touching vuggy carbonates can vary between 1.8 and 4, and the presence of fractures or touching vugs the value can be less than 1.8. If the correct 'm' value is not used in the Archie equation, the water saturation will be too high if it is <2 and too low if >2; 2 being the default value for 'm' in most cases.

Asquith (1985) gives several case studies where an alternative approach to classical log analysis is required in carbonate reservoirs. In the case of the Canyon Reef reservoir, Scurry County, Texas, two separate interpretations had two very different water saturations because the wrong 'm' had been used in the analysis; the default value gave a porosity of 24% and water saturation of 22%, but on production test, the well flowed water. Using a Picket Plot approach combining

true resistivity, porosity, water saturation and porosity exponent, it is possible to estimate from the slope of the line a true value for '*m*' in the water leg that can then be applied in the analysis. A higher value for '*m*' is estimated as 3.7, reflecting a complex vuggy porosity distribution and when applied to the analysis gives a water saturation of 74% in the reservoir.

BVW calculation is quite simple, the calculated porosity times the calculated water saturation in a well, and can be used to identify those hydrocarbon-bearing zones at irreducible water saturation (S_{wirr}) and thus likely to flow free from water under production. A reservoir at irreducible water saturation exhibits BVW values that are constant throughout regardless of the porosity, as all formation water is held through surface tension or capillary pressure exerted by the pore network. Asquith (1985) presented a table (Table 6.3) comparing BVW with grain size and carbonate porosity type that suggests that at values of BVW < 0.04, a reservoir will produce water-free hydrocarbons. The table also shows that for vuggy reservoir to produce water free, they are required to have very low BVW because vuggy pores hold little water by surface tension or capillary pressure.

Table 6.3 Bulk volume water at irreducible water saturation as a function of grain size and type of carbonate porosity.

Bulk volume water (BVW)		
Grain size (mm) after Fertl and Vercellino (1978)		
Coarse	1.0–0.5 mm	0.02–0.025
Medium	0.5–0.25 mm	0.025–0.035
Fine	0.25–0.125 mm	0.035–0.05
Very fine	0.125–0.0625 mm	0.05–0.07
Silt	<0.0625 mm	0.07–0.09
Carbonate porosity type		
Vuggy		0.005–0.015
Vuggy and intercrystalline		0.015–0.025
Intercrystalline or intergranular		0.025–0.04
Chalky		0.05

Source: Asquith (1985). Copyright 1985, American Association of Petroleum Geologists.

The production ratio index (PRI) method is based on the assumption that vuggy porosity does not contribute greatly to formation resistivity, as the pores are unconnected; matrix porosity controls formation resistivity as measured by the logs (Nugent *et al*., 1978). Combining resistivity with sonic porosity to estimate the matrix water saturation (using Archie) and then multiplying by the total porosity from the neutron density cross-plot gives the PRI:

$$\text{PRI} = S_{\text{ws}} \times \phi_{n-d}$$

A further property of the PRI is that it can be used to estimate the expected initial water-cut at production start-up in carbonate reservoirs characterized with vuggy or moldic porosity: a PRI < 0.02 would indicate water-free production, whereas PRI > 0.04 would indicate water production only. A combination of these different techniques should be used to fully understand hydrocarbon distribution in carbonate reservoirs; however, the need for a core data to calibrate both the petrophysical and the geological parameters is essential for a successful outcome.

Microporosity in carbonate rocks commonly occurs as a result of micritization of muddy sediments, commonly as in-fill to fossil moulds; diagenesis converts the fine-grained sediment to a crystalline form that holds abundant bound water. In this case, an electric current flows more easily through the rock than were it to follow a tortuous pathway around grains or particles. The result is a log response indicative of higher water saturation than in reality, as much of the response is a function of bound water in the micropores. Keith and Pittman (1983) developed a model of mega- and microporosity to classify different types of carbonate rocks as bimodal or unimodal in terms of the porosity mixture. To do this, they plotted true resistivity (R_{t}) against the ratio of the flushed zone resistivity and resistivity of the mud filtrate (R_{xo}:R_{mf}). Consistently, carbonates with both porosity types (bimodal) show a lower ratio of R_{xo}:R_{mf} than do carbonates with mega-porosity; this is a direct result of the higher volumes of bound water associated with the microporosity that cannot be flushed during the drilling process, reducing the reading of the shallow reading resistivity tool.

Guillotte *et al*. (1979) designed a graphical approach to define a single textural parameter, W, combining the Archie parameters 'm & n' using plotting core-derived porosity and permeability on a log-log plot. Lines of constant W are derived from the following relationship

relating water saturation and porosity with R_w and R_t:

$$S_w \times \phi = \left(\frac{R_w}{R_t}\right)^{1/W}$$

Values of W will vary from field to field, reservoir to reservoir and rock type to rock type, so careful calibration is required.

From all of the above examples, it is obvious that carbonate reservoir requires special handling to be characterized correctly and that core data are a pre-requisite for all approaches. Carbonate petrophysicist have to be imaginative and innovative in the application of the available data to extract the last drop of information and oil of these complex rocks.

6.6 Uncertainty

The range of uncertainty on the property models is small compared with the larger scale issues of depth conversion and facies modelling; however, getting the FWL wrong in the model will have a large impact on in-place volumes. It is always possible to set an uncertainty range on a porosity value, but if you adopt a TPM approach, you will be sampling all the porosity ranges because you will not be using cut-offs. We only really tinker with porosity because we are trying to compare with pure petrophysical uncertainty models developed in a spreadsheet: we will look at this in the next chapter.

6.7 Summary

Property modelling is challenging because we try to push the data we have too far; 'making a silk purse out of a sow's ear' as the saying goes. It is important to capture the distribution of porosity for volumetric estimation and permeability to understand flow in the reservoir, but in reality, we have made so many assumptions along the way that we should be very cautious with the results.

7

Volumetrics and Uncertainty

There are two primary methods of volumetric estimation: direct measurement using volume calculation made on a static model and indirect measurement using dynamic performance analysis (Figure 7.1). The accuracy of either method is a function of measurement of static properties such as porosity and net reservoir thickness, or the quality and frequency of pressure or temperature measurement and hydrocarbon fluid analysis and production. We are most concerned with static, volumetric models where the key input data are the gross rock volume (GRV), followed by porosity, net-to-gross (NTG) ratio, the hydrocarbon saturation and the formation volume factor (FVF: the volume expansion that occurs when oil or gas is produced to the surface).

$$\text{HCIIP} = \frac{\text{GRV} * \emptyset * \text{NTG} * (1 - S_w)}{\text{FVF}}$$

Knowledge from offset analogous wells/fields is often used where there is sufficient information to build a robust input data set. The value of a 3D saturation model is in a more accurate distribution of reservoir fluids; accuracy is improved through better geometric representation of fault compartments, the modelling of saturation constrained by facies or rock type and the application of saturation height functions related to a free water level. When completed, the model can be used to analyse connected volumes and drainable volumes attributed to specific objects or facies.

The GRV is derived from a top reservoir structure map, area-thickness maps and a hydrocarbon water contact or FWL; these may be used to construct a simple volume map or a 3-D

Reservoir Modelling: A Practical Guide, First Edition. Steve Cannon.

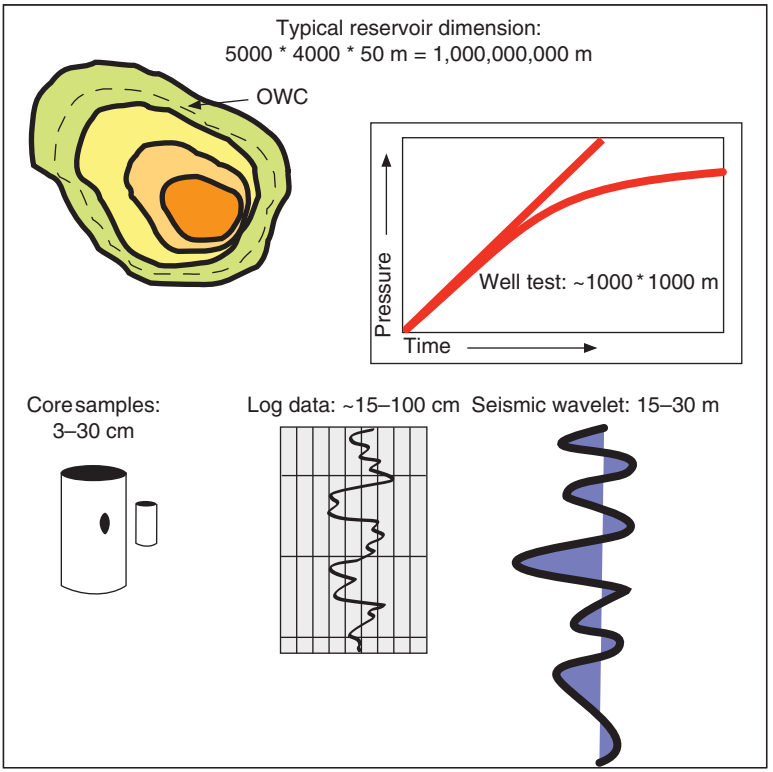


Figure 7.1 Scales of measurement: from core data through log, seismic and well test to demonstrate the several orders of magnitude difference between the various sources. *Source:* Cannon (2016). Copyright 2016, John Wiley & Sons.

geocellular model. Mapped volumes are measured with a planimeter and isochore maps are summed for different areas using macros. We have learnt from the foregoing how to generate a 3-D geocellular model. Porosity is estimated from well data and distributed by the chosen method, deterministic or stochastic; net-to-gross is determined from a facies model or well data; the water saturation is distributed using a height above FWL relationship and the volume factor calculated from laboratory PVT experiments or offset data. Dynamic methods of volumetric estimation include material balance, decline analysis and simulation.

Often the best way to develop a volumetric model is to refine an existing deterministic estimate of hydrocarbon pore volume (PV) or

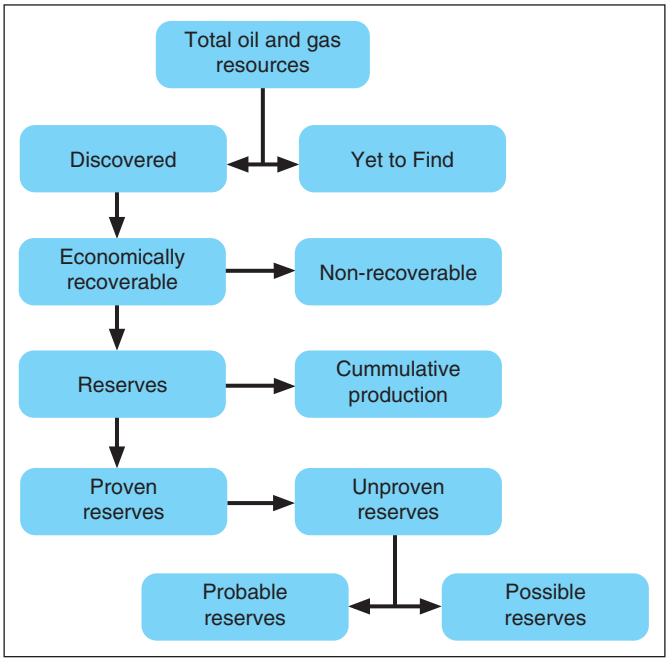


Figure 7.2 Standard oilfield terminology for resources and reserves.

HIIP. This may then form a base case model against which further estimates can be compared. In this way, the impact of different contributing parameters and their uncertainty can be assessed. The oil and gas industry has a consistent approach to describing the resources in a field or a basin (Figure 7.2).

A common *deterministic* approach to defining reserves is in terms of Proven, Probable and Possible categories; the *probabilistic* approach is to refer to P90, P50 and P10 deciles on the cumulative distribution curve. These terms are quite specific:

- *Proven* – Lowest risk, reasonable certainty of production under existing economic conditions; a 90% probability of production and similar to the P90 probabilistic definition of there being 90% chance of producing the booked amount.
- *Probable* – More likely to be produced than not; at least a 50% probability of production and similar to P50 such that a business decision can be made on the 'most likely' or 'expected' outcome.

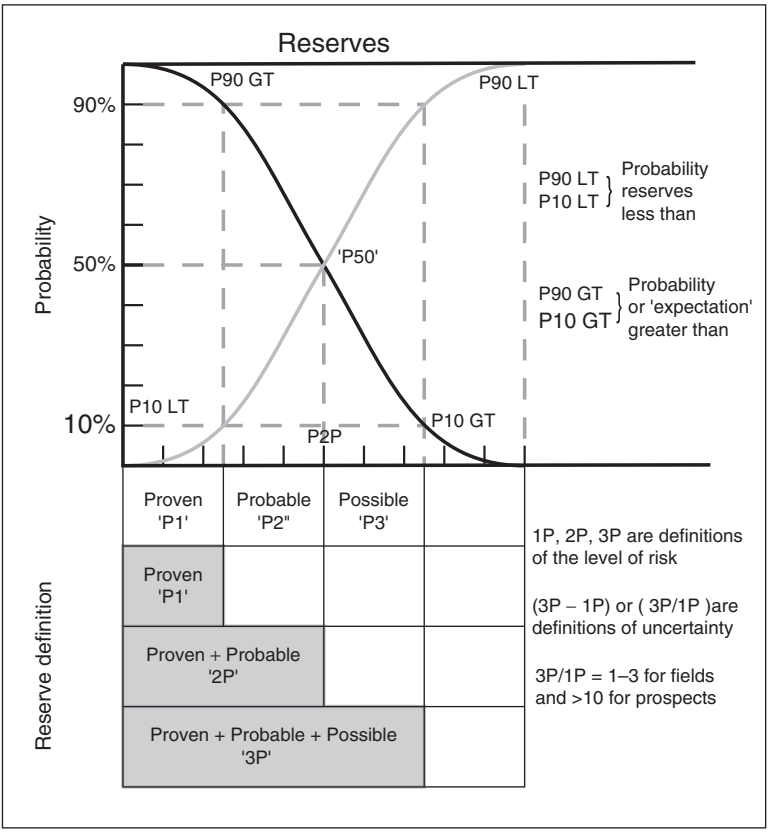


Figure 7.3 Deterministic and stochastic reserves terminology.

- *Possible* – More speculative, a higher degree of risk with at least a 10% chance of being developed; an upside case for the maximum return on the investment.

It is also possible to use both types of classification to compare or rank prospects, projects and investment opportunities. The terms 1P, 2P and 3P define the risk associated with a project, whereas comparisons of 1P and 3P can define the degree of uncertainty: the ratio of 3P:1P should be between 1 and 3 for fields and greater than 10 for prospects (Figure 7.3). A spread of around 3–5 should be expected for a field that is pending development.

7.1 Work Flow Specification

Volumetric calculations are performed with the geological model to establish an idea of in-place volume and to generate calibration parameters for resource estimates. The basis for the volume calculations is definitions of a set of reservoir regions. For the simulation model, volumetric calculations are performed as a form of quality control, to check consistency with the geo-model. Correct initial volumes are the foundation for correct production estimates. However, do not expect exact volume comparison because after upscaling, the GRV will be different, usually less in the simulation model: most companies accept up to 5% difference between the two models. Greater differences indicate a fundamental change in the input parameters, usually the method of distributing water saturation. It is always worth checking the volume calculation at each stage of the process to ensure that the correct values are being used correctly. We will look at uncertainty modelling and the impact of input data ranges later.

7.1.1 Volumetrics Terminology

Traditionally, geologists and reservoir engineers use different volume definitions, related to the definition of the fluid contacts. To avoid confusion in the definitions, the following terminology should be used:

Free water level (FWL): The true vertical depth where the capillary pressure is zero and the reservoir is 100% water bearing.

Transition zone: An interval from which both oil and water are produced at the same time; this is different to the alternative in which hydrocarbon saturation reduces towards the water contact, not the same as a FWL.

Gross rock volume (GRV): The total volume of the model including both bulk rock volume (BRV) and PV. This may be either for a whole model or only that part that is hydrocarbon bearing, that is, above an oil or gas water contact.

Bulk Rock Volume (BRV): Total volume of rock in the model, that is, GRV-PV.

Hydrocarbon Bulk Rock Volume (HCBRV): Equal to the BRV between top reservoir and the free water level.

PV: The volume of pore space in the model regardless of the fluid content, that is, GRV–BV.

Hydrocarbon pore volume (HCPV): Equal to the PV between top reservoir and the free water level.

Gas initially in place (GIIP): The volume of the model filled with gas at discovery.

Stock tank oil initially in place (STOIIP): The equivalent oil-filled BRV at surface.

7.1.2 Products and Results

For the geo-model, the following products should be created:

- Definition of a segment or region model. Regions should be given a unique number and eventually a name. The region definition should be available both as a set of polygons and as a geo-grid parameter (FIPNUM – fluid in place number).
- Cell values for PVs.
- Cell values for oil volumes.
- Cell values for bulk volumes BV, to be used as weighting parameters in upscaling.
- Cell values for hydrocarbon-filled bulk volumes, BVoil and BVgas.
- Cell values for hydrocarbon pore volume HCPV.
- Cell values for stock tank oil originally in-place STOIIP.
- Integration of above parameters per segment in the geo-model, giving STOIIP, HCPV and so on.

For the reservoir simulation model, the following products should be created:

- Fluid region definitions in simulation model, as a FIPNUM parameter.
- Total volumes from simulation model: PV and fluid volumes.
- Segment volumes from simulation model: PV and fluid volumes.
- Quality control of simulation model versus geo model. Definition of PV modifications to the simulation model.

7.1.3 Necessary Data

Volume calculations should be performed with the grid models, and the following quantities are necessary for both geo-grid and simulation grid:

- Porosity distribution – porosity model.
- Non-reservoir distribution, represented as a facies-specific property or as a specific facies distribution – NTG model.

- Water saturation distribution – S_w model.
- Volume factor distributions – FVF model.

In addition, the spatial distributions of fluid contact levels are needed.

7.2 Volumetric Model Work Flow

For the geological model:

- Establish volume and/or saturation regions, based on block boundaries, faults, contacts, zones, well/template regions and so on. Store and document all closed polygons defined.
- Volume calculations for the geological model are fairly straightforward when the distributions for porosity and water saturations are defined.
- Report volumes and save the results.

For the simulation model:

- When the grid construction is finished, grid cells can be grouped into fluid regions based on the region definitions introduced in the geological model.
- Bulk volumes can be calculated for segments and total for comparison with the geological model.
- Following assignment of cell volume properties, calculate PVs in the model and compare with the geological model on total and/or segment basis. If the difference is small enough to be explained by differences in grid construction, adjust the PV in the simulation model to match the geo-model.
- When fluid contacts and water saturation model are introduced into the simulation, calculate fluid volumes and compare with the geological model on total and/or segment basis.
- Again perform necessary adjustments in PV to match fluid volumes in the geo-model.

7.2.1 Volumetrics with Stochastic Models

When stochastic modelling is used for some or all zones in the reservoir, a single realization is not necessarily representative with respect to the expected volumes in the reservoir. Volume calculations must then be performed for a selection of realizations and used to

estimate expected (average) volumes together with P10 and P90 estimates, uncertainty modelling.

Volumes reported for the flow simulation model are usually related to official numbers for fluid volumes, and a problem arises if the simulation model volume differs significantly from the official volumes.

When ranking geological models for use as a basis for construction of a single simulation model, a geological model should be selected with volumes close to the 'official' or 'expected' numbers; however, there is no way to ensure that the actual hydrocarbon distribution is the same, only the volume. Alternative approaches can be used in the following process:

- The volumes of the simulation model can be adjusted in correspondence with official data. This adjustment should not be large.
- The volumes of the simulation model are not adjusted, and the production volumes must be reported together with the initial volumes, for comparison with the official volumes.

7.2.2 Volumetrics and Grid Resolution

The volumes calculated will always to some degree depend on the grid resolution. For most fields, the variation will be inside the uncertainty interval. If necessary, the sensitivity to grid resolution in the hydrocarbon bulk volume can be investigated by constructing a grid with finer resolution for comparison. This grid can eventually be constructed for a smaller part of the total field.

If the fine-grid bulk volumes turn out to be significantly different from the volumes calculated from the ordinary grid, a bulk volume correction can be used for the volumes coming from the ordinary model. Corrections must then be calculated for gas-filled bulk volume and oil-filled bulk volume, respectively. The bulk volume corrections must be further applied also for the fluid volumes. We must then assume that volume corrections between the models can be evenly distributed.

The same type of bulk volume corrections can be used if faults in the geo-grid are zigzagged for correspondence with the simulation model.

7.2.3 Geo-model/Simulation Model Comparison

Firstly, check PV against the geological model. The cause of large discrepancies should be identified and eventually corrected; we

will look at upscaling from geo-model to simulation model later in Chapter 8. This is typically related to the following:

- Incorrect horizon definition in the simulation model.
- Incorrect representation of faults.
- Large grid cells in parts of the simulation model.
- Errors in upscaling of porosity.

Porosity errors can be eliminated by also using bulk volumes in the comparison.

Following the PV correction, check fluid volumes. Usually, correct fluid volumes by first correcting gas and water, then oil. This is to avoid a situation where the oil volume is altered by later additional volume corrections.

7.2.4 Reporting Volumetric Results

The volumes calculated from the geological model should be stored as a text file, clearly identifying the basis for the calculation. Most software products will generate a spreadsheet output for filing.

The documentation should include the following:

- The name of the geological model used for the calculation.
- The values used for FVFs and eventually solution factors.
- If several regions are involved in the calculation, a plot showing the region number definition should be generated.

7.3 Resource and Reserves Estimation

We estimate resources so that we can measure the commerciality of a discovery or development. Different organizations have different processes to estimate the volume of hydrocarbons and different hurdles to jump before sanctioning a project as commercial; we are providing our best estimates of hydrocarbons in place so that these decisions can be made successfully. Companies are in the business of making money and satisfying their stakeholders and investors; increasingly, the stakeholders include the national governments where they operate. Operators need to manage their assets effectively to conduct business and to manage expectations, so the value of a portfolio of assets must be estimated for the timing of future development. Additionally, most publically quoted international oil and gas companies have a legal

requirement to disclose the value of the resources and reserves to stock exchanges so that investors can make informed decisions: stock exchanges do not make a recommendation to potential investors but ensure that a company is viable trading concern. It is worth re-iterating that we *estimate* reserves and resources and that the process is not an exact science.

7.3.1 Petroleum Resources Management System (PRMS)

In 2011, Society of Petroleum Engineers (SPE), World Petroleum Council (WPC), American Association of Petroleum Geologists (AAPG) and Society of Petroleum Evaluation Engineers (SPEE) jointly released new guidelines for the application of the Petroleum Resources Management System (PRMS). PRMS is a means of defining hydrocarbon resources and reserves designed to provide a 'consistent approach in estimation of quantities, evaluating development projects and presenting the results within a comprehensive classification framework' (SPE, 2011). The definitions and guidelines are designed to provide a common reference for the international petroleum industry, including national reporting and regulatory disclosure agencies, and to support petroleum project and portfolio management requirements. They are intended to improve clarity in global communications regarding petroleum resources. One particular advantage of the system is that it can be applied to conventional and unconventional volumes of hydrocarbons.

The system is designed to differentiate between resources, all naturally occurring hydrocarbons in a field or licence area or a basin, and reserves, which are quantities of hydrocarbon that are expected to be commercially recoverable by a sanctioned project. Reserves must satisfy four criteria: they must be discovered, recoverable, commercial and remaining to be produced from a given date. Both categories may be classified as proved (P1), probable (P2) or possible (P3), with a range of uncertainty estimated either deterministically (low-best-high) or stochastically (P90-P50-P10) (Figure 7.4). A table with the definitions of each class of resource or reserves is presented (Tables 7.1–7.3).

To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. There must be a

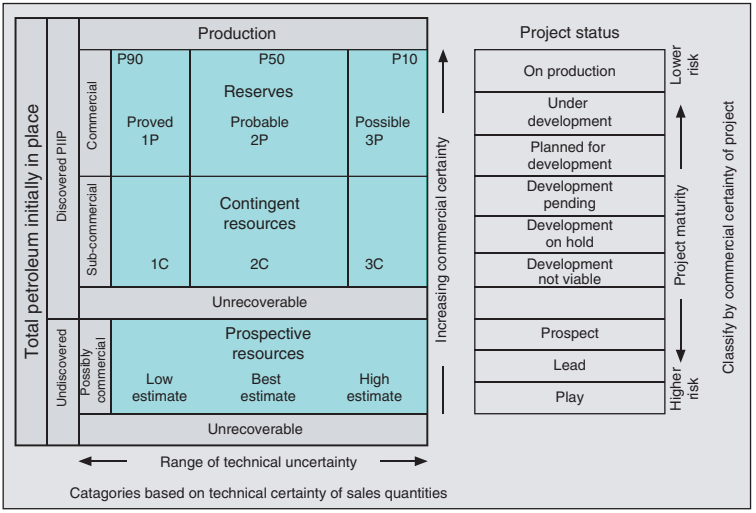


Figure 7.4 Petroleum Reserves Management System (PRMS, 2011) terminology for resources and reserves. *Source:* Reproduced with permission of Society of Petroleum Engineers.

Table 7.1 Reserves definitions as recommended in PRMS.

Class/sub-class	Definition	Guidelines
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions	Reserves must satisfy four criteria: they must be discovered, recoverable, commercial and remaining based on the development project(s) applied. Reserves are further subdivided in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their development and production status
On production	The development project is currently producing and selling petroleum to market	The key criterion is that the project is receiving income from sales, rather than the approved development project necessarily being complete. This is the point at which the project 'chance of commerciality' can be said to be 100%
Approved for development	All necessary approvals have been obtained, capital funds have been committed and implementation of the development project is under way	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget
Justified for development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained	In order to move to this level of project maturity, and hence have reserves associated with it, the development project must be commercially viable at the time of reporting, based on the reporting entity's assumptions of future prices, costs and so on ('forecast case') and the specific circumstances of the project. There should be a development plan in sufficient detail to support the assessment of commerciality and a reasonable expectation that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time

Source: Reproduced with permission of SPE.

Table 7.2 Contingent resources definition as recommended in PRMS.

Class/sub-class	Definition	Guidelines
Contingent resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies	Contingent resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status
Development pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g. drilling and seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan
Development on hold	Discovered accumulations where project activities are on hold and/or where justification as a commercial development may be subject to significant delay	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal/evaluation activities are required to clarify the potential for eventual commercial development
Development not viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions

Source: Reproduced with permission of SPE.

Table 7.3 Prospective resources definition as recommended in PRMS.

Class/sub-class	Definition	Guidelines
Prospective resources	Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations	Potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analogue developments in the earlier phases of exploration
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target	Project activities are focused on assessing the chance of discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under feasible development scenarios
Play	A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific leads or prospects for more detailed analysis of their chance of discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios

Source: Reproduced with permission of SPE.

high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. Although five years are recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

7.4 Uncertainty Modelling

We live in an uncertain world, but uncertainty falls into two categories, statistical (aleatoric) and systematic (epistemic): when Dirty Harry asked the criminal whether he felt 'lucky' it was because neither knew how many bullets were left in the pistol, a systematic uncertainty. Someone playing Russian roulette with one bullet in a chamber is playing with statistical uncertainty. There is also a need to distinguish between uncertainty and risk: risk is a measure of the likelihood of a discrete event, whereas uncertainty describes a range of equiprobable outcomes. Uncertainty comes about because of a lack of knowledge, not a binary choice between two possibilities; by taking a risk, you leave yourself open to the possibility of failure and the financial consequences that result. The best definition of uncertainty is that it is a measure of how poorly we understand or can predict an outcome.

We can reduce our degree of uncertainty by taking more measurements of a property or seeking an expert opinion on some aspect of the data, in other words improving our knowledge of the reservoir. Our statistical understanding of the uncertainty can be improved by sampling more possible outcomes until we have a complete probability distribution of a property. We hope that over time, as we move from exploration to appraisal and certainly when we make the financial decision to proceed with development that the uncertainty reduces, however, this is not always the case as we saw in the introduction (Figure 1.2).

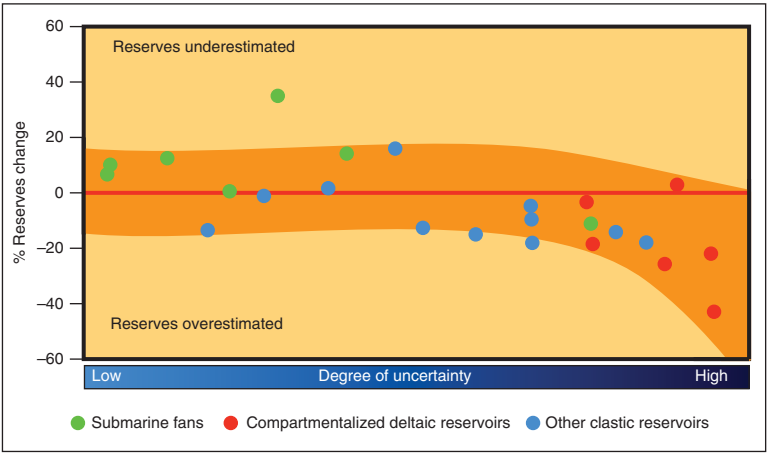


Figure 7.5 Uncertainty in oilfield reserves classified by depositional environment. *Source:* Speers and Dromgoole (1992). Copyright 1992, Schlumberger Oilfield Services.

The whole process of building a 3D reservoir model is founded on many uncertainties; those of data quality, interpretation and sample representation are particularly crucial at all stages of the workflow. Work published by BP (Speers and Dromgoole, 1992) demonstrates this uncertainty in terms of depositional environment: the degree of uncertainty is greatest in compartmentalized deltaic reservoirs and least in submarine fans (Figure 7.5). The greatest volumetric uncertainty is related to the reservoir envelope; 30% of the range in results is related to the profile of the top structural surface. A single model, whether it is deterministic or stochastic in origin, is insufficient to capture the range of equiprobable results from the input data. The challenge associated with uncertainty modelling is as much with handling and ranking the numerous cases. We have looked at broad uncertainties at each stage in the modelling process, now is the time to bring it all together.

7.4.1 Work Flow Specification

The uncertainty evaluation process comprises management and quantification of all uncertainties related to all predictions of volumes, target locations, target properties and so on. The list of products from uncertainty evaluations will depend heavily on the purpose of

the study, as well as type of reservoir setting to be described and the complexity of the development.

Uncertainty predictions are generally based on very complex relationships between input parameters. These relationships are handled most easily through a 3D Monte Carlo approach, that is, by creating a sufficient number of complete realizations based on drawing from distributions in the input parameters. The product will then be a selection of realizations, together with associated probability density functions (PDFs). The range of results has a direct link to the randomly generated 'seed' used by the algorithm to create each realization; in fact, the seed can be a variable in the process and should be investigated as another uncertainty.

For both well planning and flow simulations, a ranking of the realizations must be produced, to be able to keep the number of realizations involved in later work low. For estimates of volumes or resources, a suggested report standard should contain as a minimum:

- The PDF plot, also showing the associated normal distribution of the volume.
- The cumulative density function (CDF) plot, with lines showing the percentiles P5, P10, P20, P50 (median), P80, P90 and P95.
- A table containing summary of the mean value, the standard deviation and the percentiles P5, P10, P20, P50 (median), P80, P90 and P95.

The distributions and tables listed above should be given for all volume quantities given in the following product list:

Horizon Model Uncertainty

- BRV uncertainty distribution.
- Hydrocarbon-filled bulk rock volume (HCBRV) uncertainty distribution.
- Realizations of the horizon model representing HCBRV P10, P20, P50, P80 and P90.

Fault Model Uncertainty

If necessary, a selection of n realizations is needed for further flow simulations, to quantify effects of fault uncertainties on the production forecast. Proper methods for ranking of these realizations are missing.

Property Model Uncertainty

- STOIIP volume uncertainty distribution.
- GIIP volume uncertainty distribution.
- *n* property realizations ranked on STOIIP or GIIP. These should be constrained to avoid realizations conflicting with observations.

Flow Simulation Uncertainty

- Recovery factor uncertainty distribution.
- Production profile distribution plot.
- Distribution of various production profile characteristics, such as time to water breakthrough, time to end-of-plateau production and so on.

Again, necessary data for the uncertainty modelling depend critically on the purpose of the study.

Horizon Model Uncertainty

- Seismic time maps (base case).
- Seismic interpretation uncertainty maps, Δt, defined as P95 residual maps (if map value is 10 metres, it implies 95% probability for the interpreted reflector is 10 m from the equivalent synthetic reflector you would have mapped).
- Velocity map down to top and base reservoir. Note that local modifications of the velocity field to tie exactly at wells should not be included in these data sets.
- Velocity uncertainty maps and/or linear model parameter distributions.
- Well tie observations (TVDSS).

Fault Model Uncertainty

- Property model (petrophysical and/or facies distributions).
- Distributions for flow parameters related to seismic faults.
- Sub-seismic fault parameter distributions (length, displacements, etc.).
- Fault sensitivity studies from reservoir.

Property Model Uncertainty

- The P10, P20, P80 and P90 structural realization grids.
- Multiple realizations of the property model in base case grid.

7.4.2 Uncertainty Model Workflow

Estimation of uncertainties is a multidisciplinary task that must be kept in mind during the whole modelling process. Here, stages are flagged where special focus on key uncertainties should be addressed.

7.4.2.1 The Project Plan

Handling of uncertainties should be discussed in the project plan, based on the available knowledge at this initial stage in the process. It is important early in the process to reduce the number of important uncertainties to avoid wasting time on describing quantities where base case predictions are sufficiently robust. Identification of the key uncertainties can lead to a top down modelling procedure that may be sufficient for some reservoirs.

The project plan should focus on handling of uncertainty in the initial stage of the modelling process, that is, seismic interpretation and building of the seismic framework.

7.4.2.2 Seismic Uncertainty and Bulk Volume Uncertainty

In the final stage of building the seismic framework, a grid corresponding to the framework should be built. Together with this, work focusing on uncertainty in BRV can be initiated. The following items should be addressed:

- Volumetric uncertainty in BRVs related to the horizon uncertainty model, comprising uncertainties in depth conversion, seismic interpretation and well tie.
- Volumetric uncertainty in BRVs related to seismic fault positions and sub-seismic fault distributions.
- If fluid contacts, data are available at this stage, volumetric uncertainty in HCBRV related to all uncertainties in the seismic framework.

Create as many realizations of the horizon model as possible to estimate the listed probability distributions.

With present software tools, effect of faults cannot be included when creating the volume uncertainty distributions. Faults are, however, included in the volume calculation performed with the deterministic model defined.

The P50 estimate from the uncertainty modelling must be compared with the deterministic estimate, and the distribution must eventually

be calibrated relatively to the base case model. The deterministic model may be assumed to represent the best possible and most accurate prediction of the P50 value.

In addition to the base case (deterministic) seismic framework, alternative frameworks should be constructed from realizations representing the P10 and P90 estimate. This will be further used as alternative frameworks for the property modelling. If possible, also build models representing a P20 and P80 estimate.

A multidisciplinary meeting should be arranged to present results for BRV uncertainty and to discuss handling of uncertainties in the structural framework later in the modelling process. This should include a discussion of processing of uncertainties while building the geological framework, that is, the combined uncertainty in seismic framework and in isochore models. Also, handling of structural uncertainty in flow simulations should be addressed.

7.4.2.3 Geological Uncertainty and Fluid Volume Uncertainties

With knowledge gained from the geological property analysis, a new multidisciplinary meeting should address uncertainties in the geological modelling and update the plan for further processing of uncertainties.

For STOIIP uncertainty, a normal procedure should comprise the following:

- From each of the alternative seismic frameworks developed in the previous paragraph, build a corresponding geo-grid for property modelling. The grid dimension must be the same for all grids. Then, estimate STOIIP distribution by transforming the base case property distributions into the alternative grid models.
- Cross-plot corresponding pairs of HCBRV and STOIIP and evaluate if a linear transformation of the BRV distribution to a STOIIP distribution may be used for representing the structural uncertainties.
- Derive the STOIIP distributions based on multiple realizations of properties in the base case model, by special focus on possible important aspects, as for example:
  - Facies proportions.
  - Special facies object dimensions.
  - Special facies property distributions.

At least, 10 realizations should be executed.

7.4.2.4 Geological Uncertainty and Flow Simulations

Typically, the time frame allows for flow simulations to be performed on only a very small number of realizations. The person responsible for developing the realizations is responsible for ranking of the realizations. Ideally, selected realizations should be constrained on available production history, such as well-to-well communication, minimum volume available for a well and pressure barriers.

The number of realizations must be selected based on the planned use in the simulation model, that is, recovery estimates, history matching or well planning. For recovery estimates and well planning, typically a 'low', 'most likely' and a 'high' case could be used. For history matching, it is preferable to select only a 'most likely' case, perform a simulation and then use the experience from this to constrain selection of a new realization.

Flow sensitivity studies should be used to evaluate main uncertainty hypotheses, eventually locate specific areas where a more thorough modelling is necessary. This is especially important for fault modelling, including effects of fault sealing processes.

7.4.3 Ranking Realizations

In many cases, it is practically impossible to do simulation on 100 geological realizations. The reason for that is simply that reservoir simulations are too computer demanding. Therefore, we need to do some kind of ranking (sorting) before simulation, where we choose an appropriate set of realizations.

Base case – which base case?

If you do 100 geological realizations using a facies-modelling algorithm, all realizations are equally likely. Hence, there exists no 'base case' as in deterministic modelling. The reason for that is that deterministic modelling focuses on expected values, whereas stochastic modelling focuses on variability and uncertainty. Some argue that they can choose an average STOIIP realization as base case, but that may be quite dangerous in individual well planning because the planned track may be 'lucky' or 'unlucky' in that single case.

'Anchoring' is the process of selecting a best guess despite the wide uncertainty in the range of results; the anchor point has too great influence on the subsequent analysis of uncertainty. In other words, people cannot accept that the minimum value could be so low or that the maximum could be so high, and we tend to overcompensate.

7.4.3.1 Ranking Methods

Using simulation in ranking realizations may sound like a silly idea, but actually it is a good approach. The reason for this is that you can screen how realizations vary with your production history. The realizations that best match history are applied in further work. If you are not able to get close to production history with any of your realizations, you will have to go back to your property model and probably change input settings.

Streamline simulation is designed to quickly rank realizations. However, this method is best suited for zones that have on-and-off facies, such as fluvial reservoirs. In addition, the method has several fundamental weaknesses, such as single-phase flow only, lack of gravity forces and very simplified well steering. Hence, it may be possible that using this tool will leave the user with a lot of unanswered questions. An example of using streamlines for ranking realization is discussed in the final chapter.

Using visual, qualitative measures is probably the best way to rank realizations. If you are doing well planning, you can make various fences and sections around the well area and visually deduce which realizations should go further to dynamic simulation.

7.4.4 Other Uncertainty Methods

A simple matrix approach using a low–mid–high range of values for each of the key uncertainties, GRV/BRV, NTG, porosity, water saturation and FVF (Figure 7.6), will lead to deterministic values of the lowest–central–highest possible values of the in-place volume.

Variable	Low case	Mid case	High case
GRV(m^3)	15,600,000	18,230,000	19,700,000
FWL(m)	2782	2791	2809
NTG	0.37	0.46	0.48
Porosity	0.23	0.26	0.29
$(1–S_w)$	0.63	0.75	0.81
FVF	1.034	1.045	1.052
STOIIP(m^3)	864,799	1,708,816	2,336,718

Figure 7.6 A deterministic method for determining the low–mid–high range of hydrocarbon volumes. This might be the starting point for any volumetric exercise involving 3D modelling.

This can be done in a 3D model or in a spreadsheet; in fact, it is always a good practice to run a statistical uncertainty spreadsheet tool because you can run a thousand cases in the time it takes to run 10 in the 3D model.

Increasingly, the software products are focusing on automated workflows that take into account the interpretation results by applying a meaningful measurement uncertainty. This approach is most applicable in structural modelling where the impact is greatest on in-place volume estimates (Leahy and Skorstad, 2013).

7.5 Summary

In many ways, the final volumetric estimate is the culmination of many weeks of intense work, so it is important that all parties treat the results with respect. Be prepared to take critical questioning, but also be ready to defend the work of the team in delivering the results and do not forget it only an *estimate*.

'All models are wrong, some are useful'

8

Simulation and Upscaling

It is seldom possible for a fine-scaled geological model to be used directly as input for reservoir simulation: the process of upscaling must be undertaken. Upscaling is often an underestimated phase of the workflow; however, by early discussion with the end user, usually a reservoir engineer, the process can be made easier and the results more acceptable. By orienting the grid with due consideration of the main flow direction before starting facies modelling, there is less subsequent manipulation of the model. Discussing what size of model is needed for speedy simulation can help to define the scale of the modelling grid. It is essential that upscaling preserves the architecture and pore volume of the net reservoir to ensure that connectivity in the geological model is consistent with recovery estimates predicted by the simulation model. In general, an upscaled grid will have a fewer number of larger cells, coarser vertical layering and zigzag faults. 'A cynic might describe upscaling as the process of putting incorrect information into the wrong model to get the right answer' (*pers. comm.*) (Figure 8.1): just like history matching, it is a non-unique process; you can be 'playing all the right notes but not necessarily in the right order' (Morecambe and Wise, 1971).

As this is a non-unique solution, it is worthwhile testing the different options to see which gives the best result in terms of the dynamic response in the simulator. Again this is a case for testing the ideas on a prototype model. There are as yet no real alternatives to upscaling, although a number of computer-intensive methods such as parallel processing have been tried, and found wanting.

There are generally two steps to upscaling: the upscaled grid and the upscaled properties. Design of the simulation grid should be part of the overall project design and as discussed should be the first step in the workflow if you know the objective is dynamic simulation.

Reservoir Modelling: A Practical Guide, First Edition. Steve Cannon.

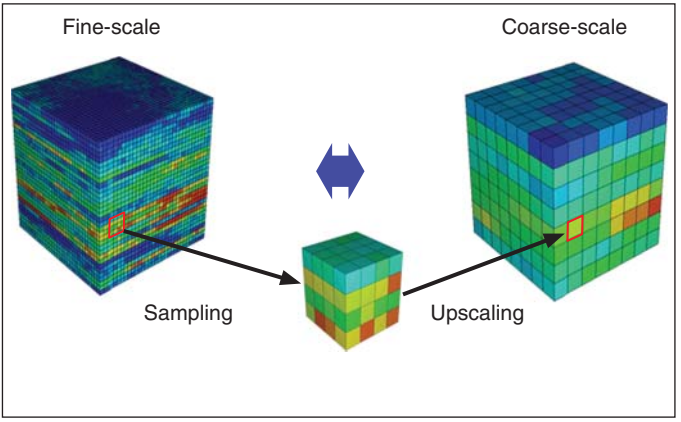


Figure 8.1 Upscaling of reservoir properties is dependent on sampling method, scale and region. *Source*: Reproduced with permission of Schlumberger-NExT.

8.1 Simulation Grid Design

This section describes the process of designing and building a grid for flow simulations. Construction of the simulation grid is strongly connected to construction of the geological grid as discussed earlier. Constructing a grid is a compromise between several requirements, which may be in conflict with each other, as described in the section on model design. The quality of the simulation grid must be evaluated based on the objective of the model.

- Geological framework with horizons and fault cut-off lines.
- Analysis of property data scale.
- Geocellular grid design.
- Fault data for sub-seismic faults and from well-observed faults.
- Well paths for grid design, especially for constructing local grids.

Additional Data

- Fault midlines for quality control.
- Allan diagrams to test for fault juxtaposition and hence connectivity.
- Seismic cube in depth for quality control.

8.1.1 Grid Design Work Flow

The following steps are considered as basic elements in the workflow:

- Define area covered by the simulation grid, that is, polygon defining the model boundary preferably rectangular.
  - Select simulation grid fault model:
    (i) Which faults should be included in the model;
    (ii) Use of sloped/vertical faults.
    (iii) Use of non-zigzag/zigzag faults.
  - Define layering from geological model.
  - Define areal design grid, including boundary lines. This must be done in an iterative loop with the layering to minimize the total number of (active) cells. Avoid grid editing, as these prevent updating of the model.
  - The (i, j, k) origin should be defined in the 'north-western' corner of the model to create a right-handed coordinate system.
  - Remove non-orthogonal and thin/twisted grid cells.
  - Define fault transmissibility, if required, to represent sub-seismic faults.
  - Select cells to be used for numerical aquifers. Large aquifers should be represented by more than one grid cell. This is further discussed in the section Aquifer modelling.
  - If necessary, create local grids based on the well trajectories, local grid refinement (LGR).

8.1.2 What is a Corner Point Grid?

A *corner point grid* is a logical rectangular grid where the coordinates of its eight corners define each grid cell, but where the cell corners in a column of grid cells are restricted, it may be located on four common grid pillars. The grid pillars are the vertical grid lines connecting a column of grid cells. In a corner point grid, the grid pillars must be straight lines. A corner point grid is defined by specifying two points for each grid pillar and then by defining the depth values associated with the corners.

Each cell is identified by integer coordinates (i, j, k) where the k coordinate runs along pillars, and i and j span each layer. Corner point grids are the norm for all major reservoir simulators; unstructured or perpendicular bisector (PEBI) grids have been used for special cases.

A *Cartesian grid* is based on a coordinate system that specifies each point uniquely in a plane, by a pair of numerical coordinates that are assigned distances to a point from two fixed perpendicular lines. This grid coordinate system allows the construction of curved surfaces, faults, in the geological grid. A *logical rectangular grid* is defined as a

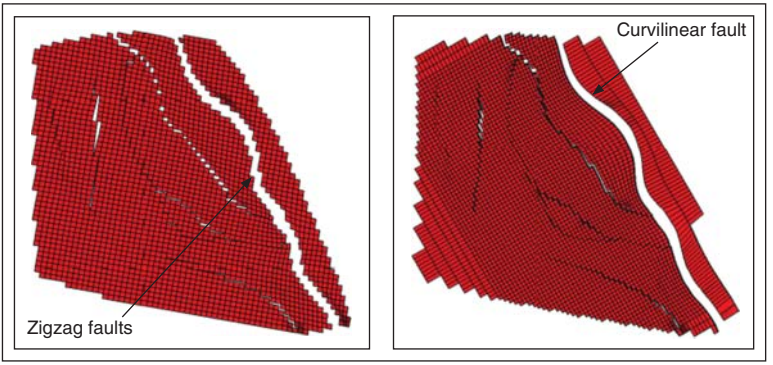


Figure 8.2 Grid resolution aligned to the major structural features creates a more robust and realistic faulted grid. *Source*: Emerson-Roxar.

grid where the grid cells can be organized in a (x,y) uniformly regular coordinate system. No faults may be incorporated and grid pillars are vertical.

As all the grid pillars associated with a column of grid cells must be straight lines, a corner point grid imposes restrictions on what type of faults can be modelled in the grid. Listric faults and Y-shaped faults cannot be modelled with a corner point grid. Note that four corners define a cell surface, and the cell surface is generally not a plane. For calculations involving cell surfaces, this can introduce ambiguity in the location of the cell surface. This is, for instance, the case when calculating the length of a well inside a grid cell, where the intersection points between the grid cell and the well must be determined.

8.1.3 Grid Design Goals

Simulation grid design is an optimization process where various aspects must be balanced against each other:

- The grid should be constructed to represent the main geological features as accurately as possible (Figure 8.2). This should include representation of:
  - (i) Structural elements as reservoir boundaries, layers, faults and so on.
  - (ii) Geological heterogeneities defined at various length scales, such as permeability contrasts and barriers.
- The grid should represent fluid distribution as accurately as possible, including fluid contacts and transition zones.

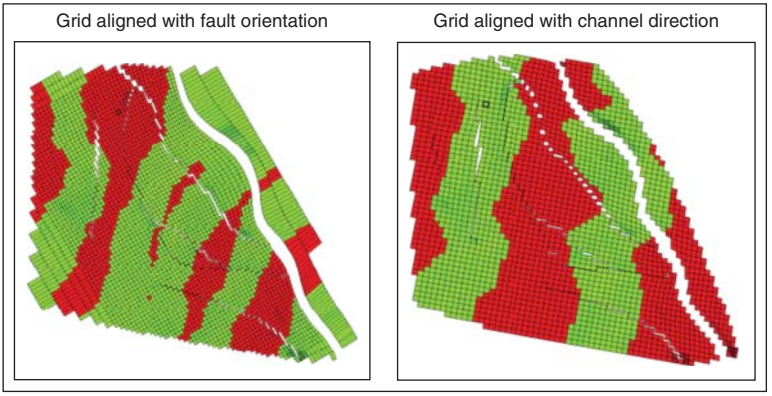


Figure 8.3 When a grid is aligned to the primary flow direction, a better grid for dynamic simulation is created. *Source*: Reproduced with permission of Emerson-Roxar.

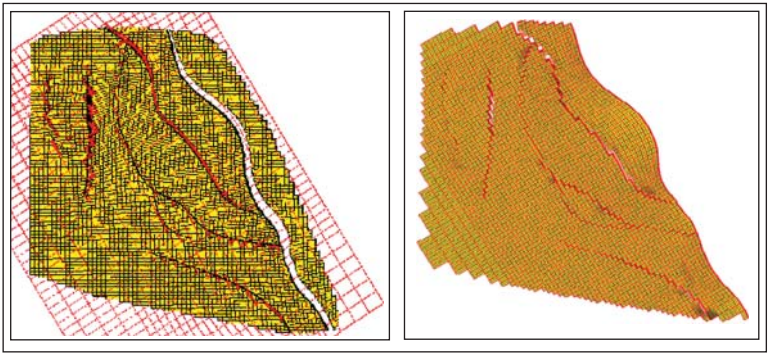


Figure 8.4 The SmartModel concept promotes building the geocellular and simulation grids with the same orientation and complementary dimensions so that upscaling and down-gridding methodologies can be improved. *Source*: Reproduced with permission of Emerson-Roxar.

- The grid should represent flow geometry as accurately as possible (Figure 8.3), using smaller grid cells in areas where important saturation changes may occur.
- The grid should be designed to capture well geometry as close as possible.
- The grid should be constructed to minimize numerical errors (Figure 8.4) related to discretization of the model equations and thus minimize computation time.

It is not really possible to satisfy all these requirements, as they, to some extent, are mutually conflicting.

8.1.4 Grid Orientation Effects

Grid orientation effects are a collective term used to denote errors introduced in the numerical solution caused by the orientation of the local coordinate axes in the grid.

The finite discretization used to approximate the basic model equations introduces a bias in the numerical flow depending on the coordinate directions. Flow in the direction of the grid lines tends to be over-predicted, whereas flow moving diagonally in the grid tends to be under-predicted (Figure 8.5).

Grid orientation effects can arise from several sources:

- The non-linear coefficients in multi-phase equations. Grid orientation effects will vanish when the grid cell size approaches zero. The problem increases for increasing mobility ratio.
- Use of a five-point discretization molecule for non-orthogonal grid cells. The grid orientation effects will not vanish when the cell size approaches zero. The problem can be reduced by application of a discretization molecule with more than five cells involved. Use of non-structured grids also has a positive effect on the grid orientation problem.

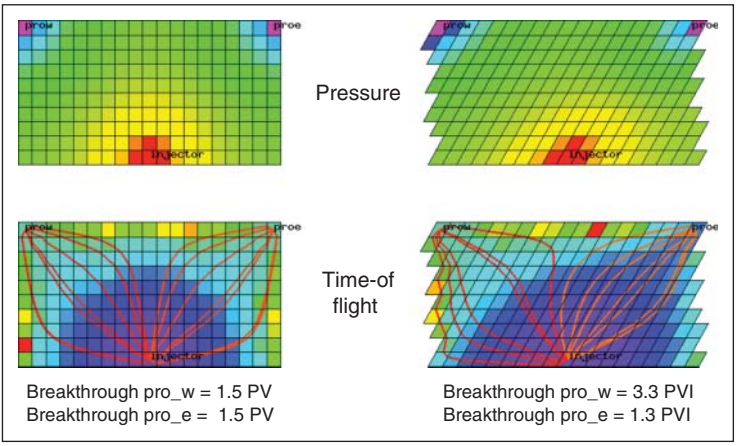


Figure 8.5 Numerical dispersion is created when the simulation grid requires rotation such that the flow paths between wells become distorted. *Source*: Long *et al*. (2002). Copyright 2002, Petroleum Exploration Society of Australia.

The grid orientation effect will also be present in the vertical direction, where, for instance, the grid will slow down flow along the top horizon in a zone using base-conformable grid. A proportional grid should be expected to represent the flow more correctly.

The term *grid orientation effects* is usually reserved for problems found in models with isotropic permeability, but an additional problem arises if the permeability field is anisotropic and the grid orientation does not correspond to the principal permeability axes. Typically, this could arise if the grid is constructed parallel to a well trajectory and not parallel to the geological bedding plane.

8.1.5 Areal Grid Construction

The process of grid construction typically starts with definition of the region that should be covered by the model, followed by definition of internal control lines and grid size. Definition of the model extent should be specified already in the planning stage of the modelling project, as this is linked closely to the extent of the seismic interpretation and the geological model area. Different software tools have their own methods of defining the simulation grid area and internal construction.

An evaluation of surrounding aquifer volumes is necessary as the basis for the definition of the model extent. If a numerical aquifer model is to be used, the grid must contain a sufficient number of inactive grid cells that can be used as aquifer cells.

8.1.6 Areal Representation of Faults

Seen in an areal perspective, a fault is represented by the two cut-off lines in a given horizon. When designing an areal grid, we can select to follow the cut-off lines exactly as in the 3D grid, or we can select to represent the fault as a zigzag line.

The zigzag line gives a poorer fault representation but can yield improved orthogonality in the grid. Note that the correct fault throw should be honoured correctly in both cases. The zigzag representation is often sufficient for flow modelling, as the correct flow between layers is achieved. This could be the case for fault segments where the volume error is negligible or can be adjusted through pore volume modifiers, and where the distance from the fault to wells is not critical.

The following process is advisable for the fault handling:

- Try first a grid construction with no faults present and see how the cut-off lines at the top horizon or an intermediate horizon compare with the grid lines.
- Select (major) faults that should be followed exactly by grid lines and see how this changes the grid construction.
- Add smaller more faults in successive steps until all faults have been included in the model.

The process must usually be performed in an iterative loop to decide on which faults to follow exactly and which to zigzag.

8.1.7 Aquifer Modelling

An aquifer is defined as a geological formation that is storing water and also capable of transporting a significant amount of water. The term *aquitard* is used for a formation that may contain water but is not capable of transmitting significant quantities of fluid under normal pressure gradients.

If an aquifer is to be modelled as a numerical model, one or more inactive grid cells must be selected to represent the aquifer. The following guidelines should be followed when defining the aquifer:

- If the aquifer volume is large, consider representing the numerical aquifer by more than one grid cell areally.
- Select grid cells with a non-zero bulk volume and a 'reasonable' depth value. This is to avoid artificial effects introduced in the aquifer model.
- To avoid unwanted flow connections, each aquifer should be surrounded by inactive grid cells.
- Avoid connecting a water aquifer directly into a hydrocarbon zone, as this can cause instabilities in the model.
- Define separate fluid-in-place region numbers (FIPNUM) for the aquifer cells, to be able to supervise pressure and volumes in the aquifer.

8.1.8 Local Grid Construction

LGR can be used to give better numerical resolution in the vicinity of wells in the model. Note that use of local grids does not necessarily lead to an improved answer. Typically, a better vertical resolution is more important than an improved horizontal resolution. A splitting of the global grid cells in 2×2 is usually sufficient.

Local grid constructions can be performed in the grid-building module. Several options for construction of the local grid are available:

- By digitizing local grid limits.
- From a blocked well.
- From a value parameter definition, defining a group of cells.

Together, this gives large flexibility in the local grid construction.

8.1.9 Quality Control of Grids

There will always be imperfect cells in an upscaled grid, but it is the number of these cells and the volume they represent that decides whether they can be ignored or the grid rebuilt. Perform a visual inspection of the grid, both in 3D and cross sections.

- Check cross sections with correspondence between horizons and grid cells, especially near faults.
- Check areal fault pattern, that is, midlines from geo-model versus fault splits in the simulation model.
- It should be possible to check simulation grid fault modelling versus the seismic cube in depth.
- Check distribution of cell thickness. Avoid large number of very thin grid cells.
- Check for twisted grid cells ('Inside/out cells'), these must be removed.
- Check for layers with overlapping depth, these must be removed.
- Check for isolated grid cells, these can be removed.
- Check the distribution of minimum and maximum angles for the horizontal projection of top and base horizons. Ideally, this should be centred around 90°.
- Check for non-convex grid cells and cells with a large dip towards faults. Both types of cells are accepted by the reservoir simulator, but should be avoided.
- When cell properties are defined, perform a simulation with no wells in the model, to verify that the grid yields a stable model. This is especially important when local grids are included, to select between solution methods for these grids.
- If a numerical aquifer model is used, check initial stability of the aquifers.

Always perform a simulation without wells to check stability!

8.2 Upscaling Property Models

Property upscaling is the process of finding 'effective' values defined on a coarse scale that can represent the distribution of a parameter defined on a finer scale (Figure 8.6). The upscaling process must reflect the planned use of the parameter at the coarse scale. For instance, should upscaling of permeability depend on whether the coarse scale permeability is to be used for cell-to-cell flow, cell-to-well flow or as basis for establishing a capillary pressure relationship on the coarse scale?

There are four equally important factors in upscaling:

- How heterogeneous the upscaling region is?
- How well the length scales are separated?
- The sampling method used.
- The upscaling technique chosen.

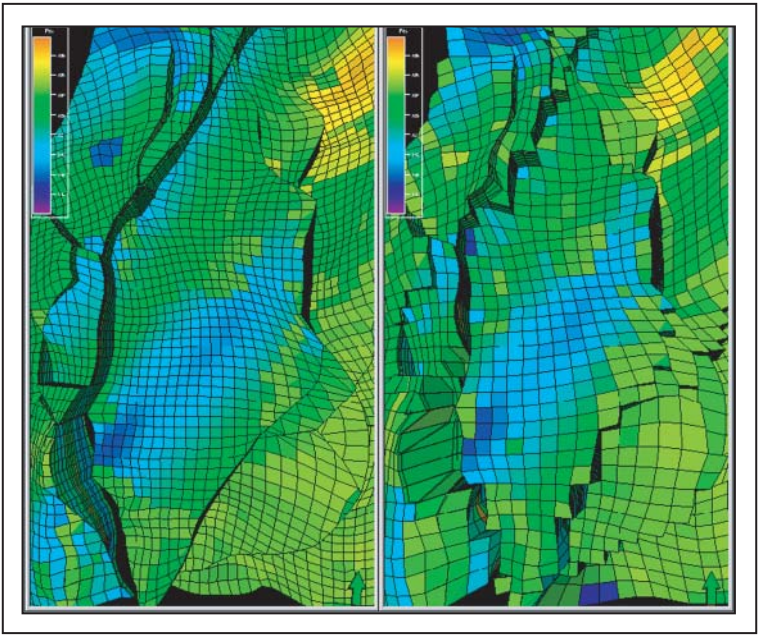


Figure 8.6 The results of upscaling porosity from the fine scale to the coarse scale retain all the primary property distribution and the same overall pore volume. *Source*: Reproduced with permission of Schlumberger-NExT.

A large number of upscaling methods for flow models exist, and selection of the best method can be difficult. For permeability, we often distinguish between static and dynamic methods:

- Static methods are based on performing arithmetic operations on the property data; the calculation of some sets of statistical averages.
- Dynamic methods are based on solving one or several flow equations. The term *flow-based upscaling* is also used as an alternative.

8.2.1 Statistical Averages

A static method is based on using one of the many statistical averages available (Figure 8.7). The most basic methods applied are described below.

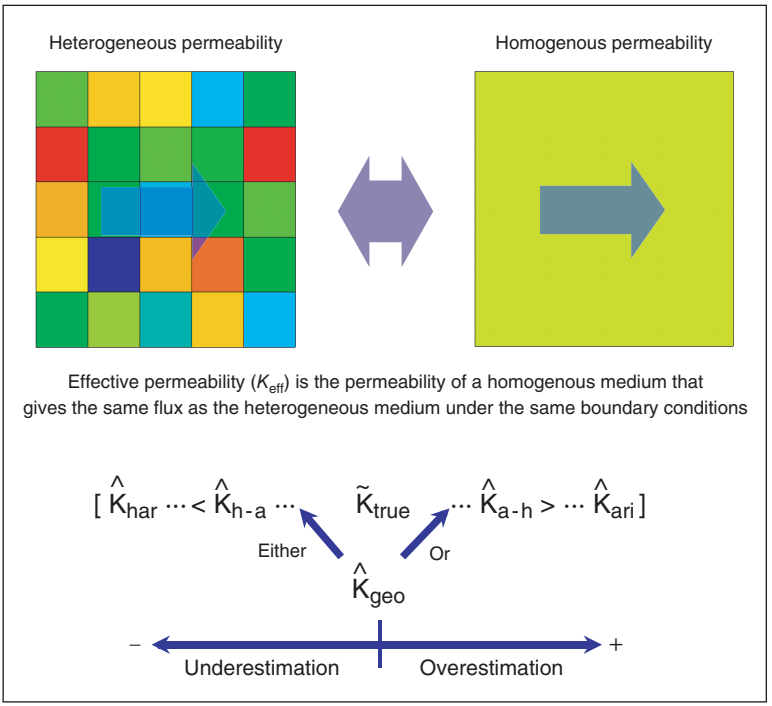


Figure 8.7 Permeability upscaling is a more challenging task and may require different averaging methods or dynamic pressure solver techniques. *Source*: Reproduced with permission of Emerson-Roxar.

- The arithmetic average is the natural average for all volumetric properties such as porosity and shale volume (V_{sh}). It is also the exact value for the horizontal permeability in a perfectly layered reservoir with constant permeability in each layer. A weighted form is often used, where the weights can be bulk volume, layer thickness and so on.
- The harmonic average is the exact upscaled value for the vertical permeability in a perfectly layered reservoir with constant permeability in each layer. Note that the harmonic average is zero if a zero value occurs among the samples. The harmonic average can be weighted in the same manner as the arithmetic average.
- The geometric average is the exact limit for a region where the permeability is log-normal distributed and uncorrelated; that is, there is no coupling between neighbouring points in the reservoir and the distribution is totally random.
- The power law average is a generalized average that includes the basic arithmetic, harmonic and geometric average. Based on the result of any type of upscaling, the corresponding power average value for p can be calculated, for comparison with the basic statistical estimates.
- The arithmetic–harmonic average is a combination of arithmetic and harmonic averages (Figure 8.8a). First, arithmetic averages

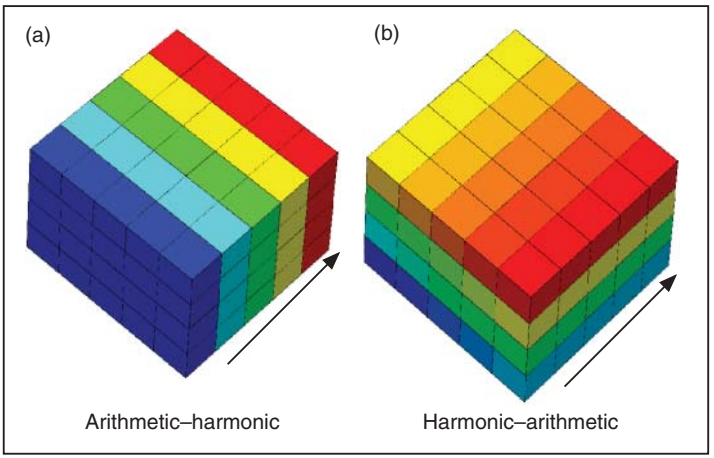


Figure 8.8 Examples of two common averaging methods: (a) arithmetic–harmonic; (b) harmonic–arithmetic. *Source*: Reproduced with permission of Emerson-Roxar.

are calculated for planes perpendicular to the direction where the permeability is to be calculated. Then, the harmonic average is taken for the arithmetic averages. The arithmetic–harmonic average is the exact upscaled permeability in a perfectly layered reservoir with constant permeability in each layer. That means that it gives the arithmetic average for the horizontal permeability and the harmonic average for the vertical permeability.

- The harmonic–arithmetic average is another combination of arithmetic and harmonic averages (Figure 8.8b). First, harmonic averages are calculated along stacks of cells in the direction where the permeability is to be calculated. Then, the arithmetic average is taken for the harmonic averages. For a perfectly layered reservoir with constant permeability in each layer, the harmonic–arithmetic average equals the arithmetic–harmonic average.

8.2.2 Renormalization

Renormalization is an upscaling technique where permeability is modelled by an equivalent resistor network, and Kirchhoff's law for resistor networks is used as an analogue to Darcy's law for incompressible fluids.

The simulation grid cells are divided into a sub-grid where the dimension in each direction is $2n$, where n is a user-defined parameter. A sub-grid consisting of $2 \times 2 \times 2$ cells is selected, and a pressure gradient is applied in the direction where the permeability is to be calculated. This gives an intermediate upscaled permeability for the sub-grid. Grouping on higher levels continues the process until the upscaled value for the simulation grid cell is achieved.

8.2.3 Dynamic Upscaling

In dynamic upscaling, a flow simulation is performed on the fine-scale grid cells in the upscaling region, and it is necessary to specify boundary conditions at the boundary of the region. The result of the upscaling process will generally depend heavily on the boundary conditions selected (Figure 8.9).

The boundary problem is one of the fundamental problems of upscaling. Ideally, the boundary conditions applied in the upscaling should reflect the boundary conditions the coarse cell experiences as part of the total grid during the full-field simulation. For a complex

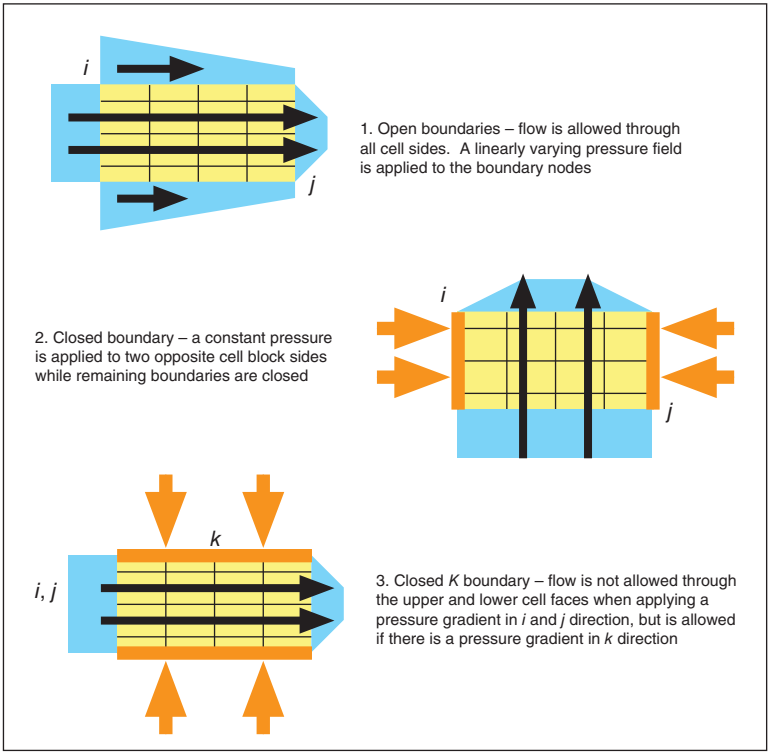


Figure 8.9 Different boundary condition that can be applied to pressure solver upscaling of permeability. *Source*: Reproduced with permission of Schlumberger-NExT.

field simulation, these boundary conditions will vary both in time and space and cannot be properly anticipated.

No-Flow Boundary Conditions

For no-flow boundary conditions, a pressure gradient is applied along each of the coordinate directions, one at a time. The following conditions are assumed:

- Constant pressure over the surfaces perpendicular to the pressure gradient.
- No flux through the surfaces parallel to the pressure gradient. This is an analogue with a laboratory core flood experiment.

Linear Boundary Conditions

For linear boundary conditions, the pressure varies on the boundary in a linear fashion. Here, the pressure applied is a pressure gradient applied in a fixed position, lying inside the simulation grid cell.

Periodic Boundary Conditions

For periodic boundary conditions, it is assumed that the fine-scale permeability is identical in all the simulation grid cells and that the flow is not influenced by the wells. A pressure gradient is applied along each of the coordinate directions, one at a time. The following boundary conditions will then be satisfied:

- The pressure on opposite fine cells differs with a constant on the surfaces perpendicular to the pressure gradient.
- The pressure on opposite fine cells is equal on the surfaces parallel to the pressure gradient.
- The flux through opposite fine cells is equal on all the surfaces.

When assuming that the flux between the fine and coarse scale is conserved for the no-flow and linear boundary conditions and the dissipation (loss of mechanical energy per unit time) for the periodic boundary conditions, an expression of the effective permeability can be derived.

8.2.4 Comparison of Upscaling Methods

Deciding which of the methods to be used is often a matter of trial and error and is always dependent on the available data; if you have well test or production data, then it is a case of trying to match those results. If you only have empirical data, then the simple option is good enough.

The arithmetic average is the theoretical upper bound for the upscaled permeability, whereas the harmonic average is the theoretical lower bound. The geometric average is always lower than or equal to the corresponding arithmetic value and higher than or equal to the harmonic value for the same data set. The arithmetic–harmonic average is a finer upper bound than the arithmetic average, whereas the harmonic–arithmetic average is a finer lower bound than the harmonic average.

Flow-based upscaling using the no-flow boundary conditions will give a lower bound for the effective permeability, whereas the linear boundary conditions lead to an upper bound. The periodic boundary conditions yield an intermediate value. The linear and periodic boundary conditions yield a full permeability tensor.

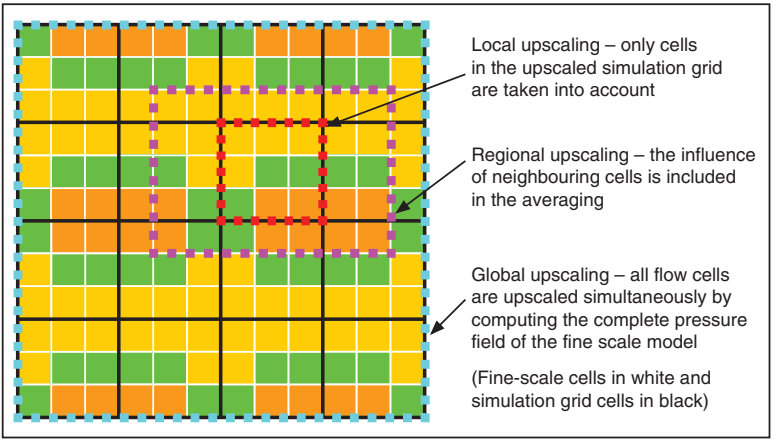


Figure 8.10 Examples of different upscaling regions: local, regional and global. *Source*: Reproduced with permission of Schlumberger-NExT.

The statistical averages are less time consuming than the flow-based upscaling, but the accuracy is generally better for the flow-based upscaling.

8.2.5 Local, Regional and Global Upscaling

Upscaling methods can also be classified as local, regional or global, respectively (Figure 8.10). Local methods are generally less expensive than regional and global methods, but the accuracy is better for regional and global methods.

Local Methods: Upscaling is performed cell-by-cell for the coarse grid. Each coarse cell is treated as a more-or-less isolated region, and only the fine-scale cells that fit inside each coarse cell are taken into consideration in the process. The result usually depends critically on the flow pattern assumed for the coarse cell, that is, the boundary conditions applied to the fine-cell region in the upscaling.

Regional Methods: This is similar to local methods, but the influence of the neighbouring fine cells is accounted for within a limited region around each flow cell; this is done by creating a 'flow jacket' of fine cells around the focus cell. The regional methods are used to reduce the influence of boundary conditions on the upscaling result.

Global Methods: All flow cells are upscaled simultaneously by computing the complete pressure field of the geo-model and performing a

'history match' for the coarse cell properties. The method requires a flow simulation performed on the geo-grid.

8.2.6 Sampling for Upscaling

Sampling is a pre-processing step for the upscaling and is time consuming and error prone. Selection of the correct sampling method will significantly influence the upscaled result. Reduction of sampling errors is an important goal both for geo-grid design and simulation-grid design.

The sampling method selected may influence the upscaled result significantly!

8.2.6.1 Sampling Errors and Problems

The sampling problem consists of finding representative values from the geological grid located inside a cell in the simulation grid. This includes defining the correct volume associated with each fine cell inside the coarse cell.

It is especially important to focus on sampling problems for fluvial reservoirs, where channel belts in the geological model may have a width close to the length scale used by the simulation model. For these reservoirs, the geological grid and the simulation grid should be designed with as much correspondence as possible, by using the SmartModel concept described earlier.

The sampling process is rather time consuming. If possible, several properties should be upscaled simultaneously, using the same sampling process.

8.2.7 Sampling Methods Overview

Two common methods for sampling are commonly defined (Figure 8.11):

- Re-sampling.
- Direct sampling

In re-sampling, the simulation grid cell is divided into a finer grid with a specified resolution. Each finer grid cell is assigned the property value that the geological model has at the centre of the fine cell. The sampling error will decrease as the sampling resolution increases, but so will the calculation time. It is recommended to have a resolution of no less than four cells for the flow-based upscaling methods.

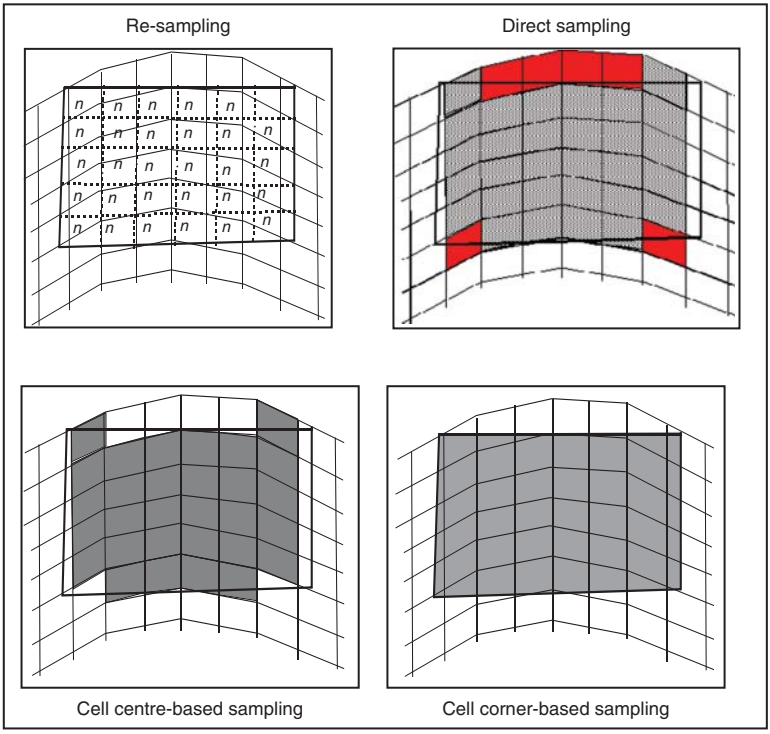


Figure 8.11 A comparison of resampling and direct sampling methods for cell centre-based and corner-based methods. *Source*: Reproduced with permission of Emerson-Roxar.

The simulation grid cell is assigned cells from the geological model in direct sampling. In most software, there are again two different methods:

- Cell centre based
- Cell corner based

For the cell centre-based method, the geological grid cells with their centre position inside the simulation grid cell are assigned to that cell. For renormalization and the flow-based upscaling methods, the smallest box of geo-model grid cells containing the cell centre-based cells is used. Only the part of the geo-model grid cells that is inside is used for cell corner based method.

The cell corner-based method can be time consuming if the number of truncated geo-grid cells is large. The method is only available for some of the statistical averages.

8.2.7.1 Selection of Sampling Method

Re-sampling is generally faster than direct sampling, but the sampling error may be significant if there is complex grid geometry or different grid orientations between the simulation model and the geo-model. Generally, it is recommended to use direct sampling. Exceptions from this are:

- When upscaling with renormalization. Direct sampling will fail if the dimension of the sampling grid is not a power of 2.
- When the simulation model and the geo-model are perfectly aligned and have proportional dimension.

Sampling errors are reduced if a correspondence between sets of layers in the geological model and a layer in the simulation model can be specified. This is called *layered sampling* and should be used whenever possible.

If layered sampling cannot be used, cell corner-based direct sampling should be preferred if possible.

8.2.8 Upscaling Porosity

The porosity is a volumetric property, and the purpose of upscaling is to create a representation of the pore volume distribution found in the geocellular model. Using a simple bulk volume-weighted arithmetic upscaling for the porosity does this.

Note that if the geocellular model includes a net/gross distribution, the effective porosity should be first calculated and used as basis for upscaling.

8.2.9 Upscaling Permeability

Upscaling of the permeability is especially difficult as the permeability is a non-additive property. A lot of possible techniques exist, and the results from these techniques can vary significantly. It is generally difficult to decide which method is best for a given model.

When the areal resolution of the geo-grid and the simulation grid is the same, the upscaling is only carried out in the vertical direction. This is often the case for fluvial reservoirs. Then the arithmetic and

harmonic average should be used for the horizontal and vertical permeability, respectively.

Use arithmetic average for the horizontal permeability and harmonic average for the vertical permeability when the areal resolution is the same for the geo-grid and the simulation grid.

Simple averaging techniques are less time consuming than flow-based upscaling, and for many purposes, these methods will suffice. This includes, for instance, when upscaling is a part of a model-ranking process. Static techniques can also be sufficient for simpler models, for instance for map-type models having only a single grid layer in each zone.

A good choice for a simple averaging method is to use arithmetic–harmonic average for the horizontal permeability and harmonic–arithmetic average for the vertical permeability. For more complex geo-models where it is important to conserve structure from the geo-model into the flow model, flow-based upscaling is recommended.

If two alternative upscaled values are generated, using the no-flow and linear boundary conditions, respectively, a lower and an upper bound of the permeability are defined. If the two distributions in some sense are close, a representative effective permeability distribution is found, and you can use any of the two. If significant differences between the two generated distributions exist, you will have to decide which element of the reservoir's performance is the most important and choose the boundary condition that preserves these flow characteristics.

The no-flow boundary conditions reduce the permeability of a sand and mud mixture, make shales thicker and make channels more narrow and disconnected. The method is however very good at including the effect of barriers. If there is a horizontal barrier, there will be no vertical flow in the grid cell. With linear boundary conditions, streamlines can enter and leave every boundary, so there will be a flow around the barriers.

If a barrier exists over a horizontal well and the productivity of the well is to be evaluated, linear boundary conditions are better for assessing the vertical permeability. On the other hand, if the potential for gas coning down to this well is to be evaluated, a vertical flow barrier may be preferable.

8.2.10 Upscaling Net/Gross

There are several reasons why the net:gross ratio should not be upscaled as an individual entity:

- Net/gross is treated both as a volumetric property and as a (horizontal) flow property in the simulations. The upscaling cannot account for both these properties.
- The net/gross is used as a multiplier when calculating pore volumes and transmissibility factors. A product of two quantities cannot be averaged individually to achieve the average of the product.

To handle net/gross in upscaling, the quantity should be multiplied into the porosity and the horizontal permeability in the geological model before upscaling, thus performing the homogenization on the effective values.

Note that vertical permeability is not affected by the net:gross ratio. This requires that the K_v is the true effective value for the cell, not only the net sand value. If it is desirable to have an upscaled porosity that is not affected by the net:gross ratio in the model, the following relationships can be used for the net:gross ratio and the horizontal permeability.

$$\overline{NTG} = \frac{\overline{\emptyset \cdot NTG}}{\overline{\emptyset}}$$

$$\overline{K_H} = \frac{\overline{K_H \cdot NTG}}{\overline{NTG}}$$

8.2.11 Water Saturation Modelling

The water saturation modelling for the simulation model has several objectives:

- Correct volumetric representation.
- Correct representation of end-point saturation values for relative permeability and capillary pressure curves.
- Correct representation of mobile and immobile fluids in the transition zone.
- A numerically stable model without spurious fluxes.

A common experience from many fields is that the water found in the 'transition zone' is not producible. This is not in accordance with a capillary pressure model, where the water should be moveable even for reasonable pressure gradients. The water transition zone is probably influenced by upwards and downwards moving fluid level over geological time, creating a combination of drainage and imbibition effects that cannot easily be explained by a single capillary curve. The capillary pressure curve is basically dependent on scale and should ideally be upscaled from the core plug level to reservoir level.

If the J-curves defined by geology yield a reasonable volume representation when used directly in the simulation model, this simplification could be used as a pragmatic approach. J-curves or capillary pressure curves can give the best model for the influence of heterogeneities on tail production. The flow in the transition zone will also be represented more correctly.

8.2.12 Quality Control

While comparing the results, remember that the upscaled properties on the simulation model could have been affected by the net:gross ratio and/or have been weighted with some volumes.

- Check min/max and histogram distribution between geo-grid and simulation grid for porosity, permeability and $k_V = k_h$.
- Check pore volume and fluid volumes in defined regions and zones for geo-model and simulation model.

8.2.12.1 Control of Well Data

Data from both the geo-model and the upscaled model can be compared with the original data from the well logs. However, in the comparison, remember that the upscaled properties in the wells in the simulation model also include information from the geo-model outside the wells.

8.2.12.2 Use of Streamlines

Streamline simulation can be used for testing the validity of an upscaling. Streamlines produced using the geo-model can then be compared with streamlines from the upscaled model, to see if main features of the geo-model have been conserved in the upscaling. The streamline simulator can be especially useful for fluvial reservoirs, to see if channel communication characteristics are preserved in the upscaling.

The results from the streamline simulator should only be used for comparison purposes and can never replace a traditional numerical simulation for production forecasts. Time estimates given by the streamline simulator have nothing to do with physical time and should again only be regarded as relative estimates.

The results from the streamline simulations quickly tend to be messy and difficult to interpret. To be able to analyse the results, it is critical to select a simple artificial well pattern in the simulations. Use a set containing only a few injectors and producers.

8.3 Work Flow Specification

This section specifies data and tasks involved when defining property data for the reservoir simulation model. This involves flow properties for simulation grid cells and cell boundaries. As for the simulation grid data, property data should be documented fully:

- Upscaled cell values for porosity and permeability.
- Upscaled cell values for shale volume if that is being used for net to gross estimation.
- Upscaled cell values for water saturation.
- Transmissibility multipliers for faults.
- Transmissibility multipliers representing restrictions to vertical flow.
- Formation compressibility.

8.3.1 Upscaling Workflow

The sampling part of upscaling is critical for the final result. The sampling depends heavily on the relationship between the geological grid and the simulation grid, and this aspect must be taken into account when the two grids are designed.

- Select upscaling methods.
  - Use pore volume-weighted arithmetic average for porosity.
  - For permeability, general rules are not easily given, as methods must be based on flow characteristics. For ranking purposes, simple methods as statistical averages should be used. In many cases, a flow-based upscaling is preferable for flow simulations.
  - For water saturation, two alternative methods are described in the section on property modelling. The first method is based on using the J-curves defined as part of the property analysis workflow, the second method uses upscaling of the water saturation distribution in the geo-model, with a pore volume-weighted arithmetic average.
- Select sampling method
  - Direct sampling is usually preferable, although more time consuming. If correspondence between geo-layers and simulation layers is used, as recommended in the simulation grid design, then layered sampling should be applied. If this is not the case, a volumetric weighted averaging technique should be used.

- Following an upscaling of effective porosity, a volume control must be performed as described in the previous chapter Volumetrics.
- If the end-point scaling option is used for water saturation, define water saturation table data.
- When the water saturation model has been defined, fluid volumes can be compared with the geo-model, again refer to Chapter 7 (Volumetrics and Uncertainty).
- Calculate transmissibility multipliers for faults represented in the simulation grid using a fault multiplier.
- If effects of small sub-seismic faults are to be represented in the model, an updated permeability field should be calculated, accounting for faults not represented in the grid.
- Define transmissibility multipliers for zone boundaries.

8.4 Summary

Upscaling is the final challenge in the static reservoir modelling process and one that I believe should be done by the reservoir engineers!

9

Case Studies and Examples

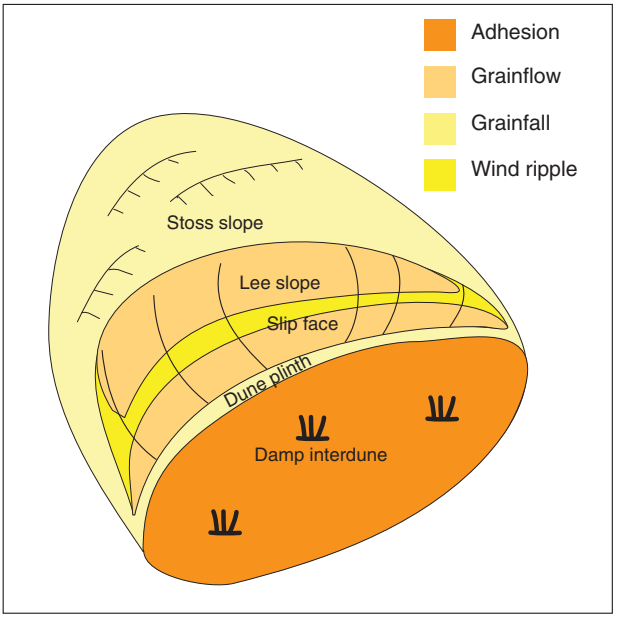
In this chapter, it is my intention to look at a number of depositional environments and suggest how best they may be modelled. Some of these will be adapted from published literature and others will be from personal experience. I will also address some of the uncertainty modelling examples that are available as software sales literature. I strongly suggest that you acquire a copy of Facies Models Revisited, SEPM Special Publication (No. 84) (Posamentier and Walker, 2006) to help with the ideas about different depositional environments and what it is you are trying to model.

9.1 Aeolian Environments (Figure 9.1)

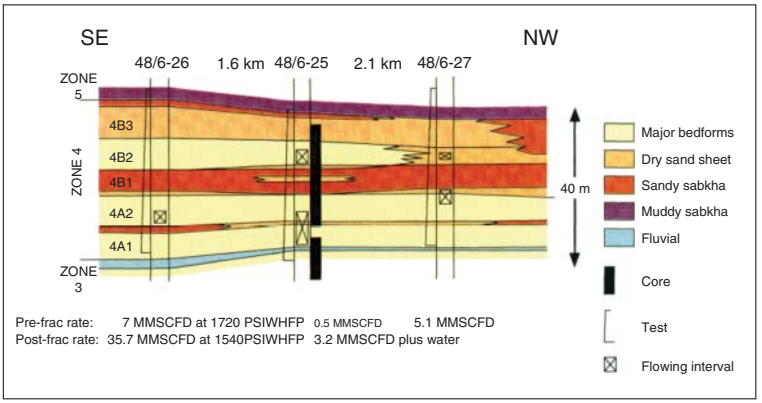
An excellent example of modelling a low-permeability aeolian gas field is the study on the Hyde Field in the Southern North Sea located in blocks 48/6, 47/10, 47/5a and 48/1 (Sweet *et al*., 1996). The field was developed using three extended reach horizontal wells targeting reserves of 133 Gcf. The structure is a weak anticline associated with inversion during the Alpine Orogeny, and the current depth of the reservoir is ~2900 m. Given the low relief and relatively thin nature of the reservoir interval (~125 m), the gas was thought to be in 'transition zone'. The field comprises stacked mixed fluvial and aeolian sands of Permian age that form the Rotliegend gas-bearing fields in this region. In many fields, deeper burial during the Jurassic resulted in the precipitation of illite cements that significantly reduce permeability.

In the study, the field was divided into three units, Alpha, Beta and Gamma, based on regional stratigraphic data that indicated a number of wet and dry periods when the basinal Silver Pit Lake expanded

Reservoir Modelling: A Practical Guide, First Edition. Steve Cannon.



(a)



(b)

Figure 9.1 (a) A schematic aeolian dune form showing the different elements of deposition each with potential different reservoir properties that might require rock typing and separate property distributions. *Source*: Mountney (2006). (b) The Hyde Field lithostratigraphy. *Source*: Steele *et al*. (1993). Copyright 1993, Geological Society of London.

or retreated resulting in variation in the water table. The data for the model came from eight offset wells that included core and wireline log information; no seismic attribute data were available. The units were modelled separately and then recombined for full field simulation of future gas production.

The Rotliegend Group in the Hyde Field is ~200 m thick; however, the upper 75 m comprises non-reservoir Silver Pit Formation and was not modelled. In the remaining 125 m, five facies were identified: muddy sabkha, sandy sabkha, aeolian sandsheet, aeolian dune and fluvial sands. Of these facies, the aeolian dune sands form the main reservoir units. The proportions of each facies varied sufficiently in each unit to warrant modelling separately (Figure 9.1b).

The Alpha unit (Zone 1) is at the base of the sequence and comprises predominantly aeolian sands (~90%) and fluvial sands (~10%). The Beta unit (Zone 2) comprises a more mixed facies distribution including sabkha, sandsheet, dune sands and fluvial sands. The upper interval, Gamma (Zone 3), comprises the same facies but shows an upward decrease in aeolian sands as the Silver Pit lake expanded and the water table rose. Additionally, there is predominance of sandy sabkha facies in the north of the field: all of these vertical and lateral trends were captured in the model (Table 9.1). A brief description of each facies follows:

- *Muddy sabkha*: Characterized by very fine-fine grained sand interbedded with discontinuous muddy laminae resulting in an intensely mottled texture.
- *Sandy sabkha*: Comprises a similarly mottled texture but with significantly more sand and <10% interstitial clay.

Table 9.1 Distribution of facies by reservoir zones from core and log data; these form targets for modelling.

Facies/unit (Zone)	Muddy Sabkha (%)	Sandy Sabkha (%)	Aeolian sandsheet	Aeolian dune (%)	Fluvial (%)
Gamma (3)	0.5	34.5	43.3	21.7	0.0
Beta (2)	0.0	7.4	6.9	83.0	2.7
Alpha (1)	0.0	0.0	0.0	91.6	8.4
Total	<0.5	14.0	17.7	65.4	3.7

Source: Sweet *et al.* (1996). Copyright 1996, American Association of Petroleum Geologists.

- *Aeolian sandsheet*: Composed of a mixture of thin grain flows (<1 m) and wind ripple laminations that exhibit a strongly bimodal grain size distribution.
- *Aeolian dune*: Consists of 0.5–3 m-thick sets of cross-bedded, fine- to medium-grained sands representing dune toe-sets and grain flows associated with simple crescent-shaped dunes.
- *Fluvial facies*: Occur as 1–8 m-thick largely poorly sorted, structureless sands exhibiting water escape features; there is a significant proportion of admixed clay and silt that reduces reservoir quality.

9.1.1 Building the Model

In 1996, no commercial reservoir modelling software products were available; companies were using SIS and SGS algorithms from the academic GSLIB toolbox developed by Stanford University (Deutsch and Journel, 1992). In this case, BP adapted the routines to better suit their needs.

Each zone was modelled as a rectangular box of dimensions 8500 m × 5500 m × 125 m oriented along an E–W axis. The cells were 50 × 50 m in x and y directions and ~0.5–1.0 m thick: Zone 1 (Alpha) comprised 56 layers, Zone 2 (Beta) 32 layers and Zone 3 (Gamma) 30 layers. Each zone was model with constant layers and rescaled for geostatistical modelling in a Cartesian grid (Simbox).

Modelling took place in two stages; firstly, distributing the facies across the field using SIS and honouring the different proportions in each unit and at the wells and secondly using SGS to populate the large-scale facies architecture with properties. Porosity and permeability ranges for each facies in each zone were determined from core data in the offset wells. Building and upscaling fine-scale, 3D permeability models of each facies accounted for the spatial distribution of permeability. All permeability upscaling was done using a pressure solver technique.

Variogram analysis of the well data generates the vertical spatial distribution of facies and permeability. However, insufficient data points precluded the construction of variograms in the x and y or major and minor directions. To understand the lateral distribution of facies, outcrop analogues were studied to give some control of the scale of each facies in terms of length, width and thickness (Crabaugh and Kocurek, 1993).

The Alpha unit is dominated by aeolian sand dune facies, with an increase in fluvial facies towards the top; the well data successfully captures this distribution, thus eliminating the need for a specific vertical trend. The Beta unit is dived into three sub-zones based on the presence of a regionally extensive highstand sabkha unit in the middle; the upper and lower sub-zones are wholly populated with aeolian dune sand. The Gamma unit was modelled as a four-component system using a type of indicator simulation with external drift to capture the N–S trend in facies. A number of detailed trends and distributions were included in the model to try and capture the conceptual facies models developed by the geologist; to some extent, this was hand-building the model.

Modelling porosity was straightforward using effectively a TPM approach; all facies were considered net reservoir with NTG = 1. Much more effort was made to model permeability including the construction of fine-scale models of aeolian dune and sandsheet packages that show a significant element of horizontal layering; a permeability anisotropy ratio of 5:5:1 (*x:y:z*) was modelled based on outcrop studies. Cells in the fine-scale model had dimensions of $50 \times 50 \times 10$ cm and the whole model was $50 \times 50 \times 10$ m, being 10 times bigger than a cell in the facies model. SGS was used to distribute permeability in each direction assigning K_h and K_v values to each cell. In the fine-scale model, the aeolian dune sets were modelled as trough cross-bedded packages with bounding surfaces dipping at 2° and the cross-strata dipping at 30°, with permeability greatest at the base. The model was then upscaled using a single-phase pressure solver using the 3D effective permeability values generated from the finest scale model.

As a final step in the workflow, the model was tested against dynamic data from the producing wells attempting to match deliverability, material balance and gas rates. A number of reservoir engineering parameters were used to fine-tune (manipulate or fudge) the results to achieve a good history match; however, the detailed modelling improved the ability of the operator to predict production from the field.

9.1.2 Remodelling

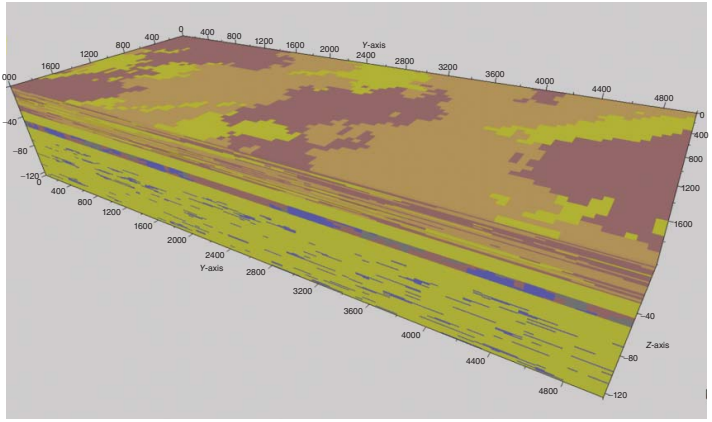
How might you build a model of this field today given the 20 years of development in geostatistical modelling? And can you still match the

results of the property modelling? Not having access to the actual well data, I can only propose the following workflow:

1. Build a rectangular grid of the same proportions as the original model (8500 × 5500 × 125 m) divided into three zones with a grid dimension of 50 × 50 m and cells 0.5 m and 1 m thick in the appropriate zones to create the layering.
2. Subdivide Zone 2 into three sub-grids to accommodate the high-stand sequence as described.
3. Populate each zone or sub-zone using an indicator simulation method to honour the facies proportions as seen in the wells (Table 9.1). For Zone 3, try the TGSim algorithm to replicate the trend of increasing muddy sabkha to the north. A vertical proportion curve might help with distributing the facies; the vertical variogram information might help here.
4. I might try to build a dune-shaped object and try to model the aeolian sands using this approach, rather than sticking to SIS (Figure 9.2).
5. I do not think I would build the fine-scale permeability model at this stage but would try and use the available data to create a simple property model. Trusting Flora's Law, this is a gas field with only 1–2 orders of magnitude difference in permeability between the facies. The challenge of producing dry gas from horizontal wells in this field might ultimately require it, but the introduction of a small-scale heterogeneity through a facies model might achieve the same result.
6. We are unable to compare the in-place volumes, as we do not have a saturation model or a top structure map.

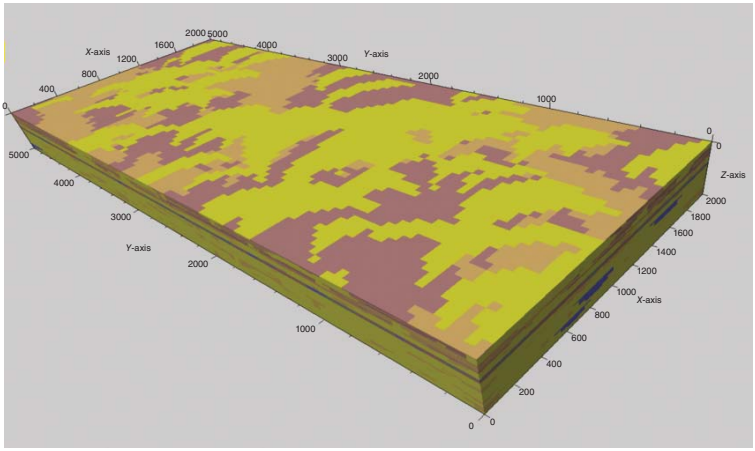
9.2 Alluvial Environments (Figure 9.3)

An alluvial system is one in which the river bed and banks are made up of mobile sediment and soils; the channels are shaped by the magnitude and frequency of the floods they experience that erode, deposit and transport sediment. Thus, alluvial rivers can assume a number of forms including braided, anastomosing, and sinuous or meandering dependent on the gradient, flow regime and volume of sediment they carry. The vegetation surrounding the channel system impacts on the preservation potential of each channel and the trapping of sediment, leading to soil formation.



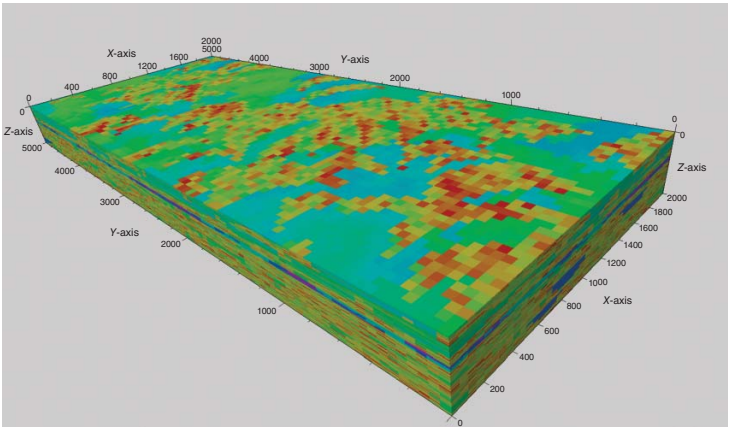
(a)

Figure 9.2 (a) SIS facies model of the Hyde Field based on the description in Sweet *et al*. (1996). (See Figure 9.1b for facies description and colours.) *Source*: Sweet *et al*. (1996). Copyright 1996, American Association of Petroleum Geologists. (b) Facies model of the Hyde Field using dune-shaped objects distributed in the upper zone; the other zones modelled using SIS. (c) Porosity model of the Hyde Field using SGS; note that the dune forms are retained. Vertical heterogeneity within the dunes can also be modelled using a simple function.



(b)

Figure 9.2 (*Continued*)



(c)

Figure 9.2 (*Continued*)

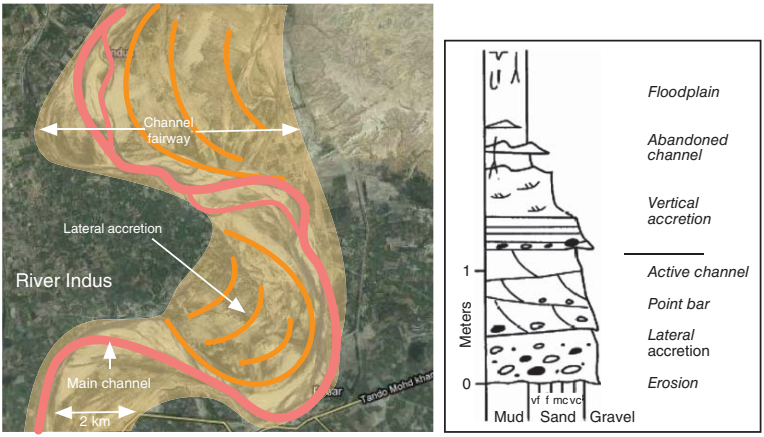


Figure 9.3 (a) An annotated map of the River Indus picking out the major channel forming features of a high-energy, seasonal fluvial system. (b) A low-sinuosity, low-NTG fluvial system (sand volume ~ 25%) with attached levee deposits. (c) Individual channel bodies are picked out as isolated bodies; only the pink-coloured bodies are well connected.

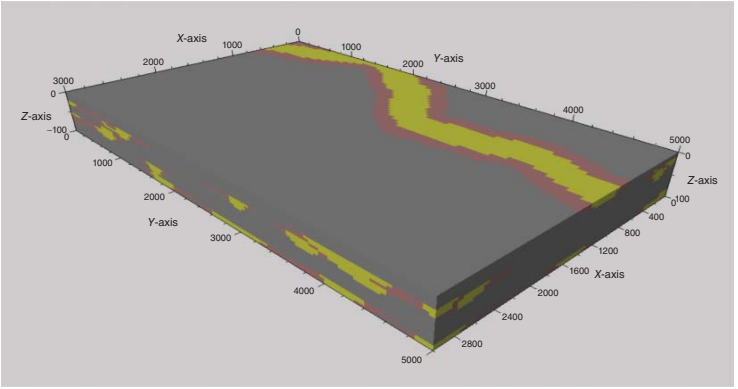
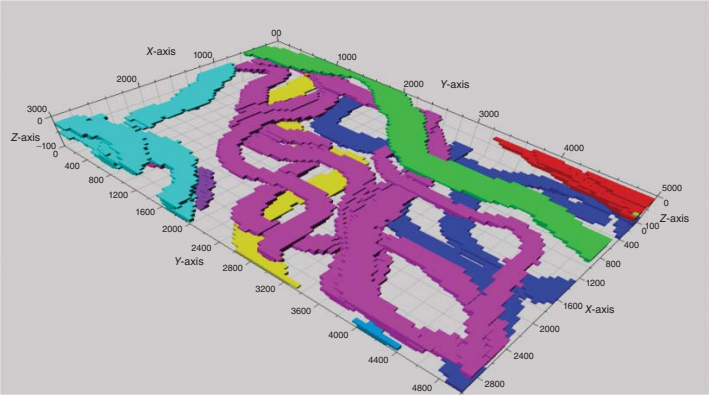


Figure 9.3 (*Continued*)



(c)

Figure 9.3 (*Continued*)

Straight channels (sinuosity < 1.3) are relatively rare in natural systems due to the fact that sediment and flow are rarely distributed evenly across a landscape. Irregularities in the deposition and erosion of sediments lead to the formation of alternate bars on opposite sides of the channel in succession. Alternating bar sequences result in flow being directed in a sinuous pattern, leading to the formation of sinuous channels (sinuosity of 1.3–1.5).

Meandering channels are more sinuous (>1.5 sinuosity) than straight or sinuous channels and are defined by the meander wavelength. The meander wavelength is the distance from the apex of one bend to the next on the same side of the channel. Modern meandering channels are widespread, their preservation largely due to the effect of vegetation in increasing bank stability and maintaining meander formation.

Multiple, active streams within a broad, low-sinuosity channel fairway characterize braided channels. The smaller strands of streams diverge around sediment bars and then converge in a braiding pattern. Braided channels are dynamic, with strands moving within the channel. Sediment loads that exceed the capacity of stream transport cause the formation of braided channels. They are found downstream of glaciers and mountain slopes in conditions of high slope, variable discharge and high loads of coarse sediment.

Anastomosing channels are similar to braided channels in that they are composed of complex strands that diverge and then converge downstream. However, anastomosing channels are distinct from braided channels in that they flow around relatively stable, typically vegetated islands. They also have generally lower gradients, are narrower and deeper, and have more permanent strands.

Part of a developed alluvial system will be the floodplains, natural levees and river terraces; all the three represent landforms that can trap and store sediment that escapes form the main channel during a flood or channel breach (Figure 9.3a). Channels will migrate over time through a process of channel capture and avulsion often resulting in the formation of oxbow lakes or abandoned meanders.

When characterizing the type of alluvial system you plan to model, it is worth distinguishing between high-stage low (flood) sediments and low-stage flow in the main channel; the former tends to be coarser and may have better reservoir quality. During flood, the river may escape the channel boundaries and deposit fine sediment across the flood plain as sheet-like or lobe-like splays; these may act as conduits of flow in a reservoir, albeit of lower reservoir quality.

9.2.1 Building the Model

The first thing to do is to draw the alluvial environment you believe is represented by the sedimentological data available. A high proportion of floodplain sediments tend to lead you towards sinuous or meandering systems; coarse-grained sands and gravel may indicate high flow regimes and braided or anastomosing environments. It may be that modelling a wide fluvial fairway containing individual channels is the way to go or try to establish rock types and distribute these randomly within the fairway when you have less information about channel morphology.

Fortunately, most software packages have tools to model channel objects; remember only object modelling creates connectivity implicitly (Figure 9.3b). To successfully model one of the alluvial systems, you need information about the width and thickness of the channel body or fluvial fairway, as well as some idea of the wavelength and amplitude of the channel form; this information is usually only available from analogue or outcrop data. There is much published literature from the 1980 to 1990s where post-graduate students have taken measurements of the scale and size of river systems, but bear in mind that these should only be used as a guide. I find that Googlemaps is an excellent place to find geomorphological information of different modern depositional environments: 'the present is the key to the past'.

Essentially, you are trying to model a channel/fairway within a floodplain, but bear in mind that our data points (wells) may be focussed only on the channels; who wants to drill in the low-quality stuff? In the past, this has come back to haunt many a development geologist. My go to solution is to build a floodplain model with SIS and to use that as the background to a system of channel objects, perhaps confined to a fairway or allowed to spread across the whole model (see Figures 5.10 and 5.11). There are usually ways to specify channel entry points and to change the width of the channel belt. If high-quality seismic is available, you can extract a geo-body and use that to condition the model.

How can you tell whether your model is representative of the reservoir? Well, first of all, 'does it look right?' Then, look at connected volumes; are the channels isolated or do the merge into a single body? Do the better floodplain sediments provide connection between the channels increasing the overall in-place volumes? From a study on percolation theory (King, 1990) based on overlapping sand bodies, a NTG of around 25% would indicate that most would be

somehow connected in 3D, although the paths could be quite tortuous (Figure 9.3c).

9.3 Deltaic Environments (Figure 9.4)

First catch your delta; what type of delta are you trying to model and where does your field sit in the overall environment? Deltas are traditionally described as a tripartite classification: fluvial, tidal and wave dominated, but there are many other sub-classes that have been described over time. Indeed, most deltas probably go through a number of stages during which different processes are dominant. Deltas make up some of the most important and prolific hydrocarbon provinces in the world, including the Mississippi Delta, Niger River Delta, Nile River Delta and Baram Delta.

The ancient example of a deltaic environment and one for which channel object modelling was developed is the Middle Jurassic Brent Group in the Northern North Sea (Cannon *et al*., 1992). The progradational sequence goes from lower-upper shoreface and beach barrier, followed by lagoonal and delta top environments, before the delta was drowned in a series of transgressive events. The first conceptual model of the system (Figure 9.4a) was published in 1981 (Budding and Inglin) based on the South Cormorant Field but has been applied in part to most occurrences of Brent Group sediments (Figure 9.4b). The strongly correlated sequences lead initially to a layer-cake stratigraphy (Deegan and Scull, 1977), but with the advent of sequence stratigraphic ideas, a different approach was developed for correlation (see Figure 4.2).

The Brent sequence can be divided into three substantially different depositional packages (zones), each of which can be modelled using different approaches and methods. The key to defining the zones is a consistent correlation scheme.

- *Rannoch–Etive*: A progradational shoreface sequence building from S–N as a series of inter-fingering parasequences of very fine- to medium-grained sands. Locally, there is some erosion by tidal channels and development of carbonate nodules: these features can have a big impact on flow in the local well area but are difficult model without well test information.
- *Ness*: A mixture of lagoonal, delta plain and fluvial packages progrades behind the barrier and is occasionally flooded by marine

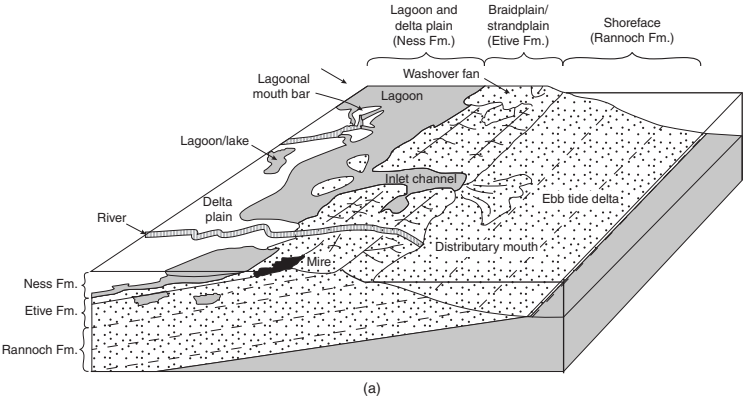
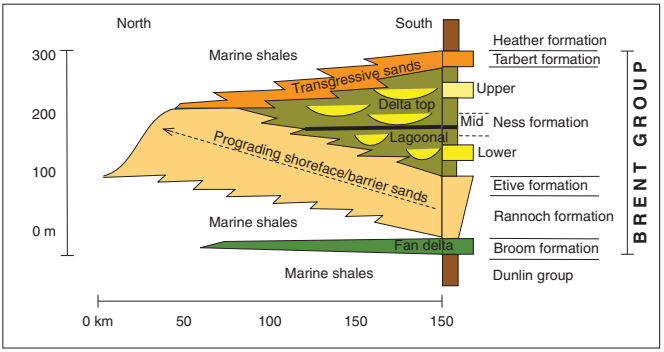


Figure 9.4 (a) The Brent Field conceptual model, based on the South Cormorant Field, UK North Sea. *Source*: Budding and Inglin (1981). Copyright 1981. (b) Brent Group regional stratigraphy. *Source*: Deegan and Scull (1977). Copyright 1977.



(b)

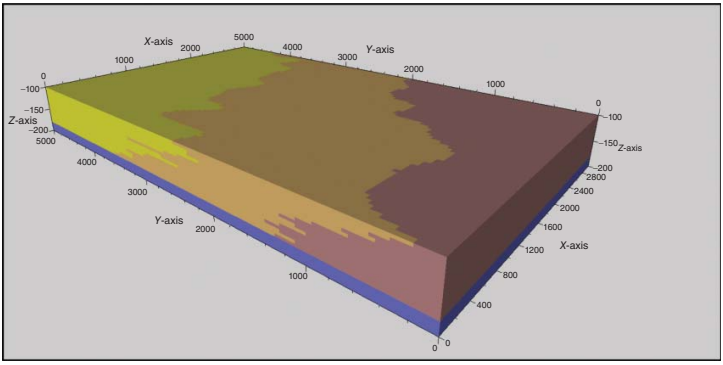
Figure 9.4 (*Continued*)

waters as the sea level rises and falls mostly due to auto-cyclicity. A major flooding event is recorded across the delta, the Mid-Ness shale, above and below which the style and number of channel sands vary.
- *Tarbert*: the transgressive sands infill and erode the existing Ness topography as the sea level rises inexorably and floods the delta.

9.3.1 Building the Model

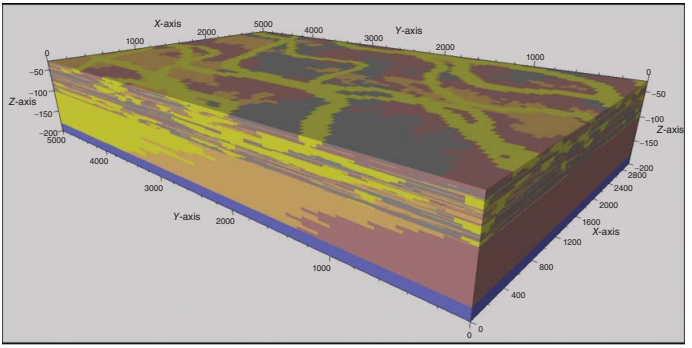
To start with, draw the part of the overall deltaic package you are trying to model; your field may only show elements of the sequence. In the case of the Brent Group, this might be an acceptable workflow.

1. Zone 1 can be modelled using a Truncated Gaussian Simulation (TGSim) with trends: this method captures the progradational nature of the shoreface package as a series of belts (Figure 9.5a). In effect, we are modelling a shallow marine environment and we will look at that in more detail later. The best-quality sands will be found in the high-energy barrier sands at the top of the sequence, although these may be eroded, cut through by channels or repeated. Any cemented nodules can be generated as objects with proportions equivalent to a single cell; they are there to act as potential baffles to flow and to represent a loss of pore volume.
2. Zone 2 comprises lagoon, delta top and channels, ideally suited for a composite model where the lagoon and delta top sediments are modelled using sequential indicator simulation and the channels as objects (Figure 9.5b). The lagoonal deposits are laterally extensive and will possibly be oriented parallel to the barrier requiring a variogram with very different major and minor ranges. Other facies that might be included are coals, which may be used to subdivide the zone if required and lagoonal deltas and crevasse splay deposits; these might be cone-shaped objects or treated as another facies in the overall delta top environment and included in the SIS model.
3. Zone 3 can be a challenge to model because it is likely to contain discontinuous transgressive sands overlain by deeper marine shales. Sometimes, the discontinuous character of the zone is captured in the grid building and sometimes by subdivision of the zone. As we are usually only modelling one facies change, reservoir quality can be captured by rock typing if necessary. In this case (Figure 9.5c), I have used SIS with marked N–S orientation to the variogram to capture the infill of palaeotopography by transgressive deposits.



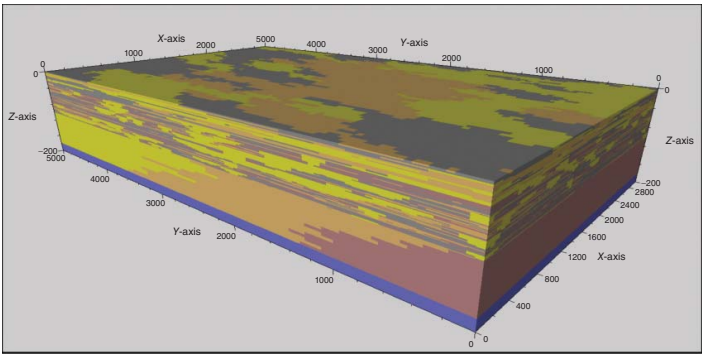
(a)

Figure 9.5 These three images show how a complex deposition system like the Brent Group can be constructed in stages; (a) the use of TGSim to model facies belts representing the Rannoch–Etive sequence. The basal Broom package is in blue; (b) the use of channel objects modelled in a background of floodplain deposits created by indicator simulation; (c) the Tarbert interval is built using an SIS algorithm with a strongly N–S major direction.



(b)

Figure 9.5 (*Continued*)



(c)

Figure 9.5 (*Continued*)

9.4 Shallow Marine Environment (Figure 9.6)

Shallow marine deposition takes place below wave base and results in predictable progradational and retrogradational packages of generally silty, very fine sandstones and fine sandstones, with occasional layers of heavy minerals and coarse-grained granule lags (Figure 9.6a and b). Other common lithologies include carbonate nodules and layers often associated with concentrations of calcareous shelly debris. As the sequences are predictable, they can easily be modelled with TGSim creating belts of upward coarsening and fining sequences, often with a sequence boundary marked by the lag deposits.

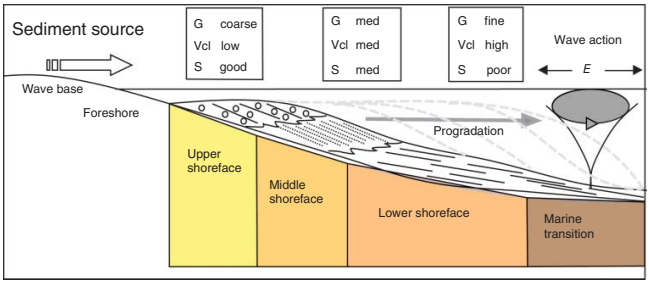
The Upper Jurassic Fulmar Formation in the North Sea is characterized by a bow-shaped sequence often following thin, blocky, transgressive glauconitic sandstones (Figure 9.6c). The complete sequence, where preserved, comprises very-fine to fine argillaceous sandstone, often with the variably thick blocky unit of less argillaceous, high-energy sandstone. The trace fossil assemblage present in each of these units describes an increase in depositional energy as the relative sea level falls (Cannon and Gowland, 1996).

Shallow marine deposits of this type also show a very predictable link between clay content and reservoir quality; the lower energy silty sandstones from the marine transition zone have lower porosity and permeability than the higher energy middle shoreface sandstones. Although upper shoreface sandstones are preserved, they often show a better poro–perm relationship to the other sands (Figure 9.6d). If it is possible to demonstrate that these better-quality sands form distinct shoal-type bodies, it may warrant a composite model where lozenge-shaped objects are inserted into the background model of shoreface sands.

9.4.1 Building the Model

The number of zones required to build the model will depend on the number of individual sequences you need to model and their nature: progradational, aggradational or retrogradational. A single zone with well-defined inter-fingering may be sufficient for the Rannoch–Etive sequence, but multiple stacked parasequences encountered in the Baram Delta would require multiple zones.

For a Fulmar Formation sequence, the following workflow should suffice:



(a)

Figure 9.6 (a) Shallow marine deposition takes place below wave base and results in a gradual progradation from upper shoreface to marine transition with a predictable change in grain size, sorting and clay content; (b) this is reflected in the upward coarsening profile and in the case of the Fulmar Formation, UK North Sea, a classical bow-shaped log profile; (c) these predictable characteristic are reflected in the poro–perm cross-plot, (d) where the higher energy shoreface deposit forms a separate cluster of data.

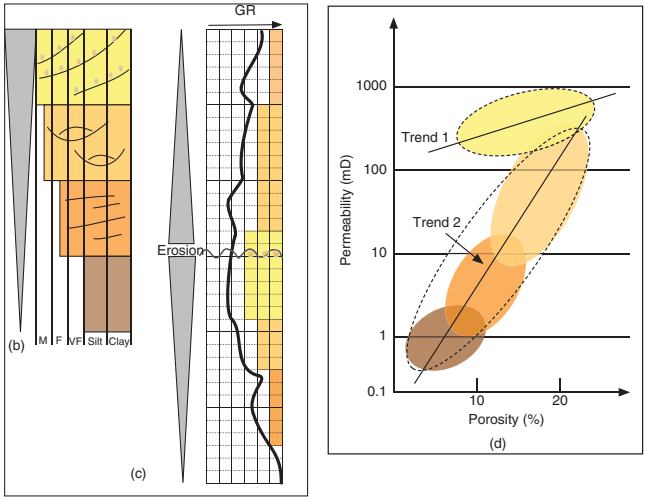


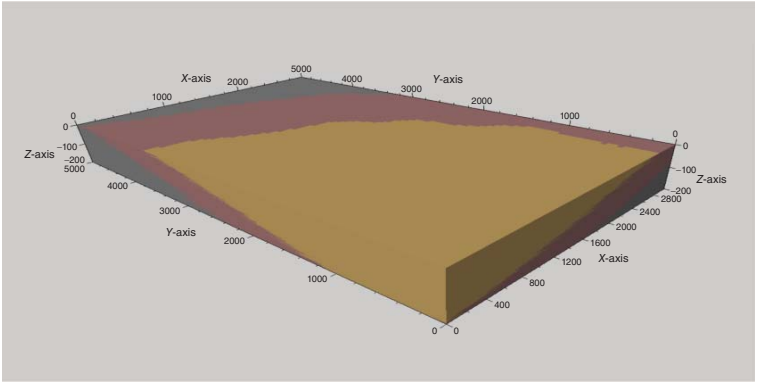
Figure 9.6 (*Continued*)

1. First, draw the conceptual model.
2. Build two separate zones, a lower zone to be populated with the progradational sequence and the upper zone for the retrogradational package. If there is a transgressive package at the base, this is likely to have a patchy distribution and well control may be sufficient to build this without the need for a vertical trend.
3. Next, using the TGSim algorithm that includes a trend option, decide on the orientation of the shoreline and also the angle of aggradation or slope of the seabed, this is generally around 3–6° (Figure 9.7a). Fiddling about with the variogram settings and the facies boundaries will help with distribution.
4. Repeat the process for the retrogradational sequence to achieve backward-stepping belts of sediment.
5. If you need to model separate shoal bodies of better-quality rock, then you must know the size, shape and orientation (Figure 9.7b). Analogue data for outcrop are possibly the best source for this information, and if there are pressure data from appraisal wells in the field, they may give some indication of connectivity and hence spacing: use all the information available.
6. Populating the model with properties is the next step (Figure 9.7c). If you have sufficient core and log data, it is possible to build a robust porosity and permeability relationship to use. As the sediments represent a depositional continuum in the main, then a single distribution for each package should be enough, with a second distribution used for the better-quality shoal bodies.

9.5 Deepwater Environments (Figure 9.8)

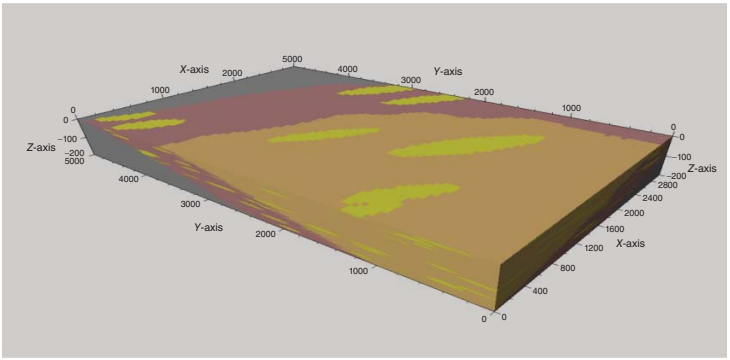
There are many deepwater depositional environments and they are not all turbidites; for that matter, not all turbidites are deepwater! If we imagine a typical deepwater depositional model (Figure 9.8), then we think of a channel in the shelf break down which sediments are funnelled in the deeper water and deposited on the seafloor as lobes and mounds that are often channelized. This type of model will give a predictable depositional sequence to model. Individual depositional events may show the classical Bouma vertical sequence of facies (Figure 9.8b) that may result in variable rock properties.

An example of a deepwater reservoir model can be found in the Hamitabat Field, Thrace Basin (Conybeare *et al.*, 2004). The field has



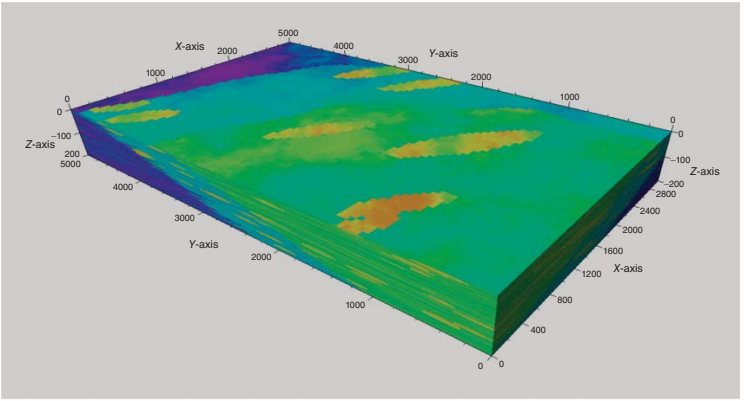
(a)

Figure 9.7 Examples of shallow marine models; (a) progradation sequence of fine sands, very fine sands and argillaceous sands modelled with TGSim to create belts; (b) additional high-energy clean shoal sands models as objects with strong linear orientation; (c) porosity model using SGS to distribute facies-specific ranges in porosity between 0.01 and 0.30 p.u.



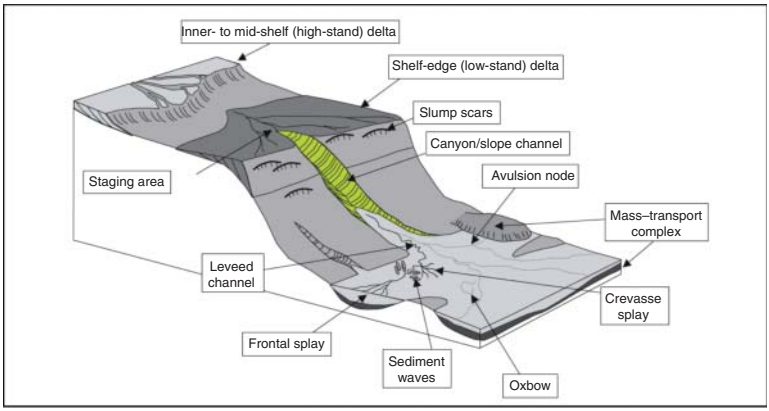
(b)

Figure 9.7 (*Continued*)

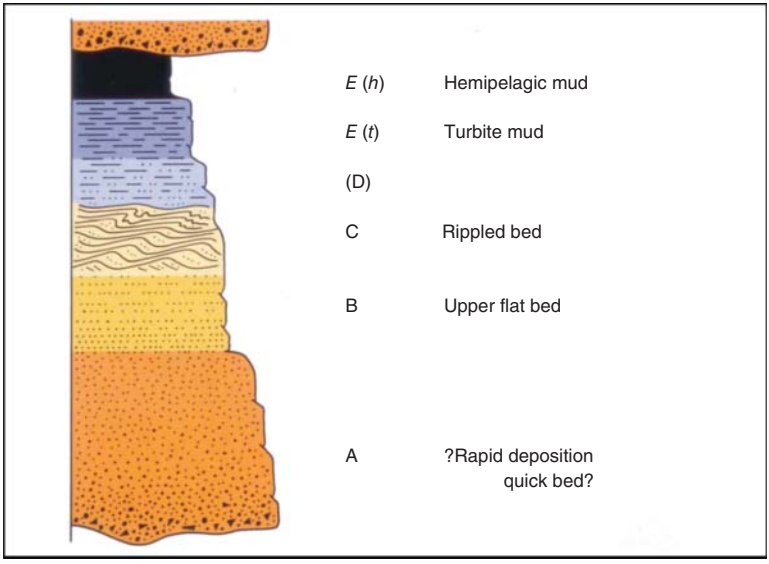


(c)

Figure 9.7 (*Continued*)



(a)



(b)

Figure 9.8 (a) Schematic deepwater depositional model showing the variety of different potential environments from the shoreline/slope to the abyssal plain; (b) classical example of the Bouma depositional model for turbidite facies. The vertical profile controls reservoir quality, but it is seldom that all elements of the cycle are preserved.

been in production since the 1950s and at the time of the study was being considered for gas storage. The age of the field meant that data were limited although there were more than 30 appraisal and development wells with logs and around 350 m of core from one central well. With these data, a robust layer-cake stratigraphic correlation was constructed and a simple facies model was developed. The key to modelling the sequence was in the shifting pattern of packages defined by the isochore thickness maps. The conceptual model was of elongated turbidite lobes deposited on a gentle ramp or slope that was subsiding rapidly due to tectonic activity. The sand was line sourced from the nearby shelf, rather than a single entry point, resulting in a little channelling and widespread sheet-like distribution. Eventually, subsidence stopped and a sequence of progradational shallow marine sands was deposited parallel to the shoreline.

9.5.1 Building the Model

The structural framework of the Hamitabat Field was defined from a limited set of 2D seismic lines but a detailed correlation scheme based on repeated stacking patterns of thick packages of blocky proximal sands and upward fining distal sands from NE-SW; packages vary between 1 and 25 m in thickness, with a mean value of 3 m. The result is two zones, A and B, the former being divided into three sub-zones. For each zone, an isochore map was constructed that showed the effect of auto-cyclicity on deposition: sands are deposited where the accommodation space is greatest and subsequently deposition shifts to the next low area. In this way, the depositional sequence is built until the shallow marine sands are the final deposits. The isochore maps are generated from the well correlations.

Five facies are recognized: clean sands, low-permeability sands, cemented sands, heterolithics and mudstones. The sands were modelled as elliptical objects with dimensions derived from analogue data typical of mixed turbidite systems: given a mean thickness of 3 m, the width of bodies was modelled as between 10 and 100 m and length 1000 and 10,000 m. There is also a vertical proportion curve for each based on the well data and also a probability distribution function (PDF) related to the proximal–distal relationship on body thickness. Each facies has a separate distribution of porosity and associated permeability, although there is some overlap.

In the model rebuild, I have used two zones of variable thickness to show how the focus of deposition changes; I have also built the upper

model with ellipse-shaped objects and used SIS with very elongated variogram ranges in the lower model (Figure 9.9).

The conclusions drawn at the end of this study were as follows:

- Evaluation of stacking patterns and the identification of cyclicity provide a useful correlation tool in turbidite sandstones.
- Correlatable surfaces can have significant impact on vertical permeability that needs to be incorporated into the modelling process.
- Isochore mapping allow insights into large-scale depositional controls that can be utilized in populating the facies model.

Submarine fans are often sand-rich and characterizing them becomes a matter of modelling different rock types, where sand is the dominant lithologies. Any non-reservoir lithologies can be modelled as minor objects constrained by well data in the overall volume. In Figure 9.9b, I have used channel objects with wide levees attached in a background of shale; the ratio of channel facies to shale is 3:1.

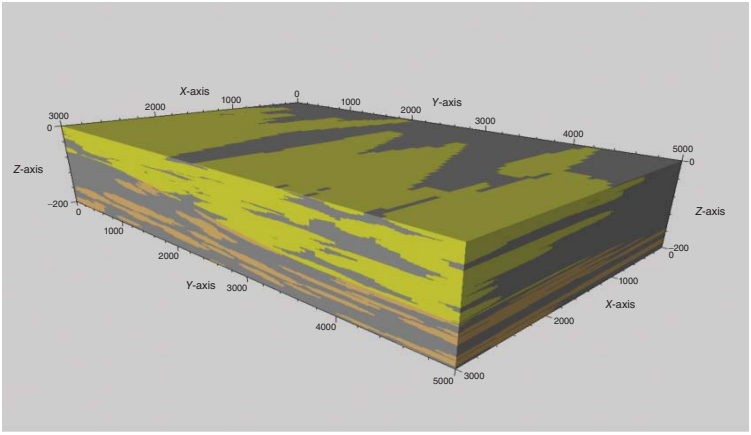
If there is high-resolution seismic data in stratigraphically younger sediments, discrete channel bodies can often be visualized and modelled directly once you know whether they are sand of shale filled. Often seen as seismically bright objects, these channels are commonly filled with gas, the density difference between gas- and liquid-filled pores providing the response.

9.6 Carbonate Reservoirs (Figure 9.10)

Most carbonate reservoirs are found either as shelves, ramps or reefs or a combination of both. The primary depositional controls on reservoir quality are often destroyed by diagenesis, resulting in a mosaic of rock types. For this reason, it is often sensible to model carbonate facies using indicator simulation algorithms (see Chapter 6 for a review of carbonate reservoir characterization). Other things to think of when modelling carbonates are pore geometries, fractures and massive dolomitization resulting in collapse of the rock fabric. When modelling carbonate facies, always ensure that you use colours from pink-blue palette, it is much more effective!

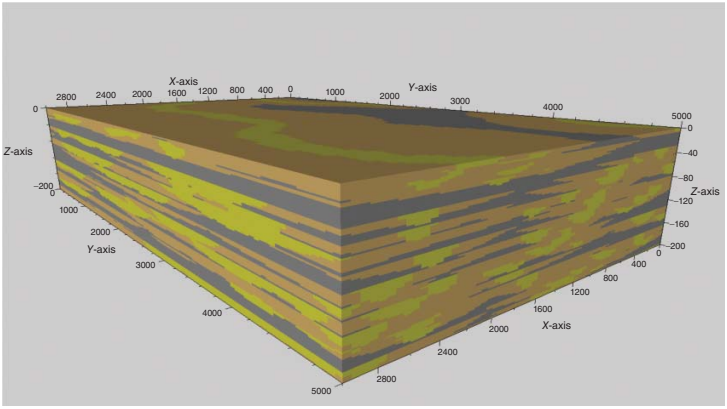
Tectonics and climate in addition to sea level changes are the three main factors controlling the sedimentation of carbonates. However, the first two factors together control the third one.

– Tectonics controls the lack or abundance of siliciclastic material, which is necessary for carbonate sedimentation. The input



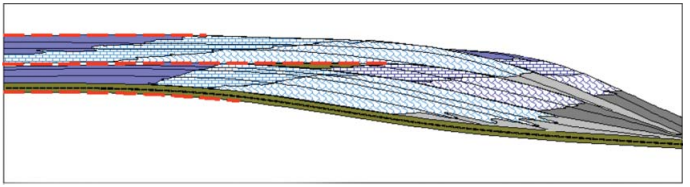
(a)

Figure 9.9 (a) A two-zone model representing deepwater deposition. In the upper zone, the yellow sands are distributed using elliptical objects between 1000 and 5000 m long and 100 and 1000 m wide up to a sand volume of 50%. In the lower zone, a similar volume of sand is distributed using an indicator simulation method in which the major variogram direction is 5–10 times greater than the minor orientation; (b) the lower image is of a sand-rich, channelized turbidite system where the attached levees are up to 10 times the width of the channels. The background shales potentially act as vertical barriers to flow.



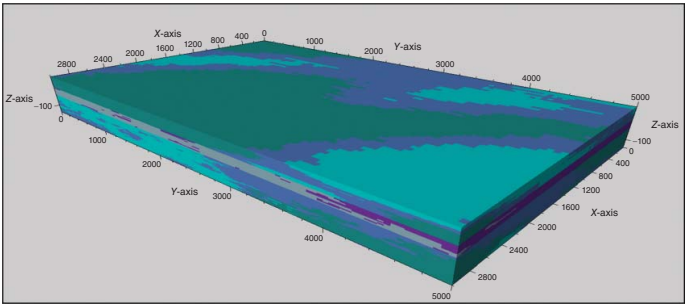
(b)

Figure 9.9 (*Continued*)



(a)

Figure 9.10 (a) A carbonate ramp conceptual model using sequence stratigraphy to build a series of prograding packages with episodic transgressions leading to non-carbonate sedimentation; (b) a model comprising three sequences of reservoir limestones (blue/green) and non-reservoir evaporites (purple/grey). The reservoir zones have been constructed using SIS and without trends to capture the different types of distribution, randomly mosaic (lower) and aggradational build-ups (upper). The three colours in the reservoir zones represent good-, moderate- and poor-quality rock types, each could subsequently be modelled with appropriate ranges of porosity.



(b)

Figure 9.10 (*Continued*)

of terrigenous sediments dilutes the carbonate components of sediments and seriously affects carbonate production, resulting in the formation of a distinct type of a depositional setting for carbonates such as shelf, ramp and platform.
- Climate is a major control over sea level changes and is considered one of the three main factors controlling carbonate sedimentation. The prevailing weather determines water circulation, temperature, salinity and nutrient supply. Higher organic production takes place in low latitudes around 30° of either sides of the equator. Although corals and most algae only exist in warm tropical water, molluscs and calcareous red algae may form substantial deposits even up to near poles (around 70° latitude). The highest organic productivity takes place in less than 15 m water depth, which is the best photic zone.
- Sea level changes are mostly related to climatic changes and/or tectonic activities. Although most of the thick carbonate sequences are deposited during highstand sea level, different types of cycles of up to a few thousands of years can be recognized within carbonate reservoirs.

Various sequences of facies observed within a carbonate reservoir are produced via changes caused by natural processes within the depositional environment and others caused by external factors such as sea level fluctuations. Depositional processes can lead to carbonate facies that vary both laterally and vertically giving rise to the extreme variations in heterogeneity in any one direction.

The depositional processes in each environment include the following:

Tidal flat progradation: Results in the formation of upward shallowing sequences via re-deposition of sub-tidal sediments over tidal flats and beach ridges during major storm periods.

Reef progradation: Seaward growth of a reef over the fore-reef slope at rimmed shelf margins; reefal sequences of various facies types will be produced, particularly vertically.

Carbonate sand migration: In high-energy locations, the migration of carbonate sand bodies is an important depositional process, particularly on ramps and sand shoals or shelf margins.

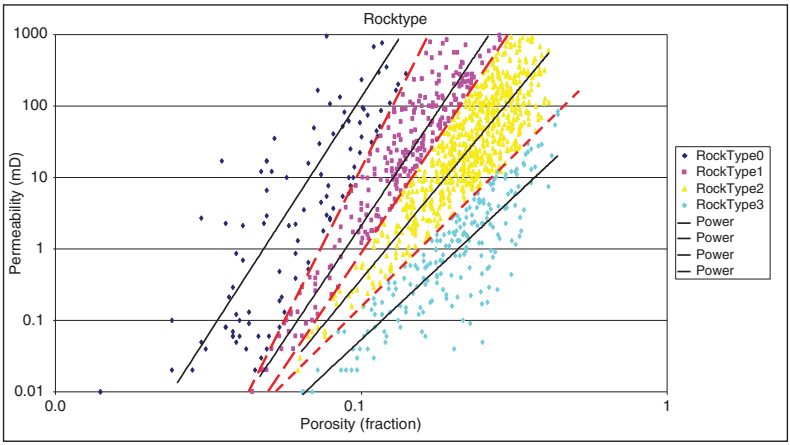
Offshore storm transport: Results in the deposition of carbonate shoreface sediments.

Slumps, slides, turbidity currents, debris flows: Various types of re-sedimentation of previously deposited sediments. They are very common and mostly restricted to shelf margins and slopes.

Extensive carbonate shelves have laterally continuous environments covering vast areas; however, the rock properties are highly variable. Fortunately, as in the Middle East, there are plenty of data points, wells, on which to build robust geostatistical relationships so long as you do not over complicate matters. One project we were given to work on had 87, very carefully characterized, rock types that we were required to reduce to a more manageable five reservoir rock types and three non-reservoir. Due to the highly layered system, we could represent non-reservoir layers very simply and focus on the heterogeneity observed in the more important oil-bearing zones (Figure 9.10b). It was the detailed description of the 87-candidate rock types that allowed us to build this complex facies and property model successfully.

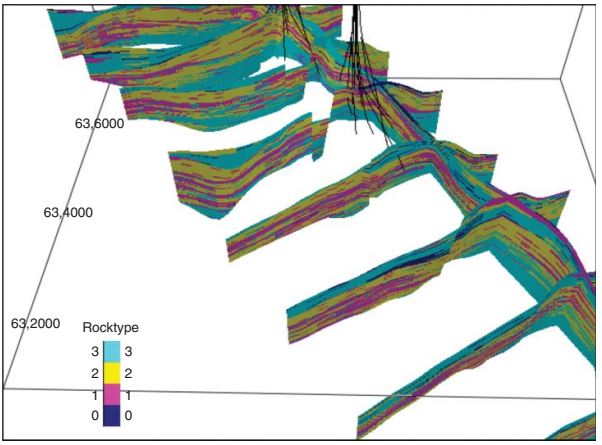
By their nature, carbonate ramps slope gently seawards so that facies change gradually, in a predictable way, with increasing water depth (Figure 9.10). This relationship is best captured using a Truncated Gaussian algorithm that allows the construction of facies belts. Detailed sedimentological studies aimed at describing the *in situ* biota are required to characterize the water depth and likely depositional energy. Once again, the impact of diagenesis is likely to mask primary depositional controls on reservoir quality, but local development of patch reefs may be recognized, and if warranted, modelled as separate bodies.

Large carbonate reef developments either at the shelf edge or as isolated pinnacles are often recognized first from seismic data. They may show all the classic elements of fore-reef, back-reef and reef core; these environments can again be modelled using TGSim but without necessarily trends, thus building concentric rings of lithologies. Where developed at a shelf edge, often structurally controlled, these deposits become the focus of thermobaric (high temperature and pressure) brines that corrode the rock fabric during dolomitization and the formation of cavernous vugs! Some fields along the margin of the Gulf of Suez have suffered this type of diagenesis, leaving reservoir engineers unable to history match production. Rock typing is an effective way to deal with carbonate reservoir, such as the Lucia approach to characterization (Figure 9.11a). Within a well-defined facies model, the rock types can be distributed using vertical distribution profiles defined from the well data (Figure 9.11b).



(a)

Figure 9.11 (a) An example of the Lucia rock-type classification for non-vuggy dolomites based on core porosity and permeability data; (b) rock types distributed according to a well-defined facies scheme of low-energy peri-tidal to open offshore environments.



(b)

Figure 9.11 (*Continued*)

9.7 Fractured Reservoirs (Figure 9.12)

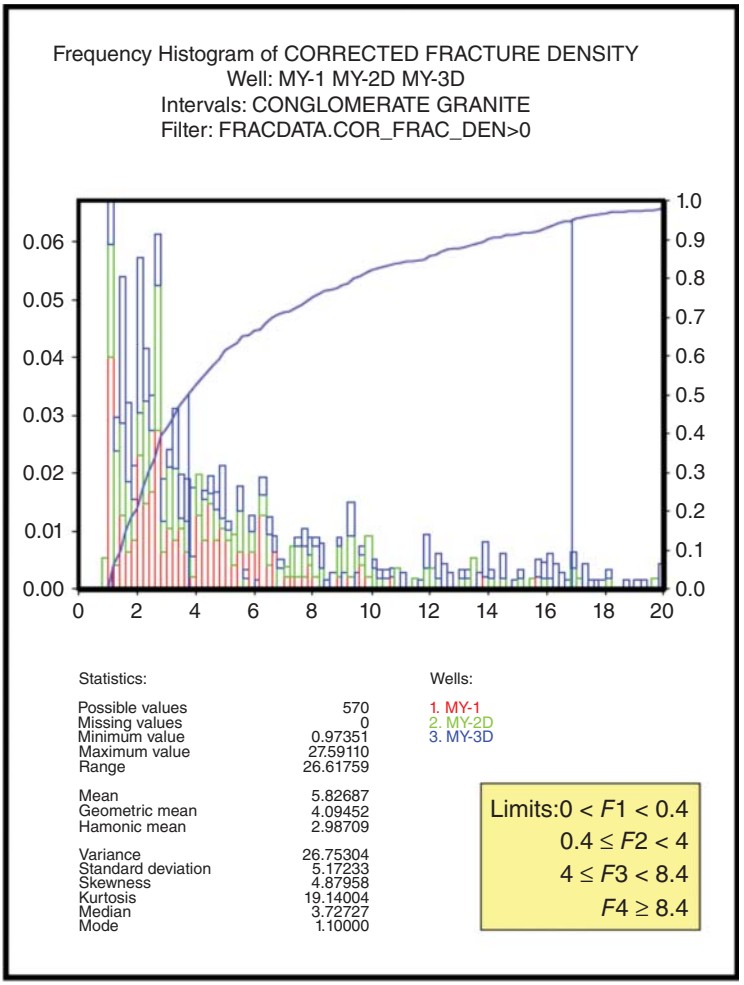
Fractures are common in carbonate reservoirs and often form the main storage and flow elements, as matrix porosity and permeability are often minimal: the following comments apply equally to clastic and basement reservoirs. Fractured reservoirs may be thought of as highly heterogeneous and unconventional, with a great many uncertainties. A wise old reservoir engineer once told me that old geologists needed a discrete fracture network (DFN), so they could demonstrate that they knew how the reservoir worked; engineers could do the same thing using permeability multipliers, and there is a lot of truth in that adage.

Most fractured reservoirs have high initial flow rates, but experience rapid depletion locally, with some wells ceasing to flow soon after start-up; this is known as *flush production*. Reservoir columns are often extensive, several hundreds of metres and oil–water columns are hard to define; vertical segregation of fluids due to gravity is also common. These problems often result in economic failure because the geology is poorly understood or the petroleum engineering solutions are inappropriate. Failure to intersect open fractures or sweet spots and the inability to complete wells in the most fractured intervals are common during development, resulting in poor connectivity and rapid depletion of local zones. Early water breakthrough can also be a common problem when the extent of the fracture network is not understood resulting in poor sweep efficiency.

There are many ways to classify fractured reservoirs, but the following is most useful to the reservoir modeller (McNaughton and Garb, 1975; Nelson, 1992).

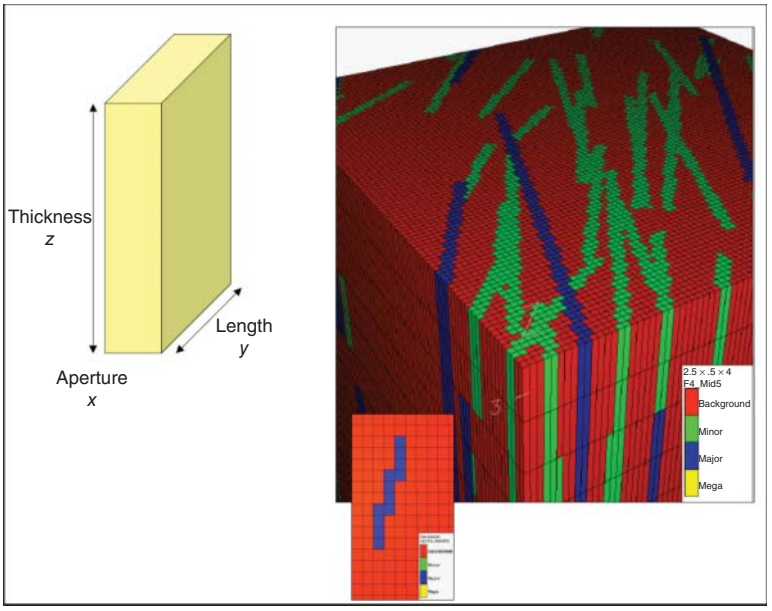
- *Type A*: Conventional relationship between porosity and permeability; fractures may act as baffles to flow if cemented.
- *Type B*: Reasonable matrix porosity but fractures assist or enable flow in the reservoir.
- *Type C*: Unconventional; fracture porosity and permeability dominate storage and productivity.

Like most reservoir studies, good results come from sound data gathering, understanding the underlying geology and integration of overlapping data sets. One fundamental aspect of understanding a fractured reservoir is to understanding the present-day stress regimes and record of strain undergone by the rock, the permanent response of the rock to stress. The former may influence the orientation of the



(a)

Figure 9.12 (a) Fracture density as seen in core and image data from three wells in a granite basement field. These are used to characterize fracture types for subsequent modelling; (b) the required geometry of each fracture type and how they may be modelled as vertical objects within a small prototype model.



(b)

Figure 9.12 (*Continued*)

model grid and the later the stratigraphic layering. Three mutually orthogonal axes represent stress in the reservoir, where $\sigma_1 > \sigma_2 > \sigma_3$: no shearing can take place along the principal stress direction. A similar nomenclature exists to describe strain: $\varepsilon_1 > \varepsilon_2 > \varepsilon_3$. The type of geological structures formed during tectonism depends on the relationship between the stress axes: normal faulting requires the vertical axes to be the principal stress, whereas a reverse fault requires a horizontal stress direction to be greatest.

To model fractures requires a number of attributes to be described, foremost of these being the orientation, width or aperture, length and spacing. Much of this information can be collected from image log data and core, but length can only be estimated from outcrop data or *in situ* well production data. Logs can also give some information on whether fracture is open and therefore flowing or closed and thus baffles to flow. There are some rules of thumb that can be applied to estimate fracture length: the thicker a fractured unit is and the closer the spacing, the longer the fracture length (Aarseth *et al*., 1997). Fractures often occur

in corridors and seismic attribute data such as variance can be used to identify these potential sweet spots.

What drives the formation of fractures? Simply put the structural history, the stratigraphy and the litho-mechanical properties of the host rock; whether the fractures are strata-bound or not has an impact on the vertical connectivity. The influence of folding can also be a major contributor to the formation of fractures, creating extensional patterns and shearing (Cooke-Yarborough, 1994). Curvature analysis is a simple way of visualizing the potential for fault or fracture formation using the tools available in most software packages. Curvature is the change in the tangent vector of a surface with distance: joints or fractures form parallel to minimum curvature directions and open parallel to the maximum curvature direction.

Many reservoir engineers recognize the importance of geomechanics in reservoir simulation and there are a number of modelling tools available to try and capture the impact of *in situ* stress on flow in the reservoir: this a topic way beyond this book and its author!

A 'simple' approach to modelling fractures in a basement field was documented for the Yufutsu Field, Hokkaido, Japan (Anraku *et al*., 2000). The field is a fractured granite, gas condensate with no primary matrix porosity. The fractures are categorized into four types: Mega, Major, Minor and halo fractures. The Mega fractures govern flow, whereas Micro fractures provide storage. Gas migration occurred after fracture formation. The reason to build static and dynamic models of the field was to try and understand the abnormal production behaviour.

A three-stage model building study was initiated in which small-scale prototype models were built of stochastically distributed fracture objects, followed by a 200,000 cell single porosity simulation model in which effective permeability was calculated, and finally a dual porosity model was built and upscaled to single well and full field models. This model was used for both well planning and production forecasting.

Fracture types were defined from image logs; halo fractures were not included in the modelling because these are known to be sealed by silica cements. There was no way to estimate fracture length from well data or analogue data, so the focus was put on fracture density and orientation. Histograms of fracture density show a high frequency of low fracture density and conversely, a low frequency of high fracture density: this relationship was used to define and stochastically model families of fractures. The predominant fracture orientation is in

NE–SW, with most Major and Minor fractures dipping towards the NE or SW, whereas the Mega fractures dip primarily to the NE. A degree of well bias is recognized because the orientation of the boreholes and fractures whose dip and azimuth approximate to the borehole itself are under-represented. This was corrected during modelling.

The mean thickness, length and width of fractures were estimated from histograms plotted from the image log data and used to define the size of stochastic objects used in the model. The physical aperture values were set to two cell widths (equivalent to 5 cm) to ensure full corner-to-corner connectivity so that fracture communication is from fracture-to-fracture not just fracture-to-matrix.

Four fracture families were identified based on the fracture density histogram, F1–F4, each with similar fracture attributes (Figure 9.12). Effectively, a fracture facies log was generated for each well at one-metre intervals and upscaled over 5 m intervals. Four $10 \times 10 \times 10$ m box models were constructed ($400 \times 400 \times 50$ cells) and populated with one the fracture families (Figure 9.12b). The number of fracture bodies inserted is dependent on the density of the particular fracture type (Mega-Minor) and the ratio between the cylindrical fracture volume and the box volume. The presence of a particular fracture family in a well conditions the overall distribution of the objects, although a hierarchy of cross-cutting fractures is also modelled whereby Mega fractures can intersect all other fractures and Major fracture intersect Minor. The resulting fracture to matrix ratio for each family is used to approximate an average porosity for each box model. In this way, by combining the four box models, a realistic representation of the fractured field is built and then simulated.

9.8 Uncertainty Modelling

The greatest subsurface uncertainties in volume estimation are the top structure map (a function of depth conversion), the position of the hydrocarbon water contact and net-to-gross ratio; porosity and water saturation uncertainty should only be a matter of a few percentage points. Most of the software tools available have workflow managers that may be used for running many realization of a model to give a range of equiprobable results. Automated uncertainty tools are heralded as the future of integrated reservoir modelling, but only if they increase the degree of interaction between the subsurface disciplines.

While framing the project, it is essential that the team considers the subsurface uncertainties from depth conversion to reservoir connectivity and to estimate the range of variability in a given property. This may be done by building a deterministic Low-Mid-High matrix for each uncertainty or by constructing multiple stochastic models or multiple deterministic scenarios where one or more input parameter is tested. In most companies, it is easier to explain or 'sell' a deterministic approach than some complex workflow that tries to address all the uncertainties at once. We will look at the approaches that have been applied in three different circumstances: structural, net-to-gross and petrophysical.

9.8.1 Structural Model Uncertainty

Firstly, there is the scenario option: a discovery well with a single depth conversion routine finds the top reservoir 15 m shallower than predicted, so a revision of the time–depth relationship is required. The development geophysicist now has more local data than before with checkshots and wireline logs which can be used to calibrate the overburden more accurately. He also has a number of ways in which the T–D relationship for the field area can be built; which should he use? And should you tie the revised top reservoir surface to the well or test each depth conversion method and see the apparent mismatch between well and surface? In this way, the team may generate 5 or more rock volumes for comparison. The choice then lies with the team and asset manager and whether to build all the models or 2–3 representative cases, depending on the overall object of the project; a volumetric range or the next appraisal well location (Figure 9.13).

Secondly, there would be the stochastic approach to a single top reservoir map. When a field has been fully appraised, data will be available on several wells; there may be a new 3D seismic survey or reprocessed data volume to utilize in the depth conversion. In this case, a single depth conversion routine may be run and the difference between the well picks and the resulting surface will give a range of uncertainty across the field. This range may then be used to produce realizations of the inter-well volumes that represent a PDF. Past experience has shown that ~30 realizations will capture around 90% of the volume uncertainty. This latter approach can be built into the workflow as a simple loop and run as many times as required.

A new workflow approach to structural uncertainty is termed *Model Driven Interpretation* (Leahy and Skorstad, 2013). As part of the new

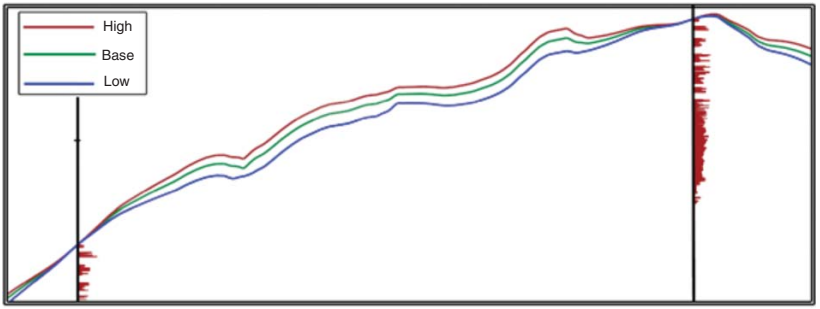


Figure 9.13 A simple approach to structural modelling based on depth conversion uncertainty resulting in 3 deterministic models of top reservoir. *Source*: Reproduced with permission of Emerson-Roxar.

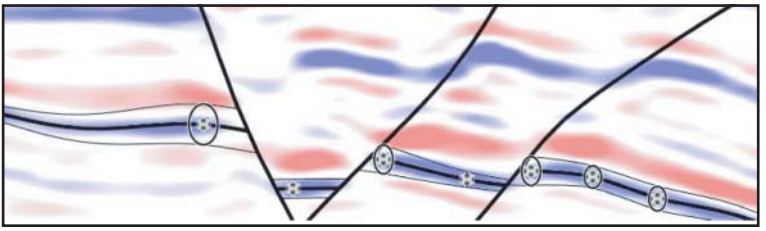
workflow, once the seismic surfaces and faults have been imported or interpreted in the model, the interpreter is able to define structural uncertainties based on the seismic interpretation results and create standard deviation surfaces and fault envelopes. Then one can create a reference structural model and full field structural model based on the interpreter's requirements. Rather than focusing on a single horizon or fault, in the new workflow, uncertainties are represented by envelopes that change size based on the interpreter's estimate of uncertainty on each interpreted location.

The interpretation method measures both a best-estimate interpretation of a geological feature and an associated uncertainty (Figure 9.14a); this shows that as the interpreter moves away from the well control, where there are minimum uncertainties, the uncertainty increases. As compared with the conventional workflow, where uncertainty can only be moved vertically by the constant factor, in the new workflow for each point, uncertainty is guided by the data (Figure 9.14b). Following the model-driven interpretation process, a standard deviation map is then extracted, which is also used to capture the uncertainty before the building of a structural model and is then taken through the remaining elements of the workflow to create multiple realizations.

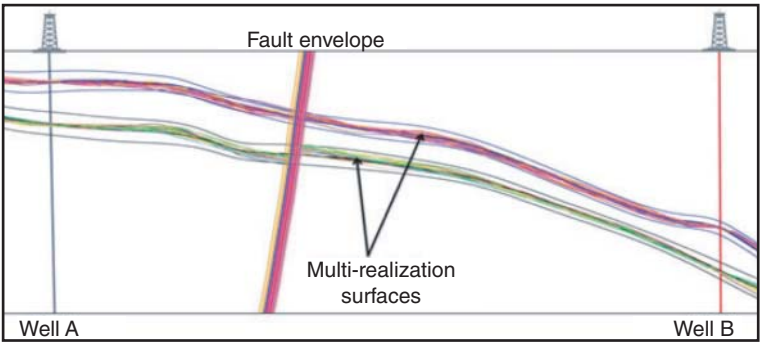
The use of uncertainty envelopes for horizon and fault data allows the modeller to generate standard deviation maps and multiple realizations of the surfaces. From these, a range of gross rock volumes is generated within a 3D grid from which P90, P50 and P10 values can be extracted (Figure 9.14c) as well as indicating which horizons, velocity models or fluid contacts are affecting the results.

9.8.2 Facies Model Uncertainty

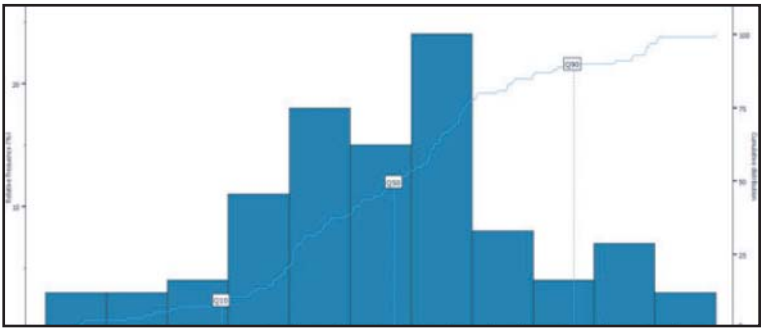
With a facies model in place, the uncertainty is usually about the proportion of net reservoir; this may be because of limited well data or lack of knowledge regarding sand body orientation. Take for example a laterally extensive field with only a limited number of appraisal wells all drilled along the crest of the structure. High-quality coarse-grained sandstones provide the reservoirs, separated by non-reservoir shale; the conceptual model is of a sequence of stacked, high-energy, braided channel systems, but because the wells are all aligned, we have no idea of the orientation of the channels and seismic does not help. Neither do we know the lateral extent of the individual channels nor the channel



(a)



(b)



(c)

Figure 9.14 Results of a model driven workflow approach (Leahy and Skorstad, 2013); (a) shows the areas of seismic uncertainty when picking surfaces due to poor resolution; (b) shows the multi-realization surfaces having run the stochastic routines for both surface and fault uncertainty; (c) is a histogram of the range in volumetric results based on the workflow. *Source*: Leahy and Skorstad (2013). Copyright 2013, EAGE publications.

fairway: we need to treat this as two separate issues to begin with and hope that another appraisal well is drilled soon!

Dealing with channel orientation first, we can take an optimistic view that the channels are oriented along the crest of the structure or a pessimistic view that they are orthogonal to the crest; we might chose a middle road and have them oriented at an angle to crest (Figure 9.15). The impact of orientation is likely to be one of volume, as wells penetrating the channels may either show communication (optimistic) or isolation (pessimistic). By modelling these as cases as different scenarios, we can test the volumetric outcomes further by varying the channel width stochastically to create the second variable and so distribute the associated net-rock volume. Dealing as we are with channels, we are able to choose the type of distribution to use for each parameter: normal, triangular, uniform or fixed (Figure 9.16).

In the end, a horizontal well was drilled along the crest and found sand for 1 km, indicating a probable orientation to the NE; a orthogonal side-track was drilled that proved more sand up to a kilometre

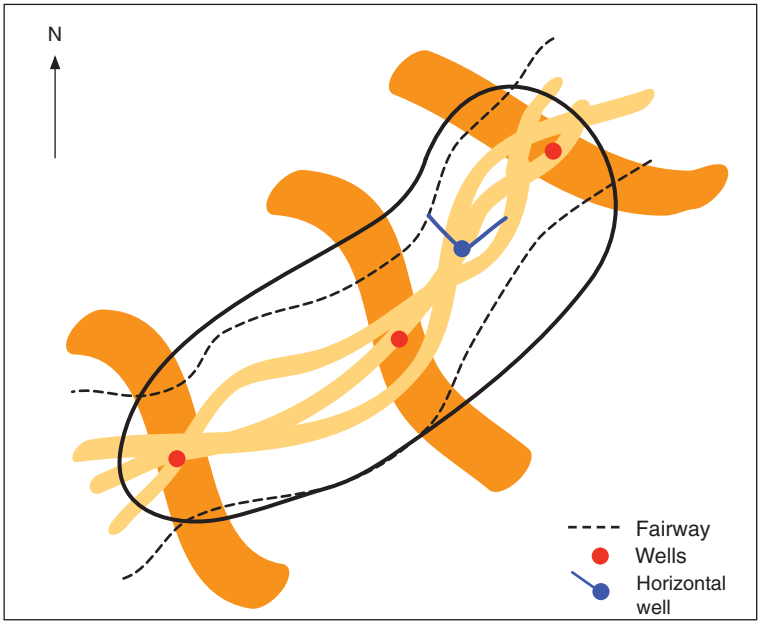


Figure 9.15 Uncertainty in channel geometry and orientation makes a significant difference in volumetric estimation and reservoir connectivity.

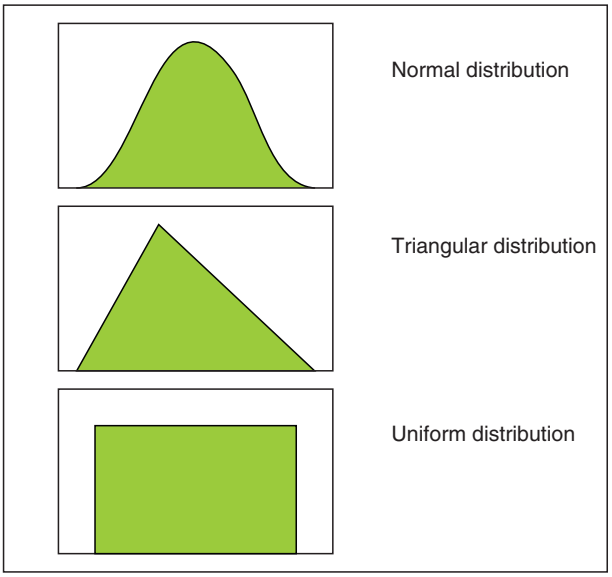


Figure 9.16 Examples of different distributions used in facies modelling to introduce a stochastic element into object geometry and orientation.

away from the well, suggesting that at least in one reservoir zone we are dealing with a laterally extensive sheet-like channel fairway that maximized net reservoir volume at least in the northern part of the field. More representative models that captured all this information could then be built.

In a field with stacked sand bodies, not all wells will penetrate all the reservoirs; therefore, the software may not include sand at those deeper levels reducing the overall sand content in the model. It may be necessary to deterministically model a scenario where sand is present by artificially deepening a well and increasing the sand body count. This is a case of known unknowns or model-driven modelling.

9.8.3 Petrophysical Uncertainty

I once asked a petrophysicist: What was the uncertainty in his water saturation model? the reply was '±15%' and my response was that the saturation height relationship I planned on using had plenty of leeway, only to be told I had to match the well saturations exactly: no easy task given the uncertainty. This was a carbonate reservoir, so I was able to

convince the reservoir engineer that saturation height would give a more robust answer, especially as the petrophysicist's water saturation model used only single values for *a*, *m* and *n* in the Archie equation, when we know that *m* especially varies with rock type. It helps a modeller to understand how the data you are modelling was derived.

How does porosity vary in a cell of 50 m × 50 m × 1 m? We could look at a homogeneous vertical sequence of 50 m thick and say 'very little', but that would not hold in a heterogeneous sequence. If there is sufficient spatial information in all the three directions, we might be able to build a variogram model to distribute the property, but without that robust database, the modeller can only use experience and regional or analogue knowledge. I firmly believe that by building a representative facies model, the uncertainty in petrophysical data can be managed in the final property model.

An uncertainty study that was carried out some years ago on a shallow marine sequence (*pers comm* Ahmed Shariff) involved a workflow that varied depositional and petrophysical properties and then ranked the results using streamline simulation (Figure 9.17). The depositional properties that were varied included progradation angle of facies belts, the correlation width of the belts and the orientation and width of potential thief bodies. The petrophysical properties to vary were the mean horizontal permeability of the thief bodies and the correlation length. The petrophysical properties were fixed while the depositional uncertainties were modelled and then the petrophysical properties were varied. In all, there were 104 realizations and a base case model (Table 9.2).

The results of the streamline simulation were plotted in terms of drained volume against time of flight for each of the 104 realizations and the base case to give statistically valid range of drained volumes and the uncertainty in terms of a cumulative probability plot (Figure 9.18).

9.9 Summary

The train of thought that goes behind each of these examples is what is the property or properties, variable or variables, scenario or scenarios that has the greatest impact on modelling flow in the reservoir and at what scale does it apply. In the carbonate example, it is likely that the pore-scale variability is the one that needs to be understood, and in the shallow marine example, the hierarchy of facies that

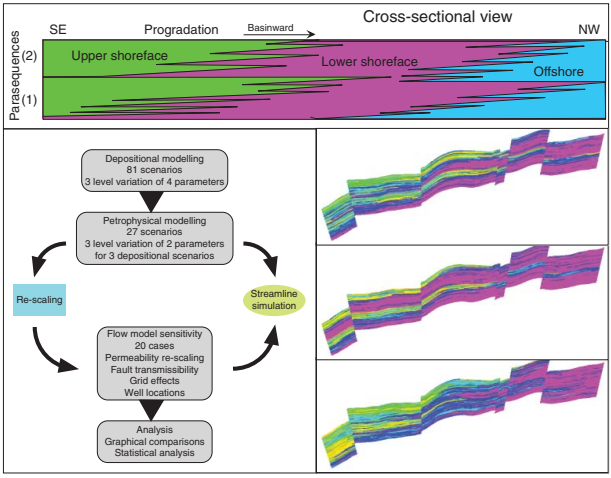


Figure 9.17 Conceptual model, uncertainty workflow and permeability distributions for three shallow marine depositional scenarios. *Source*: Reproduced with permission of Emerson-Roxar.

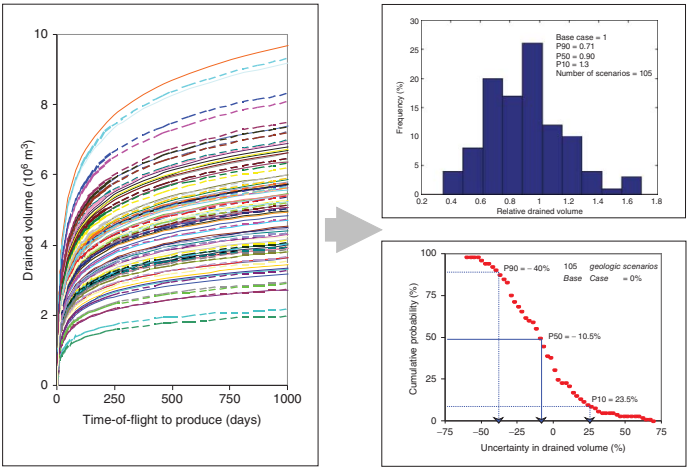


Figure 9.18 Time-of-flight results displayed as a function of the drained volume for each of the realizations as well as frequency and cumulative probability plots. *Source*: Reproduced with permission of Emerson-Roxar.

Table 9.2 Input variables for uncertainty modelling of a shallow marine deposition system.

Variables	Low (%)	Medium	High (%)
Progradation angle (θ)	−50	3	+50
Facies belt correlation width (m)	−25	2000	+25
Thief zone orientation (θ)	−10	150	+10
Thief zone width (m)	−30	350	+30
Thief zone permeability (mD)	−15	7	+15
Horizontal permeability correlation length (m)	−50	200	+50

needs to be captured. Draw the model you are trying to build before you press a single button of the software; the software is a toolbox, so select the right tools for the job and assess the results when you have finished.

Afterword

How do you finish a book like this, when there are so many aspects to consider? In 2015, a two-day conference was held in Aberdeen called 'Recognising the Limits of Reservoir Modelling – and how to overcome them'; the conference was held under the auspices of the Petroleum Group of the Geological Society. There were four sessions with 18 papers and 4 keynote talks given by many of the leading exponents for academic and practical reservoir modelling, and one or two sceptics! Interestingly, none of the major software vendors presented papers, usually a sign that there is little new in the functionality or application of their software. I thought that to summarise this current understanding of the state-of-play in reservoir modelling might shine a light on the future direction of the activity. Upon reading the abstract volume, it is apparent that the same challenges are inherent in the process; what was a challenge 20 years ago is still a challenge today and many of the solutions are also the same.

The four sessions were based around multi-scale modelling, workflows, geostatistics and dynamic performance; I could have structured this book into the same four sections. There were a few new buzzwords I didn't recognize that had to be researched, such as sketch based interface modelling (SBIM) and rapid reservoir modelling (RRM), decision driven modelling (DDM) and 'Big Loop' workflows, although this was a term familiar to me 10 years ago!

SBIM blends concepts from computer graphics, human–computer interaction, artificial intelligence and machine learning. Recent improvements in hardware, coupled with new machine learning techniques for more accurate recognition, and more robust depth inferencing techniques for sketch-based modelling, have resulted in an explosion of both sketch-based interfaces and pen-based computing devices.

Reservoir Modelling: A Practical Guide, First Edition. Steve Cannon.

RRM is a research project that tries to overcome the challenge of constructing or refining complex reservoir models at the appraisal, development or production stage (Figure AW.1). The lack of an intuitive set of modelling, simulation and visualization tools that support expert interpretation from geophysicists, geologists and reservoir engineers significantly increases the challenge. A particular limitation is the lack of software that allows conceptual models to be rapidly created, using a simple, intuitive interface and then interrogated for key reservoir properties and behaviours.

DDM was discussed in a paper from 1996 (Gawith and Gutteridge); the strapline was 'the next big thing'! The paper was presented at that year's SPE Reservoir Simulation Symposium and was a follow-up of the 'earth model' approach adopted by that particular operator at the time, along with TDRM (top down reservoir modelling); another process that was tried by different companies to rationalize the integrated nature of the reservoir modelling workflow.

'Big Loop' is an integrated approach to ensuring consistency between geological and reservoir simulation models (Webb *et al.*, 2008). Then, the workflow relied on specific software products to complete the process of automated history matching; today, the core of the integration is a workflow manager that controls all modelling steps from depth conversion to simulation in batch mode, in addition to running sensitivity screening and assisted history matching (Figure AW.2). The sensitivity screening is achieved through a workflow manager that allows changes in parameters (e.g. OWC and facies fraction) and scenarios (e.g. velocity models, different facies modelling approach or conditioning), in order to re-run the entire workflow (Saka *et al.*, 2015).

One consultancy group presented their view of the workflow, comparing it to the Forth railway bridge: the nodes for discussion and decisions (Figure AW.3) and the cantilevers, when the work was actually done (Chellingsworth *et al.*, 2015). By tuning the various elements within the bounds of the (reliable) data and (appropriate) concepts, mutually acceptable 'fixes' can be implemented in the geological model, the simulation model or both. This is still a linear approach, but at least, the team works together rather than in isolated 'silos'. When the team is truly integrated, they are able to apply 'a fast iteration process' (is that FIP?).

Of particular interest was a paper looking at surface-based representation of geological heterogeneity and unstructured space and time adaptive meshes (Jackson *et al.*, 2015). In this approach, geological

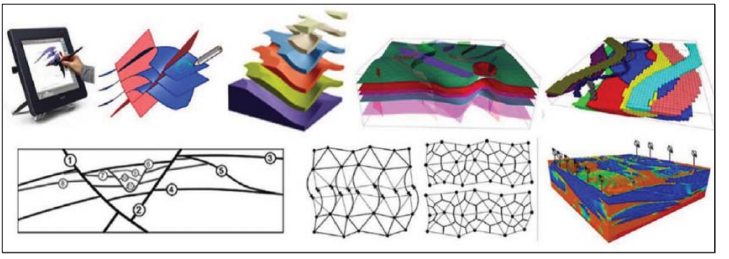


Figure AW.1 Rapid reservoir modelling is a research project run by a consortium of universities and sponsors to develop software for prototyping complex reservoir models by means of novel interactive modelling tools, exploratory visualization and numerical analysis. The idea is not to replace existing workflows but to supplement them by allowing rapid testing of geological concepts and their impact on reservoir behaviour. *Source*: Reproduced with permission of the RRM Consortium.

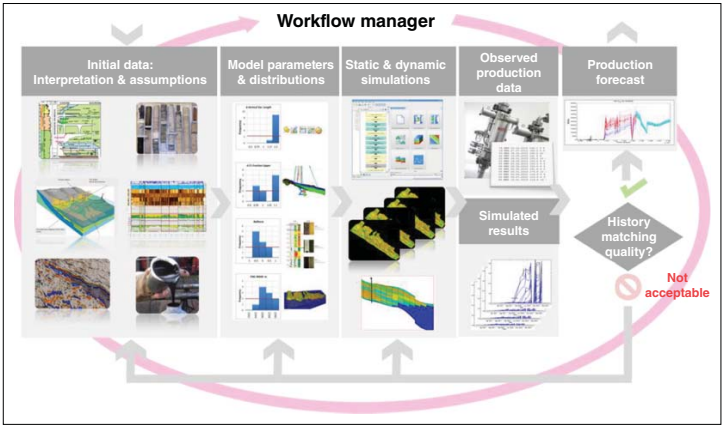


Figure AW.2 The 'Big Loop' workflow combining static and dynamic observations and results to quantify uncertainty and improve history matching. The workflow enables the rapid incorporation of new data, as well as analysis of alternative geological scenarios and property parameters, in order to screen multiple realizations and filter out the best production data-matched among them. *Source*: Saka *et al*. (2015). Copyright 2015, Geological Society of London.

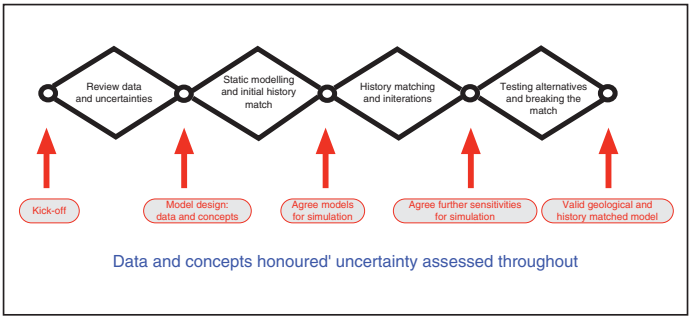


Figure AW.3 The concept of nodes and cantilevers based on the Forth Railway Bridge and used as a modelling workflow method. *Source*: Chellingsworth *et al*. (2015). Copyright 2015, Geological Society of London.

heterogeneities are represented as discrete volumes bounded by surfaces, regardless of whether the heterogeneities are structural, stratigraphic, sedimentological or diagenetic in origin. Within these discrete volumes (termed *geological domains*), the petrophysical properties are constant. The surface-based modelling methodology is, in principle, simple: numerous surfaces are used to represent (i) fault surfaces, (ii) stratigraphic surfaces, (iii) boundaries between facies associations and/or facies types within facies associations, and/or rock types or lithologies within facies types, (iv) boundaries between different regions of diagenetic modification of rock properties and (v) fracture surfaces. The surfaces are ranked into a hierarchy based on relationships that specify which surfaces truncate, are truncated by, or conform to, other surfaces and are generated using deterministic or stochastic techniques; these techniques are analogous to those used in conventional geological modelling; except here, the model is built without reference to an underlying grid. The resulting surface-based geological model is discretized for flow simulation using an unstructured, tetrahedral mesh that honours the architecture of the surfaces and allows heterogeneity over multiple length scales to be explicitly captured using fewer cells than conventional grids (Figure AW.4).

One particular paper looked at the opportunities for reservoir modelling in terms of the systems (*workflows*), technologies (*software*) and people (*teams*) (Agar *et al*., 2015). The first opportunity is to ask more from the model: rather than modelling for comfort (ticking the box), use the process to learn more about the field and the uncertainties. Sketching the conceptual model is recommended as a key step in model design; a quick way to discuss the knowns and unknowns. Another opportunity lies in populating the reservoir system not the reservoir discipline; we do not know all the answers, so a holistic approach should be adopted by looking at all the data and the results to determine what is controlling flow in the reservoir. Other opportunities exist in new software tools from the smaller vendors or academic departments (SBIM) that find it difficult to get airtime with oil companies because the tools may not be commercial or are too radical for some. This industry is very conservative when it comes to new tools, solutions or suppliers, like the prospective client that told me that even though his current supplier results were inaccurate, he knew how inaccurate: he had no idea how inaccurate my solution might be!

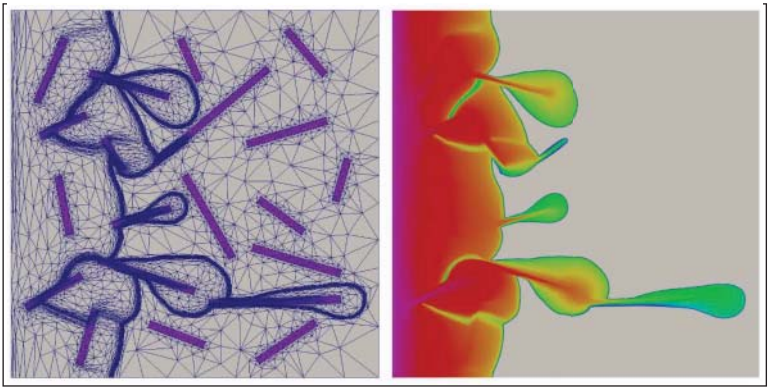


Figure AW.4 A 2D slice through an example 3D immiscible two-phase flow simulation using an unstructured mesh. Snapshot in time showing (a) dynamic adaptive mesh refinement (AMR) to capture (i) high-permeability features ('fractures' shown in purple) embedded in a low-permeability background and (ii) the location of the waterfront; (b) water saturation (high values in red), with injection over the left-hand face. As the waterfront advances through the model, AMR allows its complex geometry to be accurately captured. *Source*: Jackson *et al*. (2015). Copyright 2015, Geological Society of London.

The last opportunity is the one that I am most interested in and that is the opportunity to train a new generation of reservoir analysts, specifically to break down the barriers between the disciplines, and I hope that this book might go some way towards that aim.

References

Aarseth, E.S., Bourgine, B. and Castano, C. (eds) (1997) *Interim Guide to Fracture Interpretation and Flow Modelling in Fractured Reservoirs*, European Commission, EUR 17116 EN, pp. 161–188.

Agar, S.M., Sousa, M.C., Geiger, S. and Hampson, G. (2015) Systems, technologies, people, in *Recognising the Limits of Reservoir Modelling – and How to Overcome Them (Abstracts Volume)*, Petroleum Group, Geological Society of London.

Amaefule, J.O., Altunbay, M., Tiab, D., Kersey, D.G. and Keelan, D.K. (1993) *Enhanced Reservoir Description: Using Core and Log Data to Identify Hydraulic (Flow) Units and Predict Permeability in Uncored Intervals/Wells*. SPE 68th ATCE, Houston, SPE26435.

Anraku, T., Namikawa, T., Herring, T., Jenkins, I., Price, N. and Trythall, R. (2000) Stochastic fracture modelling of the Yufutsu Field. Society of Petroleum Engineers SPE 59400 presented at: *Asia-Pacific Conference on Integrated Modelling for Asset Management, Yokohama, Japan*.

Asquith, G.B. (1985) *Handbook of Log Evaluation Techniques for Carbonate Reservoirs. Methods in Exploration No.5*, AAPG, Tulsa, OK.

Bacon, M., Simm, R. and Redshaw, T. (2003) *3-D Seismic Interpretation*, Cambridge University Press, Cambridge, England.

Bear, J. (1972) *Dynamics of Fluids in Porous Media*, American Elsevier, New York.

Box, G.E.P. (1979) Robustness in the Strategy of Scientific Model Building. Technical Summary Report ≠1954, University of Wisconsin-Madison.

Budding, M. and Inglin, H. (1981) A reservoir geological model of the Brent Sands in Southern Cormorant, in *Petroleum Geology of the Continental Shelf or North-West Europe* (eds L.V. Illing and G.D. Hobson), pp. 326–334, Heyden, London.

Reservoir Modelling: A Practical Guide, First Edition. Steve Cannon.

Cannon, S.J.C. (1994) Integrated facies description. *DiaLog*, **2** (3), 4–5 (reprinted in*: Advances in Petrophysics – 5 Years of DiaLog* 1993–1997, 7–9 London Petrophysical Society, 1999).

Cannon, S.J.C. (2016) *Petrophysics: A Practical Guide*, John Wiley & Sons Ltd., Chichester.

Cannon, S.J.C. and Gowland, S. (1996) Facies controls of reservoir quality in the late Jurassic Fulamr Formation, Quadrant 21, UKCS, in *Geology of the Humber Group: Central Graben and Moray Firth, UKCS*, vol. **114** (eds A. Hurst *et al.*), Geological Society Special Publication, London, England, pp. 215–233.

Cannon, S.J.C., Giles, M.R., Whitaker, M.F. *et al.* (1992) A regional reassessment of the Brent Group, UK sector, North Sea, in *Geology of the Brent Group*, vol. **61** (eds A.C. Morton *et al.*), Geological Society of London Special Publication, London, England, pp. 81–107.

Chellingsworth, E., Kane, P. and Tian, X. (2015) Fast iteration-geoscientists and engineers working in harmony, in *Recognising the Limits of Reservoir Modelling- and How to Overcome Them (Abstracts Volume)*, Petroleum Group, Geological Society of London.

Conybeare, D.M., Cannon, S.J.C., Karaoguz, O. and Uyger, E. (2004) Reservoir modelling of the Hamitibat Field, Thrace Basin, Turkey: an example of a sand-rich turbidite system, in *Confined Turbidite Systems*, vol. **222** (eds S. Lomas and P. Joseph), Geological Society of London Special Publication, London, England, pp. 307–320.

Cooke-Yarborough, P. (1994) Analysis of fractures yields improved gas production from Zechstein carbonates, Hewett Field, UKCS. EAGE. *First Break*, **12**, 243–252.

Corbett, P.W.M. and Potter, D.K. (2004) *Petrotyping: A Basemap and Atlas for Navigating Through Permeability and Porosity Data for Reservoir Comparison and Permeability Prediction*. International Symposium Society of Core Analysts, Abu Dhabi, SCA2004-30.

Crabaugh, M. and Kocurek, G. (1993) Entrada Sandstone: an example of a wet aeolian system, in *The Dynamics and Environmental Context of Aeolian Sedimentary Systems* (ed. K. Pye), Geological Society Special Publication 72, pp. 103–126.

Cuddy, S.G., Allinson, G. and Steele, R. (1993) *A Simple Convincing Model for Calculating Water Saturations in Southern North Sea Gas Fields, Transactions, SPWLA*. 38th Well Annual Logging Symposium, Houston, S1-14.

Daly, C. and Caers, J. (2010) Multi-point geostatistics-an introductory overview. EAGE. *First Break*, **28**, 39–47.

Deegan, C.E. and Scull, B.J. (1977) A Proposed Standard Lithostratigraphic Nomenclature for the Central and Northern North Sea. Report of the Institute of Geological Sciences (now British Geological Survey).

Deutsch, C.V. (2002) *Geostatistical Reservoir Modelling*, Applied Geostatistics Series, Oxford University Press Inc, Oxford, England.

Deutsch, C.V. and Journel, A.G. (1992) *GSLIB: Geostatistical Software Library and User Guide*, Oxford University Press.

Doveton, J.H. (1994) *Geologic log Analysis Using Computer Methods*, American Association of Petroleum Geologists, Tulsa, OK. *AAPG Computer Applications in Geology No. 2.*

Doveton, J.H. and Cable, H.W. (1979) Fast matrix methods for the lithological interpretation of geophysical logs, in *Petrophysical and Mathematical Studies of Sediments* (ed. D.F. Merriman), Pergamon Press, Oxford.

Fertl, W.H. and Vercellino, W.C. (1978) Predict water cut from logs, in Practical Log analysis Part 4. *Oil & Gas Journal*, 15 May 1978–19 September 1978.

Folk, R.L. (1980) *Petrology of Sedimentary Rocks*, Hemphill Publishing, Cedar Hill, TX.

Gawith, D.E. and Gutteridge, P. (1996) Seismic validation of reservoir simulation using a shared earth model. *Petroleum Geoscience*, **2**, 97–103.

Guillotte, J.G., Schrank, J. and Hunt, E. (1979) Smackover reservoirs interpretation case study of water saturation versus production. *Gulf Coast Association of Geological Societies Transactions*, **29**, 121–126.

Jackson, M., Hampson, G., Pain, C. and Gorman, G. (2015) Reservoir modelling for flow simulation: surface-based representation of geologic heterogeneity and space-and time-adaptive unstructured meshes, in *Recognising the Limits of Reservoir Modelling – and How to Overcome Them (Abstracts volume)*, Petroleum Group, Geological Society of London.

Keith, B.D. and Pittman, E.D. (1983) Bimodal porosity in oolitic reservoirs – effect on productivity and log response, Rodessa Limestone (Lower Cretaceous), East Texas basin. *AAPG Bulletin*, **67**, 1391–1399.

King, P.R. (1990) The connectivity and conductivity of overlapping sand bodies, in *North Sea Oil and Gas Reservoirs II* (eds A.T. Butler *et al.*), Graham and Trotman, London, pp. 353–358.

Krige, D.G. (1951) A statistical approach to some basic mine valuation problems of the Witwatersrand. *Journal of the Chemical, Metallurgical and Mining Society of South Africa*, **52** (6), 119–139.

Leahy, G.M. and Skorstad, A. (2013) Uncertainty in subsurface interpretation: a new workflow. EAGE. *First Break*, **31**, 87–93.

Leverett, M.C. (1941) Capillary behaviour in porous solids. *Transactions of the AIME*, **142**, 159–172.

Long, A., Bingwen, D. and Kajl, B. (2002) *PESA– Technical Focus*, Petroleum Exploration Society of Australia.

Lucia, F.J. (1983) Petrophysical parameters estimated from visual description of carbonate rocks: a field classification or carbonate pore space. *SPE Journal of Petroleum Technology*, **35**, 626–637.

Lucia, F.J. (1999) *Carbonate Reservoir Characterization*, Springer-Verlag, Berlin.

Lucia, F.J. and Conti, R.D. (1987) Rock fabric, permeability and log relationships in upward shoaling, vuggy carbonate sequence. Geological Circular No. 87-5, Bureau of Economic Geology, University of Austin, Texas.

McNaughton, D.A. and Garb, F.A. (1975) Finding and evaluating petroleum accumulations in fractured reservoir rock, in *Exploration and Economics of the Petroleum Industry*, vol. **31**, Matthew Bender & Company Inc, Miamisburg, OH.

Morecambe, E. and Wise, E. (1971) Morecambe & Wise Christmas Special, BBC, London.

Mountney, N.P. (2006) Eolian facies models, in *Facies Models Revisited* (eds H.W. Posamentier and R.G. Walker), SEPM **84** (Society for Sedimentary Geology), Tulsa, OK.

Nelson, R.A. (1992) *An Approach to Evaluating Fractured Reservoirs*, Society of Petroleum Engineers, Richardson, TX, JPT, September, pp. 2167–2170.

Nugent, W.H., Coates, G.R. and Peebler, R.P. (1978) *A New Approach to Carbonate Analysis*. Transactions of the Society of Professional Well Log Analysts 19th Annual Logging Symposium, Paper O.

Nurmi, R.D. (1984) *Carbonate pore systems: porosity/permeability relationships and geological analysis* (abstract). Presented at AAPG Annual Meeting, San Antonio, TX, 20–23 May.

Pitchford, A. (2002) 3D Modelling: size and shape do matter! PESA–Technical Focus, Petroleum Exploration Society of Australia: August/September: 78.

Posamentier, H.W. and Walker, R.G. (eds) (2006) *Facies Models Revisited*, SEPM **84** (Society for Sedimentary Geology), Tulsa, OK.

Rapid Reservoir Modelling Consortium (2017) *Reducing Uncertainty with Interactive Prototyping Geology*, www.rapidreservoir.org (accessed 26 October 2017).

Ringrose, P.S. (2008) Total property modelling: dispelling the net-to-gross myth. *SPE Reservoir Evaluation and Engineering*, **11**, 866–873.

Ringrose, P.S. and Bentley, M. (2015) *Reservoir Model Design*, Springer Science+Business, Dordrecht, Netherlands.

Saka, G.H., Castro, E., Pettan, C. *et al.* (2015) Stretching the limits of reservoir modelling: an integrated approach from the Peregino Field, Brazil, in *Recognising the Limits of Reservoir Modelling- and How to Overcome Them (Abstracts volume)*, Petroleum Group, Geological Society of London.

Skelt, C. and Harrison, B. (1995) *An Integrated Approach to Saturation Height Analysis*. Transactions, SPWLA, 36th Well Annual Logging Symposium, Paris, France, NNN1-10.

SPE (P.R.M.S.) (2011) *Petroleum Reserves Management System*, Society of Petroleum Engineers, Richardson, TX.

Speers, R. and Dromgoole, P. (1992) Managing uncertainty in oilfield reserves, in *Middle East Well Evaluation Review*, Schlumberger Oilfield Services.

Steele, R.P., Allan, R.M., Allinson, G.J. and Booth, A.J. (1993) Hyde: a proposed field development in the southern North Sea using horizontal wells, in *Petroleum Geology of Northwestern Europe: Proceeding of the 4th Conference* (ed. J.R. Parker), The Geological Society, London, pp. 1465–1472.

Sweet, M.L., Blewden, C.J., Carter, A.M. and Mills, C.A. (1996) Modeling heterogeneity in a low-permeability gas reservoir using geostatistical techniques, Hyde Field, Southern North Sea. *AAPG Bulletin*, **80/11**, 1719–1735. American Association of Petroleum Geologists.

Thomas, J.M. (1998) Estimation of ultimate recovery for UK fields: the results of the DTI questionnaire and a historical analysis. *Petroleum Geoscience*, **4**, 157–163.

Tyler, N. and Finley, R.J. (1991) Architectural controls on the recovery of hydrocarbons from sandstone reservoirs, in *Concepts in Sedimentology and Palaeontology*, vol. **3**, SEPM, Tulsa, Oklahoma, pp. 1–5.

Vail, P.R., Mitchum, R.M. Jr, Todd, R.G., Widmier, J.M., Thompson, S. III, et al. (1977). Seismic stratigraphy and global changes of sea level. *AAPG 26*.

Webb, S.J., Revus, D.E, Myhre, A.M., Goodwin, N.H., Dunlop, K.N. and Heritage, J.R. (2008) *Rapid Model Updating with Right-Time*

Data – Ensuring Models Remain Evergreen for Improved Reservoir Management. SPE112246, Intelligent Energy Conference, Amsterdam, Netherlands.

Weber, K.J. (1986) How heterogeneity affects oil recovery, in *Reservoir Characterization* (eds L.W. Lake and H.B.J. Carroll), Academy Press, Orlando, FL, pp. 487–544.

Weber, K.J. and van Geuns, L.C. (1990) Framework for constructing clastic reservoir simulation models. *Journal of Petroleum Technology*, **42**, 1248–1297.

Wehr, F. and Brasher, L.D. (1996) Impact of sequence based correlation style on reservoir model behaviour, lower Brent Group, North Cormorant Field, UK North Sea Graben, in *High Resolution Sequence Stratigraphy: Innovations and Applications*, vol. **104** (eds J.A. Howell and J.F. Aitken), Geological Society of London Special Publication, London, England, pp. 115–128.

Worthington, P.F. (2002) Application of saturation-height functions in integrated reservoir description, in *Geological Application of Well Logs* (eds M. Lovell and N. Parkinson), American Association of Petroleum Geologists, Tulsa, OK AAPG Methods in Exploration No.13, pp. 75–89.

A

Introduction to Reservoir Geostatistics

(After Karl Kramer)

This short appendix is designed to familiarize geoscientists with the principles and methods used to model heterogeneity by investigating the critical questions:

- When and what type of heterogeneity matters to fluid flow?
- What types of data can help us build a model?
- Should we use stochastic or deterministic methods?
- How do I know that the model is any good?

My thanks go to Karl Kramer, a colleague at Roxar many years ago, whose course on geostats both informed me and I hope now the reader!

Although it is impossible to avoid use of equations, it is not the intention of this appendix to give a dreary list, equation by equation, of the variety of tools available. Rather we hope to focus on the central themes – correlations, trends, interpolation and simulation. We will strive to get a clear and distinct general understanding of these concepts. By getting a mental picture of what these are and by looking at several applications of these in practice, we intend to put the user in a stronger position to decide what aspects of heterogeneity modelling are likely to be useful in any particular case and what strategy to be adopted in planning a reservoir model. The appendix is about the concepts of heterogeneity modelling and is not linked to any particular set of software – although indications of where to find any techniques that are discussed will be given.

Geostatistics is a relatively new branch of statistics for the analysis of spatially organized data. Krige and Sichel in South Africa and Matheron in France first developed the tools of geostatistics in the

Reservoir Modelling: A Practical Guide, First Edition. Steve Cannon.

1960s. The motivation for this development was the analysis of spatially oriented data from gold-mining operations. Application of geostatistical techniques soon became popular in the mining industry at large. Now, these techniques are applied in many diverse fields including forestry, meteorology, image analysis, telecommunications, environmental remediation and so on.

The concepts and mathematical definitions that make up geostatistics have been refined and added to over the years. Geostatistics is now recognized as an important tool in the capture of reservoir heterogeneity for the purpose of dynamic reservoir simulation. It provides a robust methodology for the analysis of uncertainty and risk in geological modelling. It also serves to provide methodologies for the integration of diverse data sets that are sampled at very different scales, such as petrophysical and seismic data.

In answer to the question 'Why geostatistics?' the answer is because heterogeneity matters and affects fluid flow in the reservoir: as heterogeneity increases, sweep efficiency decreases. However, this is not the only reason that geostatistics is important to the understanding of a petroleum reservoir. Geostatistical tools are used to integrate geological, geophysical and engineering data in ways that account for the differing scale, reliability and resolution of these data. The integration of data into a spatially consistent model will often lead to new interpretations of these data. Also, by allowing for an understanding of the range of possibility in parameter distribution, given the current state of knowledge, geostatistical techniques allow for risk assessment regarding a range of issues associated with reservoir exploration and development.

Elementary statistical tools such as histograms, descriptive and ANOVA statistics, and/or scatter plots are utilized as data are brought to the model as both screening tools for data quality and to provide some of the model parameters such as facies thickness distributions and facies proportion which are employed during facies modelling. Analysis of trends, spatial continuity and covariance are integral to the petrophysical modelling process. There are several important methodologies that can be employed to stochastically distribute reservoir parameters. These can be applied at both the facies and the petrophysical stages of model development.

There is a common misconception that the use of geostatistics makes the modelling process easier. There is nothing yet developed that can substitute for the inductive reasoning of an experienced human brain. There are many subjective decisions that must be

made during the process of data analysis and model design. That said, the proper application of geostatistical techniques in the 3D realm will produce better geological models and can lead to a better understanding of reservoir dynamics.

A.1 Basic Descriptive Statistics

Although basic statistics have been recognized usefully descriptive and analytic tools for hundreds of years, it is only in recent decades that it has become common to categorize geological data sets in this manner. There are some common and useful algorithms that can be used to summarize nearly any quantitative data set. These algorithms include the measures of central tendency such as mean, mode and median. Measures of the spread in data value include variance, standard deviation and interquartile range and measures of symmetry include the coefficient of variation and coefficient of skewness.

The *mean* is a familiar measure of central tendency. The formula is simply:

$$m = \frac{1}{n}\sum_{i=1}^{n} x_i$$

The *median* is the midpoint of the observed values if they are arranged in increasing order. It is equal to the value of the middle observation, where middle is defined on the basis of the number of measurements. This can be written as:

$$M = \left\{ \begin{array}{c} \mathrm{mod}\left(\frac{n}{2}\right) = 1 \rightarrow x_{\frac{n+1}{2}} \\ \mathrm{mod}\left(\frac{n}{2}\right) = 0 \rightarrow \frac{x_{\frac{n}{2}} + x_{\frac{n}{2}+1}}{2} \end{array} \right\}$$

When the number of observation is odd, the value of the $((n+1)/2)$th measurement is the median. When the number of observations is even, the average of the $(n/2)$th and $((n+1)/2)$th measurements is called the *median*. The median is not as sensitive to erratic high data values as the mean and a large difference in the two statistics is an indication that there are outliers in the data.

The *mode* is simply the value that occurs most frequently. This definition can be problematic in that the frequency of occurrence depends on the precision of the data. By rounding to a different number of significant digits, the count, and hence the mode, will change. For this

reason, the mode is seldom used in describing data sets with several significant digits, as are common in geological data.

Data sets with various different spreads in value can have the same statistics of central tendency as illustrated (Figure A.1).

Variance is a measure of spread given by the average squared difference of the observed values from their mean.

$$\sigma^2 = \frac{1}{n}\sum_{i=1}^{n}(x_i - m)^2$$

As it involves squared differences of the observed values, variance is sensitive to outliers in the data. In order to report spread in the same units as the mean, it is common to take the square root of variance. This is referred to as the *standard deviation*.

As described above, the median is the value of the $(n/2)$th measurement. Similarly, the value of the $(n/4)$th and $(3n/4)$th measurements represent the first and third quartiles of the data. The difference in these values is a measure of the spread, which does not utilize the mean as the centre of the distribution and is therefore not as affected by outliers in the data. This difference is referred to as the interquartile range.

Central tendency and spread are two attributes of a data distribution, but do not provide information about the symmetry of a distribution about the centre. Examples of asymmetric distributions are shown in Figure A.2. The distribution on the left, with the long tail to the left, is referred to as having negative skewness. The one on the right, with the long tail to the right, is referred to as having positive skewness.

A common measure of skewness is the coefficient of skewness as follows:

$$C_{\text{skewness}} = \frac{\frac{1}{n}\sum_{i=1}^{n}(x_i - m)^3}{\sigma^3}$$

This measure is highly affected by outliers in the data. For this reason, skewness is often only described as positive or negative.

One other measure of skewness that can be used with positively skewed, positive data is the *coefficient of variation*. It is defined as the ratio of the standard deviation to the mean.

$$CV = \frac{\sigma}{m}$$

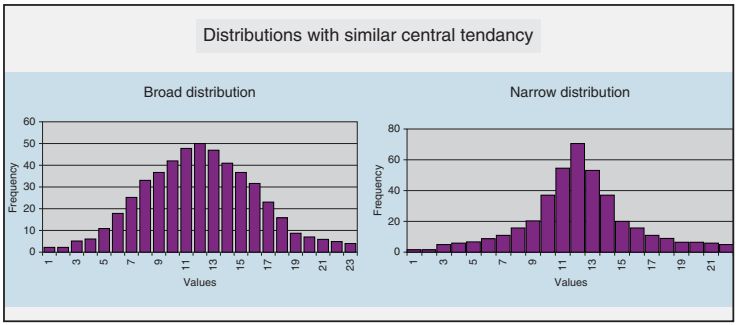


Figure A.1 Examples of two data sets with different normal distributions but with a similar central tendency.

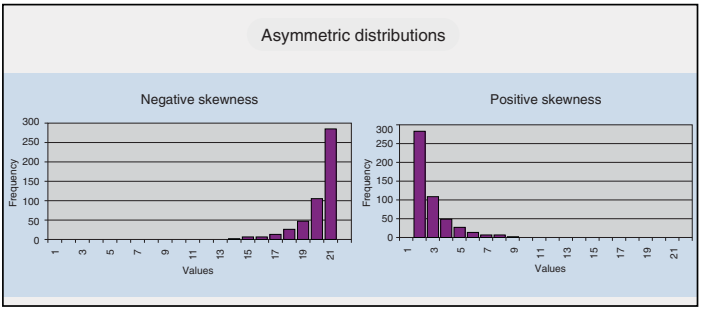


Figure A.2 Examples of asymmetrical distribution with positive and negative skewness.

If estimation is going to be attempted with a data set, the coefficient of variation can be used to screen for problems. A coefficient of variation greater than 1 indicates the presence of some erratic high sample values that may have a significant impact on estimation.

A.2 Conditional Distributions

It is often the case that measurements of natural processes or products are interrelated to one another. Measurements of the neutron density of a rock and the gamma ray emission intensity of that same rock will often change in an inverse relationship. Although the actual measurements may be independent of each other, the materials they measure are related by depositional process. In fact, the relationships exhibited by independent but related data reveal much information about the underlying processes at work in the distributions of multivariate data.

As with the description of univariate data by univariate descriptive statistics, the relationships present in a multivariate data set can be summarized with bivariate statistics. Scatter plots provide a visual representation of the relationship, if any, between two variables; these are simply created by plotting one variable against another as illustrated (Figure A.3).

The relationship between variables illustrated by a scatter plot provides a quick way to identify outliers that might otherwise go undetected. Although not every outlier is due to error, it is important to investigate and understand the reason outliers exist.

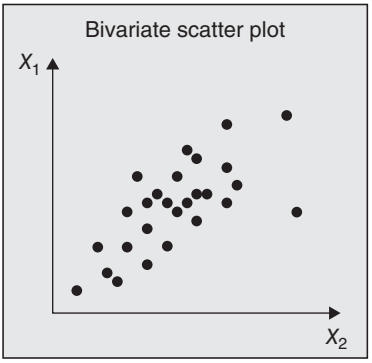


Figure A.3 A bivariate scatterplot provides a way to display a relationship between two variables.

The relationship between variables illustrated by a scatter plot is most often summarized by the correlation coefficient as follows:

$$\rho = \frac{\frac{1}{n}\sum_{i=1}^{n}(x_i - m_x)(y_i - m_i)}{\sigma_x \sigma_y}$$

The numerator is referred to as the *covariance*. Note that the covariance is dependent on the magnitude of the data values. The correlation coefficient will always have values from −1 to 1. A +1 correlation coefficient indicates that the scatter plot exhibits a line with positive slope and a −1 indicates that the line will have negative slope. Data with a correlation coefficient near zero may exhibit a cloud on a scatter plot, but this is not the only pattern possible. The correlation coefficient measures the linear relationship, but data with non-linear relationships may have very low correlation coefficients.

A.3 Spatial Continuity

Geological data are often measured at specific coordinates in space. Petrophysical data, for instance, has an x, y and z coordinate for every measurement. Although discontinuities at all scales exist in nature, intuitively one expects that many rock properties will not change abruptly. Porosity between the grains of an ancient beach sand, for example, would not be expected to change abruptly from one location to another, but rather change slowly reflecting the scale of the hydraulic conditions that controlled the deposition of sand grains originally. This implies that the values of many geological measurements will be related to similar measurements nearby.

If a measurement at one location is plotted against similar measurements at some fixed distance (h) from the first measurement, a scatter plot of these measurements can be created (Figure A.4).

At small separation distances, the measurements should be nearly the same, and as such fall on a 45° line. As the separation distance increases, the 'fatness' of the data cloud around the 45° lines will increase. A convenient summary statistic for these special scatter plots is the moment of inertia about the 45° lines calculated as follows.

$$\text{moment of inertia} = \frac{1}{2n}\sum_{i=1}^{n}(x_i - y_i)^2$$

In this context of spatial correlation, the moment of inertia is referred to as the *semi-variogram*. Of course, as the value of the semi-variogram

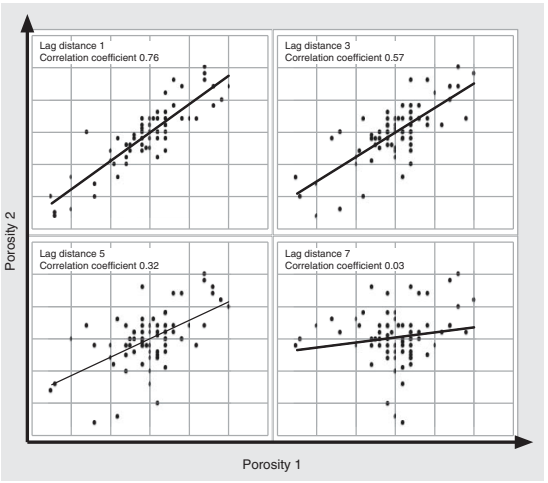


Figure A.4 Different scatterplots describing how a property varies with distance from a given point; the correlation becomes weaker as the distance increases.

increases, the value of the correlation coefficient for the same scatter plot will decrease.

The discussion of **h** scatter plots above assumes that there are many measurements at each finite separation distance. Most geological data sets have measurements scattered about spatially or at some regular interval in *x*, *y* or *z*. Because of the sparse sampling, it is common to gather points for the semi-variogram from an interval of separation distances, referred to as the *lag tolerance*. The absolute separation distance at one half the lag tolerance is referred to as the *lag increment*.

If the semi-variogram values at different separation distances or lag increments are plotted relative to the separation distance, a continuous function can be estimated. This function is referred to as the *variogram*.

A.3.1 Variogram Description

At small separation distances (h), the value of the variogram function exhibits its lowest z value. If this value is zero, it means that the measurements are identical when taken at the same location. The semi-variogram value at zero separation distance is referred to as the *nugget*. As the separation distance increases, the difference between samples increases at a rate determined by the function itself. At some distance, called the *range*, further increases in the separation distance have no effect on the difference between measurements. The range is the distance beyond which measurements are spatially uncorrelated. The z value of the variogram at $h >$ range is referred to as the *sill*. This can be shown to be equivalent to the variance of the measurements themselves (Figure A.5). Note that the variance near the origin increases most rapidly with the exponential model and most slowly with the Gaussian model (Figure A.6).

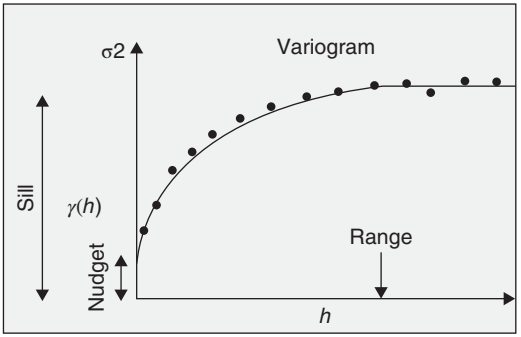


Figure A.5 Schematic diagram of an ideal variogram with an explanation of the main features: sill, nugget and range.

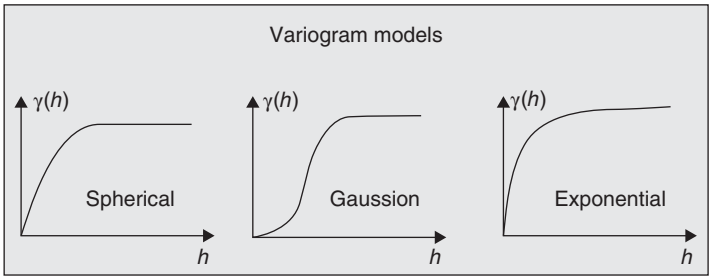


Figure A.6 Different experimental variogram models commonly used in geostatistics.

A.3.2 Zonal and Geometric Anisotropy

The correlation range of geological data is often dependent on orientation. There are countless examples of processes that are directionally oriented. Beach sand, for example, that is prograding seaward will contain small-scale laminations that are very continuous along the strike of the shore but very discontinuous perpendicular to shore. When the correlation range changes with orientation, this is referred to as geometric anisotropy. It is also possible that the sill will change with orientation. This is referred to as zonal anisotropy. When modelling in three dimensions, the anisotropy can be represented by an ellipsoid (Figure A.7).

A.3.3 Variogram Estimation

The variogram model is usually estimated by first constructing a sample variogram from the available data set, utilizing some lag tolerance to account for the spatial distribution of samples in the modelling domain.

It is important that the data utilized to estimate a variogram should be taken from a single genetic or digenetic population. As was mentioned earlier, the spatial continuity of porosity in a hypothetical fossil beach sand would not be expected to change abruptly because the hydraulic conditions that caused the depositional sorting of the sand are not expected to change abruptly. If that sand is subsequently cut by fluvial channels and then backfilled with silty sand, the sand in the fluvial channels would exhibit different population attribute statistics reflecting a different depositional regime. The transition from one sand population to another would be very abrupt as a

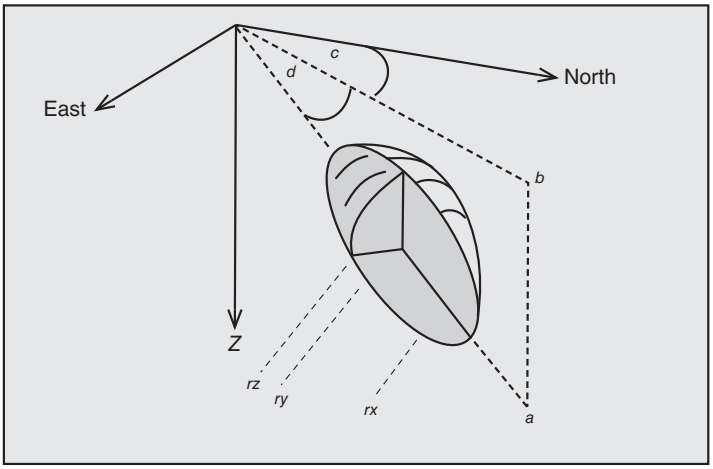


Figure A.7 Three-dimensional ellipsoid of variogram range used to represent directional anisotropy; major, minor and vertical directions require a description of the range, sill and nugget.

result of cross cutting by the fluvial system. If porosity measurements from different populations are combined in the estimation of the sample variogram, the estimated range will probably be reduced, but most importantly, the abrupt transition from one population to the other will be lost in any extrapolation or simulation. This problem is normally handled by either object or indicator modelling of the depositional scale heterogeneity before the modelling of population distributions.

In order to correctly estimate any population statistics, it is necessary that data are gathered stratigraphically and not by depth or time. The importance of this consideration is illustrated in Figure A.8. Note that the lower layer present at the location of the well on the left are not present at the location of the well on the right in the case of parallel bedding, but are present everywhere with proportional bedding.

Three-dimensional extrapolation and simulation occurs in a rectilinear simulation space. The structure of the grid is transformed to this space and, subsequent to the simulation, is back transformed to the original structural space (Figure A.9).

As simulation and extrapolation is performed in the 'simbox', it is necessary to transform the input data to the simbox before estimating the variogram parameters. A simple kriging algorithm (discussed

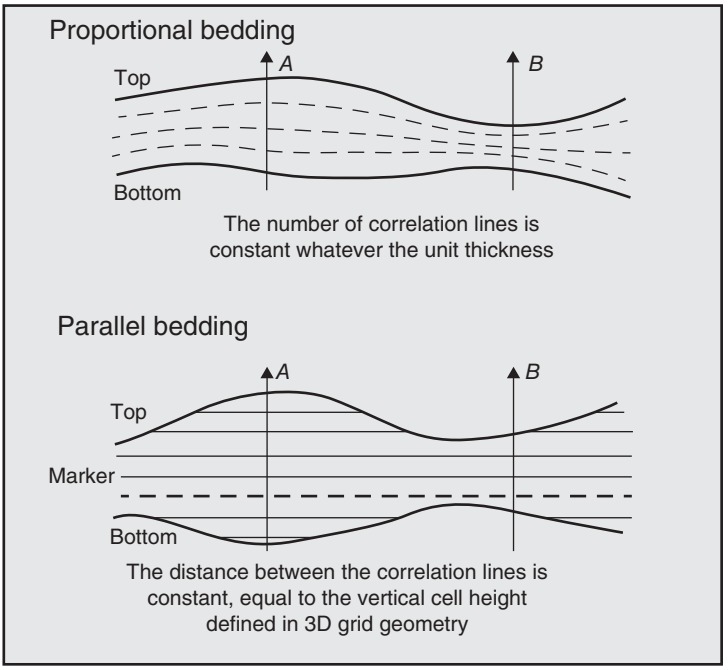


Figure A.8 The impact of bedding on the distribution of properties is seen in well B in which some layers are not sampled in the constant cell thickness example.

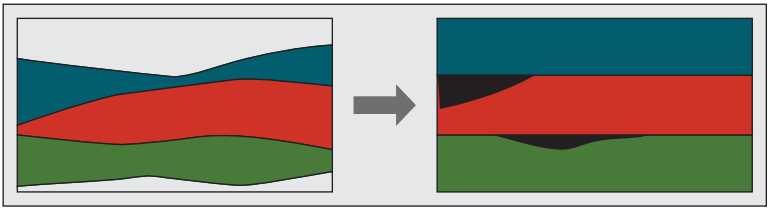


Figure A.9 Most geostatistical methods require a transformed or rectangular grid. The data must be transformed to the grid, calculate the experimental variogram and for kriging and simulation.

below) is used in simulation that requires that the data are normally distributed with a mean of 0 and a standard deviation of 1. This is accomplished during the analysis of the blocked data by the application of trends and transforms as applicable.

A.4 Transforms

As will be discussed in Section A.7, there is an implicit assumption with both extrapolation and simulation that the variable under consideration is a random variable that behaves normally. This means that the input data distributions need to be normal. With simple kriging, there is also the assumption that the expected value of the variable is stationary across the modelling volume. This variable condition is met by transformation before simulation.

There are usually a number of transformation tools available in the modelling software. These tools can transform any data set to meet the criterion of the kriging algorithm. Scatter plots of the variable against the x, y and z directions relative to the modelling simbox and also relative to discrete objects within the modelling simbox can be examined for any trends in the data. These trends can be estimated by simple linear regression lines or by piece-wise linear regression. The equation of these lines is retained to both transform the data before simulation and back transform the data post simulation. The trends can also be applied with a pixel-based approach, utilizing two- and three-dimensional matrices.

The Box–Cox function is available to transform highly skewed data to symmetric distributions. Logarithmically distributed data can be transformed utilizing a logarithmic function. Once the data are symmetric, it can be shifted such that the mean value is zero and rescaled such that the standard deviation is 1. The back transformation of the simulated field will guarantee that the resulting realization honours the moments of the original data.

If blocked well data are available that represents the full and complete range of the target distributions, an empiric method is available which will bin the input blocked well data and map it, bin by bin, to a standard normal distribution or normal score.

A.5 Lag Definition

Once data have been blocked to a stratigraphic grid, filtered by facies and transformed to normal space, three-dimensional lag intervals and tolerances are chosen to estimate variogram values as a function of separation distance. Initially, the data gather should be omnidirectional. If the horizontal data can be interpreted, then the lags can be refined to account for directionality (Figure A.10).

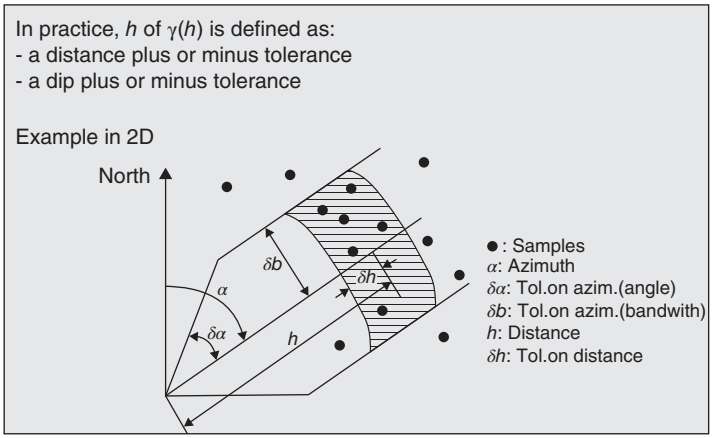


Figure A.10 A variogram search window used to estimate 3D lag intervals and tolerances to account for anisotropy.

The tolerance on maximum width of the lag box insures that data gathers will have directionality. The tolerance on the azimuth insures directionality at small separation distances. To create an omnidirectional data gather, one would set the tolerance on the azimuth to 90° and the tolerance on the bandwidth to equal one half of the lag tolerance.

A.6 Variogram Interpretation

In the petroleum industry, well spacing is typically orders of magnitude greater than the vertical spacing between petrophysical measurements in the well bores. As a result, there are more data pairs per lag interval in the vertical direction and therefore the vertical estimations are less subject to sampling error. Also, because the petrophysical measurements are typically taken at regular intervals, data groups tend to be evenly dispersed between lag intervals. It is common to see sample variograms that closely match the form of the basic variogram models, whereas the horizontal variograms appear erratic and difficult to interpret.

Interpretation of the horizontal variograms must be done with consideration to the sample distribution and significance. It may be more exacting, in some situations, to estimate the horizontal variogram models from analogue data (e.g. taken from outcrop).

Not all 'erratic' sample variogram behaviour is due to sampling deficiency. An understanding of the sample variogram behaviour can lead to new insight about the nature of the underlying measurement.

The presence of a sill implies that the expected value (mean) of the measurements remains the same, no matter where the measurements may be clustered spatially. This condition is referred to as stationarity. If there is a trend in the mean value of the data, caused by a dipping surface for instance, then sample variograms will not exhibit a sill in the direction of change (Figure A.11).

Hole effects are indicative of a periodicity in the data (Figure A.12). The variogram is highly sensitive to outliers and something akin to a 'hole effect' can also be created by the existence of outliers.

If the vertical sill is higher than the horizontal, this could be indicative of layering in the data. If the vertical sill is less than the

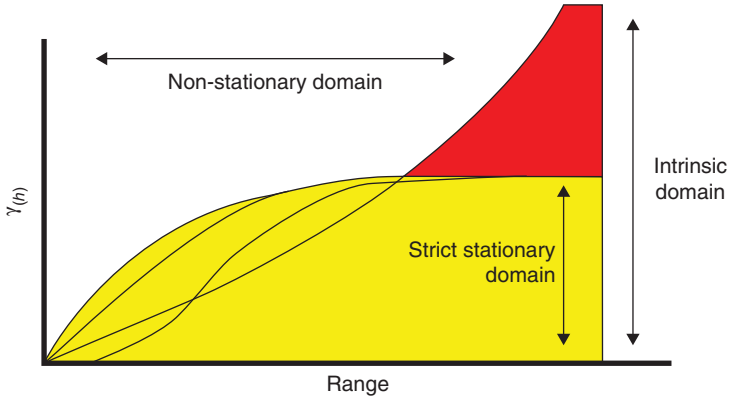


Figure A.11 Where a sill is recognized, it implies that the mean value of the measurement remains same, regardless of clustering: the data are therefore stationary. If there is a trend remaining in the data after transformation, then no sill will be recognized.

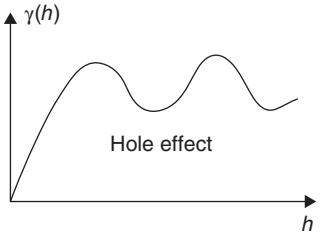


Figure A.12 The recognition of a hole effect in the experimental variogram indicates a periodicity in the data.

horizontal, this could be indicative of differing mean values between wells or sub-regions.

As a practical matter, while either extrapolating or simulating a distribution of spatial data based on the variogram model, the model is utilized to weight the existing data as a function of distance from the point under consideration. Therefore, it is the shape of the variogram model near the origin that will have the greatest impact on the results of simulation or extrapolation. Much effort can be expended estimating the shape of the variogram near the sill, with little added value to the final simulation. It is important to understand the meaning of the effects described above from the standpoint of data QC, but the practitioner should feel empowered to exercise geological judgement in the interpretation and modelling of the variogram.

A.6.1 Indicator Variograms

The question sometimes arises as to how to create a variogram of facies data. Facies are discrete, which means they can only take on integer numbers. To subtract one facies code from another would be as meaningless as to ask the question 'What is a channel minus an overbank?' It is necessary to rephrase the question to be 'What is the probability of finding facies Y at this location, given the existence of facies X at that point?' The probability of transition from one discrete number to another is itself a continuous real function, no different than the variograms discussed above.

As the probability function of interest refers to probability relative to the current facies location, it must be constructed from binary data: zero to indicate the current facies and one to indicate another facies code. Each facies transition pair will have its own indicator variogram. Recall the formula for the semi-variogram.

$$\lambda = \frac{1}{2n} \sum_{i=1}^{n} (x_i - y_i)^2$$

If our data consist of only zeros and ones, it can be quickly shown that the maximum sill will be 0.25. This will only occur in the situation where there are two facies of equal global proportion. In the event, more than two facies are present or the proportions of a binary pair are not equal, the maximum sill is reduced by the formula

$$\lambda_{\max} = (\text{proportion } A)(1 - \text{proportion } A)$$

where A is the facies to which transition probability is calculated.

A.7 Kriging

All geologists are familiar with the contouring of map data. When this is done by hand, the eye of the mapmaker guides the interpolation between known values. Since the advent of computers, numerous algorithms have been devised to perform interpolation based on various weighted functions of the existing data. Like many other algorithms, kriging interpolates based on a weighted average of the existing data. By utilizing the variogram to calculate those weights, kriging has the ability to incorporate anisotropy as part of the weighting process.

One property of kriging that sets it apart from other interpolation techniques is that it creates the best linear unbiased estimate (B.L.U.E.). It creates the 'best' interpolation in the sense that it minimizes the estimation error. It is unbiased in the sense that the mean estimation error is zero; in other words, the tendency to underestimate is no different than the tendency to overestimate. The statement that kriging is B.L.U.E. is conditional on the assumption that the variable under consideration can be simulated by a random function which is Gaussian in nature.

The derivation of the kriging equations is steeped in mathematical jargon and requires an understanding of calculus, random functions and matrix algebra.

It is not necessary to be a mechanic to drive a car, and in the same manner, it is not necessary to understand the derivation of the kriging equations to utilize algorithms based on these equations. It is important to understand that the mathematics of kriging is at the heart of many common simulation methodologies, and as such is one of the foundations of geostatistics.

A.7.1 Simple and Ordinary Kriging

As stated above, the kriging produces the B.L.U.E. for each point under consideration. The fundamental difference between the two methods is that simple kriging requires the expected (mean) estimate value stay constant anywhere in the area of investigation (AOI), whereas ordinary kriging re-estimates the mean at every interpolation point.

Ordinary kriging has been called the workhorse of geostatistics because of its ability to account for drift in the expected value of the data. For this reason, ordinary kriging is usually the first tool of choice for interpolating a set of dispersed data. However, the ability to

account for drift can create problems honouring global distributions when used as the basis of simulation.

Like all interpolation algorithms based on the weighted average of available data, kriging creates a smooth interpolation between the existing data. Unlike most interpolation algorithms, however, kriging can account for anisotropy in the spatial variance of the data. In Figure A.13a–c, the top surface was created utilizing an inverse distance algorithm, whereas the surface in the middle was created from the same data set utilizing simple kriging with an isotropic variogram. The first two images interpolate in much the same way, whereas the image on the bottom is notably affected by a northeast-southwest orientation. This image was constructed with kriging and an anisotropic variogram.

The weights given to input data values are constrained to sum to one with ordinary kriging. For this reason, ordinary kriging is not sensitive to spatial clustering in the data distribution.

A.7.2 Kriging with a Drift

Rather than estimating the local mean in the neighbourhood of the interpolation point on the basis of known point, the mean can be estimated as the sum of a local component and a regional drift. This allows information contained in secondary data such as seismic attribute maps and volumes to be incorporated in the estimation of values at each interpolation point. A correlation coefficient that measures the strength of the relationship between the primary and secondary variable is used to control the emphasis placed on the secondary variable in estimating the local mean.

Although kriging with a drift is an efficient algorithm for the incorporation of secondary data, it will reflect the variability of the secondary variable at any large distances from primary data.

A.7.3 Co-kriging

Co-kriging utilizes the cross-variograms between secondary and primary data to populate a full matrix of primary and secondary spatial covariance and cross-covariance. As such, this algorithm will honour the spatial variability of the primary variable while at the same time utilizing the information of the secondary variable to condition the interpolation. Co-kriging matrices grow very quickly as the number of input data increases. Full co-kriging is typically subject to limitations

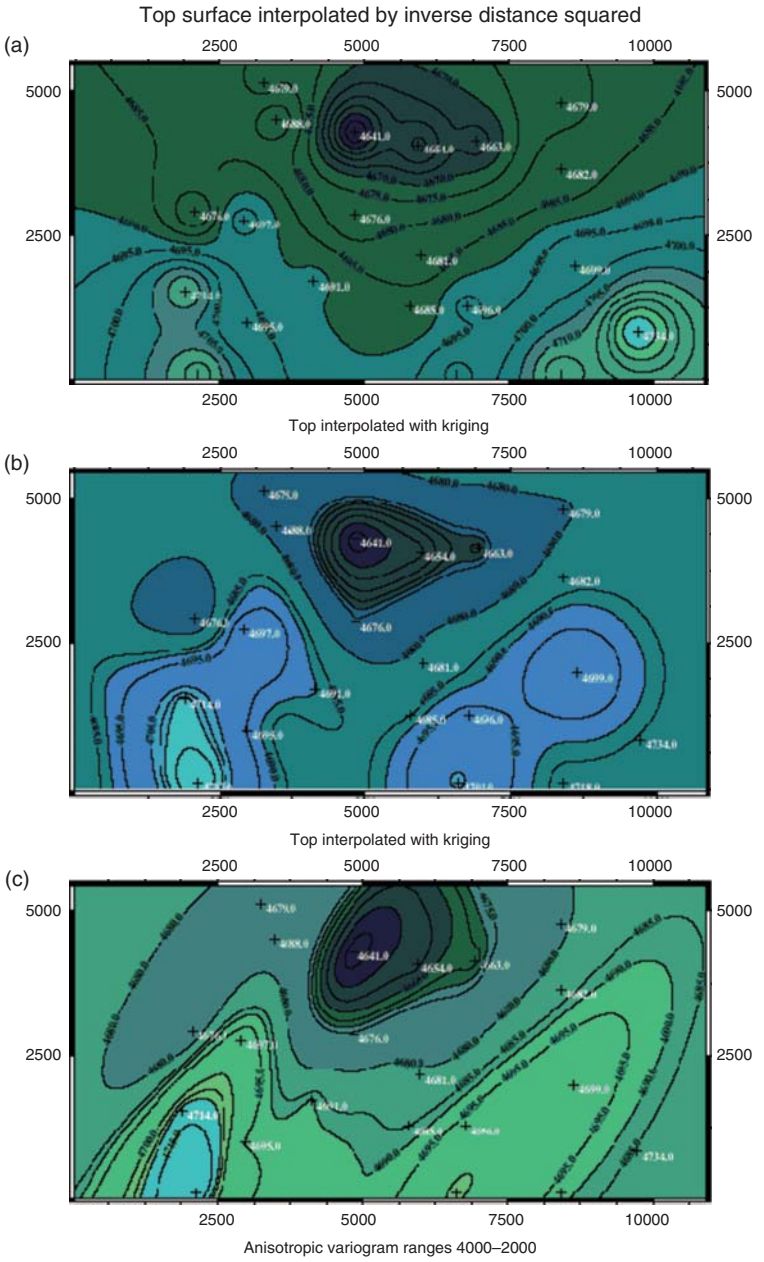


Figure A.13 Examples of different mapping algorithms: (a) inverse distance squared interpolation; (b) kriging; (c) a surface kriged using an anisotropic variogram.

on the number of input data it can practically be used with. Because of this, a simplified algorithm was developed which only considers the secondary data that is co-located with the primary data. Co-located co-kriging is more frequently the algorithm employed for estimation, rather than full co-kriging, particularly when used as the engine of a simulation technique.

In most cases where primary data are closely spaced relative to the correlation range, the difference between the interpolation values of co-located co-kriging and kriging with an external drift are subtle. This is because, in this circumstance, the primary data 'screens' the effect of the secondary variable.

A.7.4 Indicator Kriging

In most geological setting, rock properties can be grouped into populations that are genetically related. These genetic (depositional) units have geometries and are, thus, spatially correlated. The question arises as to how these spatial relationships can be honoured in the interpolation of facies distributions.

Indicator kriging methodologies utilize simple kriging to estimate the probability of a facies transition utilizing indicator variograms. Indicator kriging is the common engine of indicator simulation methods. These methods are most applicable when the density of well information is greater than the average size of facies belts or objects. In this situation, the shapes of facies objects are fairly well defined by hard data.

In situations where input data are sparse or non-existent, object modelling techniques are more predictive in the sense object models incorporate geometric information about the facies, whereas indicator methods rely solely on the two-point statistics of the indicator variogram.

A.8 Simulation

There are many interpolation algorithms that can be used to estimate values between known data. The most common algorithms involve the use of spline functions, distance weighting or some form of kriging. All of these algorithms will honour the data and base estimates on some weighted average of the data. This means that all of these functions will create smooth transitions from one point to the next. Although smooth maps may be aesthetically pleasing to the eye, they

do not replicate the variability that may exist at scales smaller than the space between data points. By modelling the variogram, we have modelled the variance at all scales, but because the kriging estimation is always the expected value at a point, the variance at a point is never utilized. Most simulation algorithms utilize a random draw from the conditional distribution at a given point to estimate the value. This constrained randomness models the variance at all scales and therefore produces spatial distributions that can vary from realization to realization and yet always honour the data and the variogram (Figure A.14).

The simulation does a much better job, visually, of representing the actual data than the kriged estimates. It honours the variogram, indicating that the information regarding spatial variance has been captured. As a result of honouring the spatial variance model, the distribution of values in the realization also matches the input data distribution. Note that kriging did not honour that distribution.

The ability of simulation techniques to capture the variance (or heterogeneity) of a data distribution has important implication to the simulation of fluid flow in petroleum reservoirs. Small-scale heterogeneity has a pronounced effect on the tortuosity of streamlines and, as such, effects drainage or sweep efficiency.

Finally, if multiple realizations of the distribution are created, the differences in those realizations will quantify the reliability of the estimations at any specific point.

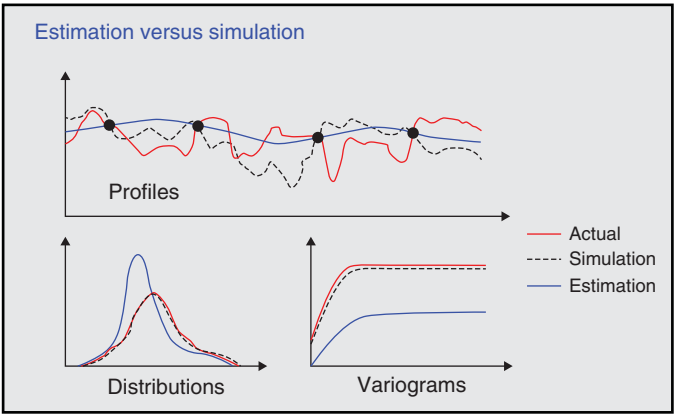


Figure A.14 Simulation draws randomly from the conditional distribution introducing randomness in the result.

All of the sequential simulation algorithms are implemented in similar ways. The basic idea is to generate a conditional distribution at the point under consideration and then randomly draw from that distribution. Subsequently move to another (usually random) point and again generate a conditional distribution, but include all the previously estimated values with the original hard data in conditioning the new distribution (Figure A.15).

The algorithms utilized to generate the conditional distribution are numerous. All of the simulation algorithms discussed below, with the exception of object modelling, utilize one of the various kriging algorithms to generate the mean and standard deviation of a conditional normal distribution or conditional cumulative density function (ccdf).

A.8.1 Sequential Gaussian Simulation (SGS)

Sequential Gaussian simulation utilizes simple kriging to estimate the mean and variance of the conditional normal distribution from which to draw at each point. This algorithm is applicable to continuous variables such as clay volume. It is necessary to transform the input data distribution such that, after transformation, it is normal. Subsequent to simulation, the realization is back transformed utilizing the inverse of whatever transformations have been applied to the input data. By the use of two- and three-dimensional trend transforms to the data, before the empiric normal score transform, it is possible to incorporate secondary data such as net trend maps as additional constraint in the simulation (Figure A.16).

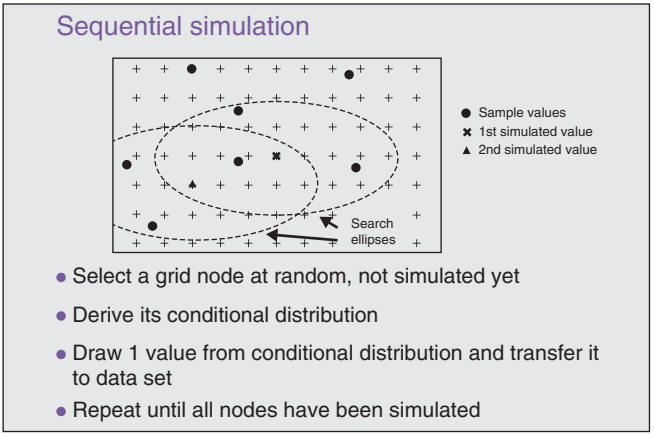


Figure A.15 A schematic diagram of the sequential simulation method.

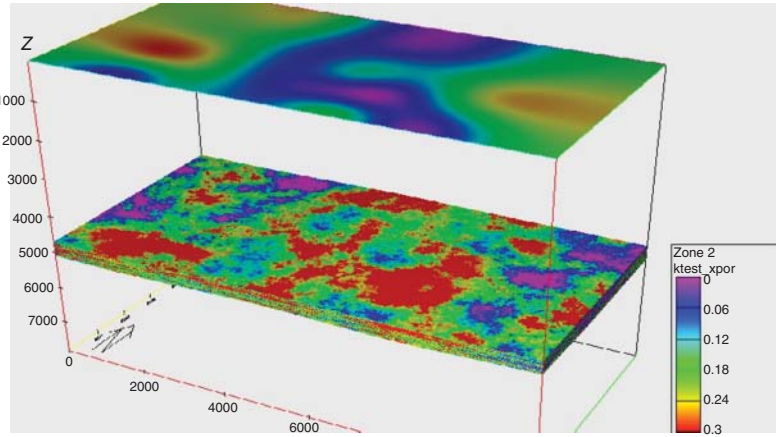


Figure A.16 An example of sequential Gaussian simulation (SGS) where a kriged map of porosity is applied to constrain the simulation result.

It should be noted that the introduction of an external trend would alter the target distribution from that which is estimated from well data alone.

A.8.2 Sequential Gaussian Simulation with External Drift

Sequential Gaussian simulation with external drift utilizes kriging with external drift to estimate the mean and variance of the conditional normal distribution from which to draw at each point. Recall that kriging with external drift utilizes the matrices of ordinary kriging but contains an additional term to account for the secondary trend. This term alters the expected value of the distribution on the basis of secondary data that is defined throughout the model volume.

Some software tools utilize a fast sequential screening algorithm for stochastic petrophysical simulation. This operates by first simulating without well control on a coarse grid. This establishes the large-scale heterogeneity utilizing the variogram range and nugget parameters. The distribution is assumed to be a standard normal distribution with a mean of 0 and a standard deviation of 1. This coarse grid is then utilized as input data for simulation of finer and finer grids until the entire grid has been populated. The screening algorithm requires that the populated grid be kriged to the well control to insure that well data are honoured. This is done automatically as the final stage of simulation.

Back transforms are applied to the realization to replicate the trends and distributions of the input well data.

While simulating correlated variables such as porosity and permeability, the first variable in the modelling list is simulated and the second variable is simulated using the first variable as external drift. Figure A.17 illustrates the outcome of simultaneous porosity and permeability simulation.

A.8.3 Sequential Indicator Simulation (SIS)

Sequential indicator simulation utilizes indicator kriging to estimate the ccdf for each specific facies and combines these to create the ccdf for all facies at a specific point.

This is a useful tool to simulate the distribution of large-scale (e.g. flow zone indicator) discrete information. It is most useful when the inter-well spacing is less than the average size of individual facies objects. When well control is sufficiently dense, the size and orientation of individual facies objects will be constrained by the data, without the need of additional constraint or definition.

Sequential indicator simulation can incorporate trends in the calculation of the ccdf. Adding the additional constraint to the kriging equations that the sum of sample weights times the facies probability equals the probability from the trend does this.

$$\sum_{\alpha=1}^{n} \lambda_\alpha(u;k)p(u_\alpha;k) = p(u;k)$$

The use of trends allows data such as seismic attributes to be utilized in constraining the distribution of large-scale facies. This requires mapping the attribute values to probabilities, one array for each facies. The probability arrays must sum to 1 at every point.

A.8.4 Sequential Co-located Co-simulation (SGCoSim)

Sequential Gaussian co-located co-simulation utilizes the co-located co-kriging estimator to derive the mean and standard deviation of the ccdf at each point. This tool is particularly applicable to situations where the primary variable exhibits short-range heterogeneity that is substantially different than that of the secondary variable. If a very high-resolution seismic attribute appears to respond to changes in sand quality, it may be possible to distribute porosity at the resolution of the modelling grid stochastically and use the seismic to directly

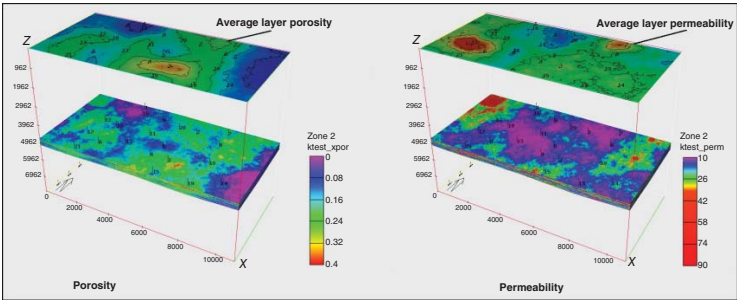


Figure A.17 The outcome of simultaneous porosity and permeability simulation.

guide the estimated values while honouring the short range variability modelled by the variogram of the primary variogram. Figure A.18 illustrates co-located simulation of porosity and permeability utilizing the same data as was used to illustrate sequential Gaussian simulation with a drift shown above.

A.8.5 Sequential Indicator Co-located Co-simulation

Again, this is based on the associated kriging equations defined earlier. Indicator kriging does not utilize all of the information available within the local search radius. Because it looks at the transition probabilities on facies at a time, the statistical inference that could be made by the presence of other facies is ignored.

As indicator co-kriging is utilized to evaluate discrete data that is generally derived from the data set, most of the time indicator co-kriging or its co-located cousin will not improve the results significantly in terms of modelling heterogeneity.

A.8.6 Truncated Gaussian Simulation (TGSim)

Geologists have long recognized patterns of deposition caused by rising or falling relative sea levels. In the late 1970s, Van Wagoner, Vail *et al.* published on the conceptualization of sequence stratigraphy (Vail *et al.*, 1977). Numerous papers have been published since about principles of sequence stratigraphy and its application to real-world data interpretation. The fundamental unit of sequence stratigraphy is the sequence, which is bounded by unconformities and their correlative conformities. These sequences are further subdivided into system tracts that are defined by the stacking patterns of parasequences bounded by marine flooding surfaces or the time equivalents.

The sequence stratigraphic framework provides a means to relate time equivalent facies spatially. It has been noted that seismic reflections often follow chronostratigraphic correlation patterns rather than time-transgressive lithostratigraphic units (Vail *et al.*, 1977). There are many circumstances when it will be desirable to construct grids that mimic the chronostratigraphy of a unit and model the time-transgressive units as belts. These 'belts' are then utilized to constrain the spatial distribution of individual facies objects. Distributary channel objects can be constrained to the 'fluvial' belt for instance. The resulting sands will then inter-finger with more marine facies, mimicking the rock geometries resulting from changes in relative sea level or baseline.

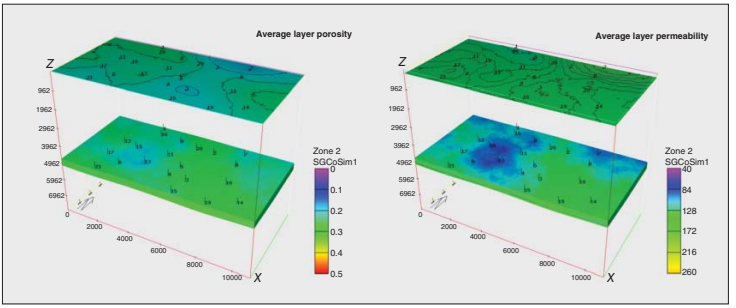


Figure A.18 Illustrates co-located co-simulation of porosity and permeability utilizing the same data as was used to illustrate sequential Gaussian simulation with a drift shown above.

Truncated Gaussian simulation (TGSim) with trends is used to generate discrete patterns similar in geometry to parasequences. Although the function was inspired by the need to model parasequences, it is certainly not limited to that purpose. In some cases, the algorithm can provide an efficient means to distribute and condition any transitional facies. It is a probability field simulation method, not unlike the sequential indicator simulation method discussed above. Each facies is modelled as an interval within a continuous 3D random variable that is truncated by one or more threshold values. The continuous 3D variable is modelled as a Gaussian field that is the sum of a linear expectation function and a stationary residual Gaussian function. The linear expectation function ensures that the facies below and above one facies are always different. The linear expectation field sets up the general shape and progradational angle of the belts model. The seaward direction can be established from regional geological setting and sequence stratigraphic studies. It controls the direction of facies tract elongation (Figure A.19).

The aggradation angle of each parasequence can be estimated from well data by examining lateral and vertical facies changes or can be measured from analogue outcrops. High aggradation angles lead to the simulation of laterally restricted facies tracts, whereas low angles lead to the simulation of continuous, sheet-like facies tracts. Aggradation angles range from 0.50 for highly aggradational parasequence to 0.010 for strongly progradational parasequences. The probability field that the equation above defines is modified to conform in a general (regression) sense with the existing belt data derived from well control.

The degree with which this process alters the form of the probability field is a function of the well density and the variance allotted the residual function. Low well density or high residual variance will result in initial probability fields that closely resemble that described by the equation directly above.

As a final process, the probability field is perturbated by a residual function that is simulated in a Gaussian space. The residual component of the 3D continuous field is specified by its variance and variogram. Together they control local facies continuity and the degree of inter-fingering between each. A large variance and short correlation length produce thinner and shorter facies units, whereas large variance and short correlation length produce thinner and shorter facies units. The variance can be estimated by first examining the vertical distance between most belt transitions represented in the wells

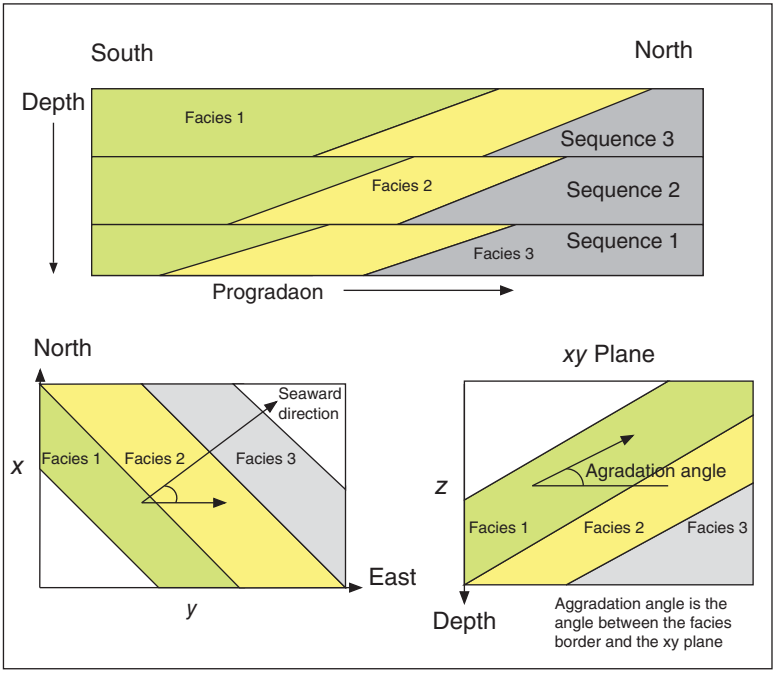


Figure A.19 Schematic representation of TGSim with trends used to model progradational facies belts.

and the corresponding transitions in the unconstrained probability field.

The vertical correlation lengths reflect bed thickness, which can be approximated by average bed thickness. Horizontal correlation lengths reflect continuity of the inter-fingering in the horizontal plane. The longest axis of the anisotropic ellipse should be parallel to the shoreline strike and normal to the seaward direction.

After the addition of the residual Gaussian field to the prior probability field, the continuous field is truncated to the nearest integer values, which represent distinct geological belts.

A.9 Object Modelling

Heterogeneity is a function of scale in most reservoirs. At the scale of typical petroleum reservoirs, the heterogeneity can be divided into

facies and petrophysical scales. The heterogeneity caused by facies transitions is sometimes modelled with indicator methods such as the SIS method described above. Most indicator methods today are based on uniform fields of transition probability, one unique field for each field. This binary statistical description of facies distribution cannot capture information about facies geometry. Geologists have been studying depositional processes and cataloguing geometrical information about depositional facies for many decades. This collection of secondary analogy data, in general, is what allows geologists to make educated guesses about trends and interpolation values 'better' than most simple contouring algorithms. Object modelling provides a method by which geological data on facies relationships and geometries can be used to condition a stochastic distribution of facies.

Examples of objects include sinuous channels, elliptical reefs, fan-shaped crevasse splays and so on. Many of these objects have conditional transition probabilities that are dependent on the presence or absence of other specific facies in the local neighbourhood. Crevasse splays, for instance, are found in conjunction with channels due to the genetic connection between the two. Likewise, coral reefs are never found in the neighbourhood of distributary channels, due to fact that coral require clean water to live. In addition, secondary data derived from well control, seismic and or other sources can aid in constraining the distribution of facies.

Most software tools have two different algorithms to conditionally distribute objects in space. Both algorithms iterate, placing one object, and then evaluating whether to accept or reject the new object. After iteration, both algorithms evaluate whether or not to repeat the process. The algorithms differ substantially in how they converge and how the accept/reject decisions are made. Elementary object modelling continues until it achieves the volume fraction of each facies in the model volume subject to rules such as maximum number of iterations. Conditioning data such as well information and trend data are used in calculating the keep/reject decision independently of each other and the global volume constraints. The alternative algorithm utilized in channel object modelling calculates the value of an objective function after each iteration. If this value increases from the previous iteration, the object placement is rejected. The objective function is a complex function of all the conditioning data and therefore accounts for all constraints simultaneously (Figure A.20).

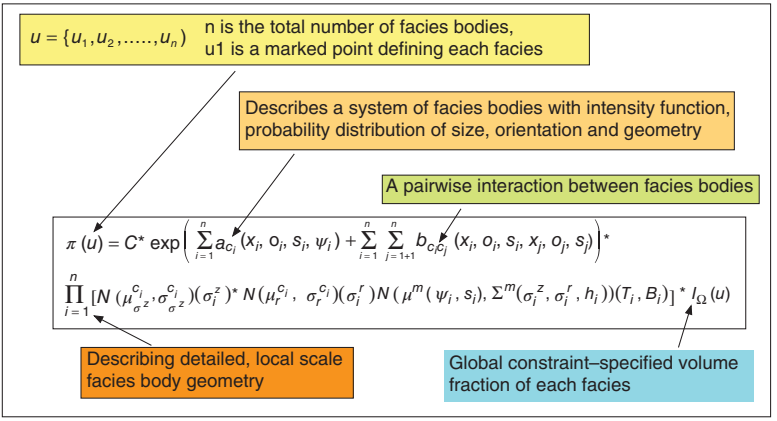


Figure A.20 The objective function describes the total probability of simulated facies body configuration after each iteration. The aim is to optimize the value of this function.

A problem with rejecting object placement based on an increase in the objective function is that it is possible to settle into local minima of this function. This problem is solved by a method known as simulated annealing. The name is derived from the metallurgical field where steel, for instance, is annealed by quenching the hot metal in cold water. Annealing freezes the iron and carbon atoms into the structure that existed at the temperature of quenching. As atoms have more freedom of movement relative to each other at higher temperatures, quenching at high temperatures 'freezes' the atoms in a more random state than slow cooling. The probability of accepting a new object into the model volume is initially unconstrained. As the program iterates and places new objects into the modelling domain, the probabilities of acceptance are increasingly conditioned, mimicking the effect of cooling in the annealing process.

In object modelling, crisp geological objects are parameterized; based on the object parameters, distribution functions are given that can be sampled, for example, height, width:height ratio, direction and sinuosity (Figure A.21). Objects are simulated using a marked point process where the object centre is placed using a 'marked point process' and the object shape is sampled from the parameter distributions. An object is rejected if it contradicts surrounding well information (unsuitable if many wells exist) and the process is repeated until a certain NTG or number of objects is simulated. It is possible

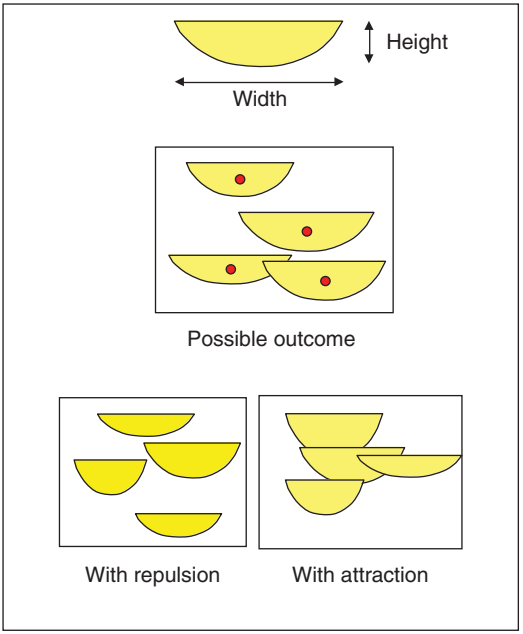


Figure A.21 A simple representation of the object modelling process taking the height and width of an object and the starting point at a well location, with possible outcomes based on attraction or repulsion rules.

that extra rules can be honoured, such as a hierarchy of erosion, or attraction and repulsion to mimic low and high connectivity; only object modelling implicitly models connectivity between sand bodies.

A.10 Summary

A wise man once said 'There are three types of lies: lies, damned lies and statistics'; in reservoir modelling, this could be paraphrased as there is 'hard data, soft data and geostatistics' and you need all three elements to successfully distribute facies and properties in a 3D grid. Although the originator of the quote is debateable, one person who certainly used it is Mark Twain; he also came up with a complementary quotation that may be useful to the modeller, 'it is easier to fool people, than to convince them they have been fooled'.

Index

Reservoir Modelling: A Practical Guide, First Edition. Steve Cannon.

d

e

f

S

WILEY END USER LICENSE AGREEMENT

Go to www.wiley.com/go/eula to access Wiley's ebook EULA.