Chapter 22

Introduction to Reservoir Modelling

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22.1 Introduction

This chapter gives the reader an overview of the basic elements in reservoir modelling.

Reservoir modelling is the process of transferring the available subsurface data and knowledge into a digital (computerised) numerical representation of the subsurface, and is now considered an essential part of understanding and developing oil and gas resources. Reservoir models are used for calculation of initial volumes in place, optimisation of drainage strategy for a hydrocarbon field, calculation of recoverable volumes, generation of production profiles, evaluation/generation of depletion plans, and as a planning tool for detailed placement of production and injection wells. Due to the multidisciplinary input and the increased options for advanced visualisation, digital 3D geological models are important as a collaborative working tool for the integration of different subsurface disciplines (Figs. 22.1 and 22.2).

Digital reservoir models may serve different purposes, and we typically distinguish between *static reservoir models* and *dynamic reservoir models*.

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22.1.1 The Static Reservoir Model

The static reservoir model is usually referred to as the geological model (often abbreviated "geomodel"), and is a digital numerical model describing the initial state of the reservoir before any production of hydrocarbons has taken place, i.e. representing the spatial distribution of rock types with different reservoir properties. Hence, a major task for the static model is calculating the initial in-place volumes of hydrocarbons, which is a quantification of what is "down there", without consideration of recovery method or economical viability. These volumetric calculations can be performed for an entire reservoir or individually for any layers or fault segments that have been defined during model construction.

22.1.2 The Dynamic Reservoir Model

The dynamic reservoir model is typically based on the framework and spatial distribution of reservoir properties from the static reservoir model. Equations for fluid flow in porous media are applied in order to simulate the distribution/movement of reservoir fluids as a function of production and/or injection. The dynamic reservoir model also takes into account changes related to varying reservoir pressure and hydrocarbon saturation as a function of production/injection over time. Fluid properties, such as density, viscosity, phase equilibrium and fluid mobility, interact with changes in pressures and fluid saturations.

To summarise, the static model will estimate the natural in-place volumes in the subsurface, while the dynamic model will predict what is recoverable. What

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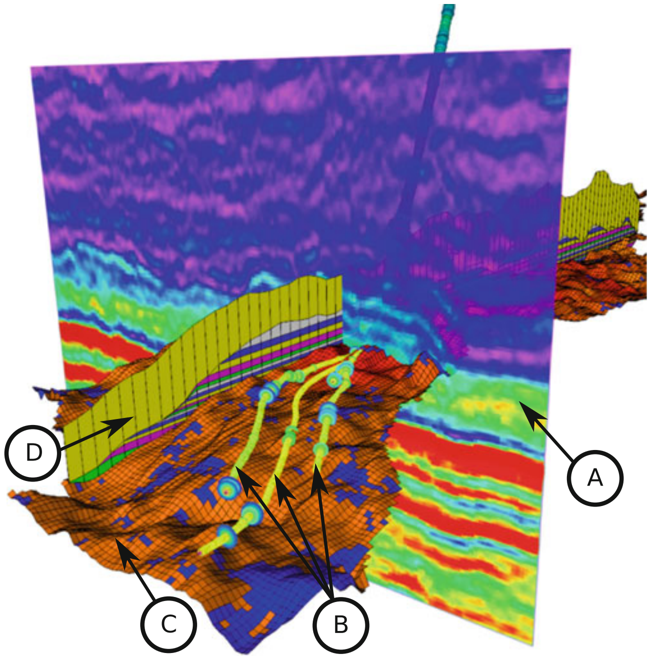

Fig. 22.1 3D modelling tools are excellent for co-visualisation of multiple data types. Here is an example from a Norwegian offshore field, displaying (A) seismic data, (B) wells, (C) static model grid with properties, and (D) dynamic grid with properties. The visualization is improved by contemporary use of visual techniques like various fence slices and partial transparency

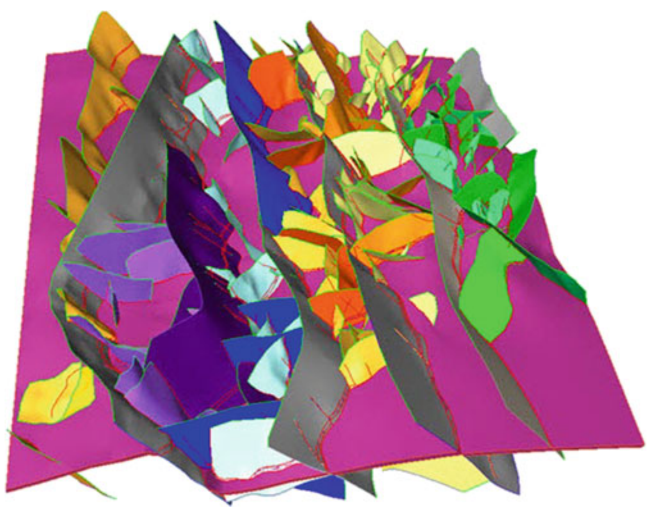

Fig. 22.2 The Gullfaks field (offshore Norway) is heavily faulted. The reservoir model shown here displays all faults included in the model work

is recoverable will be dependent on various factors, including the production costs, and there are many large accumulations of hydrocarbons that are simply too expensive to recover given current expectation of future oil and gas prices.

22.1.3 Main Model Elements

Both the static model and the dynamic model may be split into two major elements:

- The reservoir container (bulk volume) limiting the spatial distribution of the reservoir. The reservoir interval is defined by stratigraphic surfaces/layering and faults, represented by a three-dimensional grid.

- The property model, defining how petrophysical reservoir properties and other relevant properties are distributed in three dimensions within the reservoir container/grid. It usually also includes a numerical description of the spatial distribution of the reservoir fluids, e.g. oil and/or gas saturation (through water saturation modelling).

To provide high quality input to a model, it is important to stress that a reservoir model represents a synthesis of several sub-surface disciplines' description and understanding of the reservoir. The goal is to establish a common model that can be used for determining and optimising the commercial value of a hydrocarbon accumulation. Close communication, co-operation, and planning between the involved disciplines are key points for constructing a successful model that is useful for its intended purposes. As there are many ways to create a digital model, having a clear and well defined business objective for the modelling effort is another important success factor. Disciplines that typically are involved with modelling are petrophysics, various disciplines in geology (such as sedimentology, petrography, diagenesis, stratigraphy, biostratigraphy, geochemistry and structural geology), geophysics, production technology, reservoir engineering, statistics and computer sciences. Due to the major implementation of reservoir models in the oil industry in the last two decades, being a "geomodeller" or "reservoir modeller" has become a discipline by itself.

22.2 Model Planning

Before starting any modelling work there are some fundamental questions that need answers, as model work may be time consuming and requires significant manpower. One should also collect all possible data and knowledge of the reservoir to be modelled, including experience from previous models. Hence, proper model planning is important before starting the actual model work.

22.2.1 Business Objectives

The process of constructing a new reservoir model should always start by defining the business objectives, e.g. why are we making a reservoir model? What is the purpose of the model? What kind of questions is the model going to provide answers to? Business objectives may vary substantially depending on where an individual field is in its life cycle. Here are some examples of modelling objectives and the consequences to the scope of the work:

- Calculating oil or gas in-place volumes. This objective is often the most important in the exploration and early field development phase. Generally, it implies the use of more simplistic models with less focus on the detailed architecture of the reservoir. Usually, several alternative models are made to capture volume uncertainty (see Sect. 22.5).
- Calculating recoverable volumes and establishing production profiles. This objective becomes a priority in the field development and production stage. It generally requires a more detailed and sophisticated description of reservoir architecture and distribution of reservoir properties to be able to simulate how fluids are flowing through the reservoir during production. A common way to calibrate the models with production data is so-called history matching (Sect. 22.4.3).
- Optimising the depletion plan for a field. This objective is tightly linked to the previously described business objective and therefore has many of the same requirements. The depletion plan describes how to optimally drain the reservoir. This includes not only optimising the recoverable reserves, but also the economy of the field in question. Some typical aims of depletion planning could include:
  - Evaluating depletion vs. gas and/or water injection.
  - Optimising number of wells.
  - Evaluating well geometries, e.g. vertical, slanted or horizontal wells. Would it be economical or beneficial to use branched wells?
- Well planning. This objective may demand an even higher degree of detail in the reservoir model.

22.2.2 Input Data and Databases

There are numerous data sources that can be utilised for reservoir modelling (Fig. 22.3). Examples of important data are given in the following sub-sections.

22.2.2.1 Geophysical Data

The dominant geophysical input to reservoir modelling is seismic data. Other geophysical data

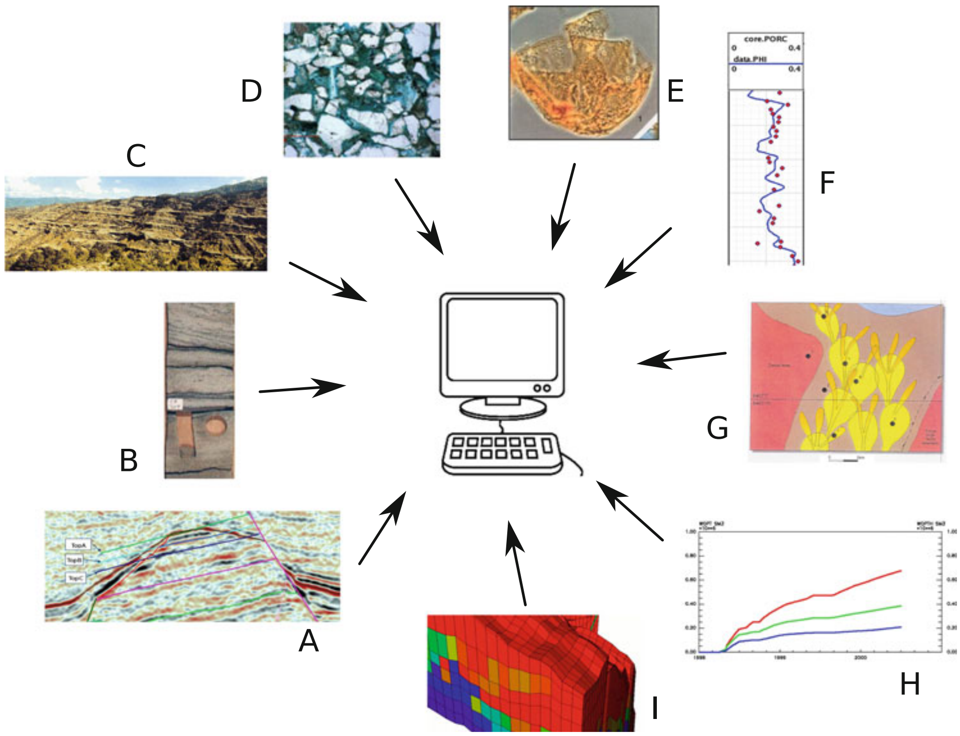

Fig. 22.3 Reservoir models integrate many data sources. These include seismic data (**a**), core data (**b**), outcrop analogues (**c**), thin sections (**d**), biostratigraphy (**e**), well logs and correlations (**f**), concept models (**g**), production data (**h**), and earlier reservoir models (**i**). These data originate from various subsurface disciplines at different scales, abundance and quality

such as magnetic, electromagnetic or gravity analysis are currently of less importance. Data from seismic surveys includes:

- Interpreted horizons and faults, usually depth converted (Fig. 22.3a).
- Seismic inversion data that provide important information on rock properties, e.g. porosity and fluid distribution.
- 4D seismic data provide additional crucial information on reservoir behaviour during production, for instance connectivity and segmentation.

22.2.2.2 Petrophysical Data

Well log data are a fundamental input to reservoir modelling. It is important to acknowledge that well logs do not give petrophysical data such as porosity, saturations and permeabilities directly; rather all these data types are the result of some kind of processing of basic well logging tools. For example, porosity logs will be derived from density, sonic or neutron logs, while saturations are computed from resistivity logs or NMR (see Chap. 16). The following logs and core-derived data are the most important for reservoir modelling:

- Porosity logs derived from petrophysical well log measurements (usually the density log) and core data (Fig. 22.3f).
- Microscopic images (thin sections and SEM) and laboratory analysis (XRD) for mineralogy and pore geometries taken from core samples (Fig. 22.3d).
- Horizontal permeability logs derived from petrophysical well log measurements, core data, and well testing.
- Input on vertical permeability (often expressed as the Kv/Kh ratio between vertical and horizontal permeability), from log analysis, core analysis, and lamina bed modelling.
- Petrophysical lithology curves, often referred to as “flag” curves, such as calcite-cement flags, coal flags and reservoir flags. The flag logs are important in petrophysical evaluation to improve the determination of reservoir parameters. For instance, the use of resistivity logs to compute hydrocarbon saturations is only valid in intervals flagged as

"net reservoir". The reservoir flag is an indication of which intervals (based on petrophysical criteria) may be regarded as reservoir, or non-reservoir, intervals.
- Input to fluid and saturation models – such as saturation logs, saturation height functions, fluid contacts, and fluid properties.

All logs are associated with a variable degree of uncertainty. Permeability logs are regarded as more uncertain than porosity logs, and horizontal wells have usually less accurate measurements than vertical wells (Chap. 16).

22.2.2.3 Geological Data

Geological data and analysis embraces a wide variety of input to reservoir models, both quantitative and qualitative. It is vital to understand the genesis and depositional signature of the subsurface interval of interest, in order to delineate the overall architecture of the reservoir. For example, the geological data input could be:

- Reservoir zonation and sedimentological description, including identification of flow units (modelling facies, see Sect. 22.3.3.4) and barriers. Sedimentological core descriptions are a very important input here.
- Various stratigraphic models, including sequence stratigraphic models and lithostratigraphic models (Chaps. 7 and 8). This also includes palogeographic maps which may be quite important for understanding trends and architectural topology within reservoir units in the model construction.
- Evaluation of compaction and diagenesis, including impact on reservoir property distribution (see Chaps. 4 and 21).

22.2.2.4 Reservoir Technical Data

Reservoir technical data includes data that are related to dynamic understanding of the reservoir. Typical reservoir technical data are:

- Pressure data, both those observed prior to production and the pressure development during production.
- Various fluid data and PVT data, such as viscosities, fluid densities, B_o, B_g (shrinkage factors for oil and gas), etc.
- Well test data and production history in general. These data are usually applied during calibration of reservoir model, known as history matching (Sect. 22.4.3).

22.2.2.5 Databases and Data Management

All data input to reservoir modelling need to be easily accessible. A database is an organised collection of data, and includes digital data as well as paper reports. The purpose of a database is to provide efficient retrieval for the task to be performed – in this case reservoir modelling.

A major challenge is that data need to be thoroughly quality checked prior to modelling as even apparently small errors in parameters such as well data may be magnified when propagated into the models, which in turn can lead to erroneous models and hence wrong decisions with large financial consequences.

The subsurface database may be vast. Seismic data alone requires enormous amounts of data storage. A common problem is that different software products have their own databases, and transferring data between different databases and applications can be demanding. As software tools are upgraded, data import and export formats may change, and new data types may be required.

Working with the database prior to the actual modelling is an important and time consuming task, and sometimes the database preparations and quality control may take more resources than the actual modelling. It is important to acknowledge this early in the model planning, to avoid delays and errors in the actual modelling.

22.2.3 The Conceptual Model

The conceptual model can be defined as a synthesis of our understanding of the reservoir targeted for modelling, based on all available input data from all the subsurface disciplines (see Sect. 22.2.2). In many cases, it will also be crucial to include additional information, such as well data from neighbouring fields, regional models and understanding, experience from analogue producing fields, and/or outcrop data. Typically the conceptual model can be summarised with a number of drawings and qualitative descriptions prior to the modelling.

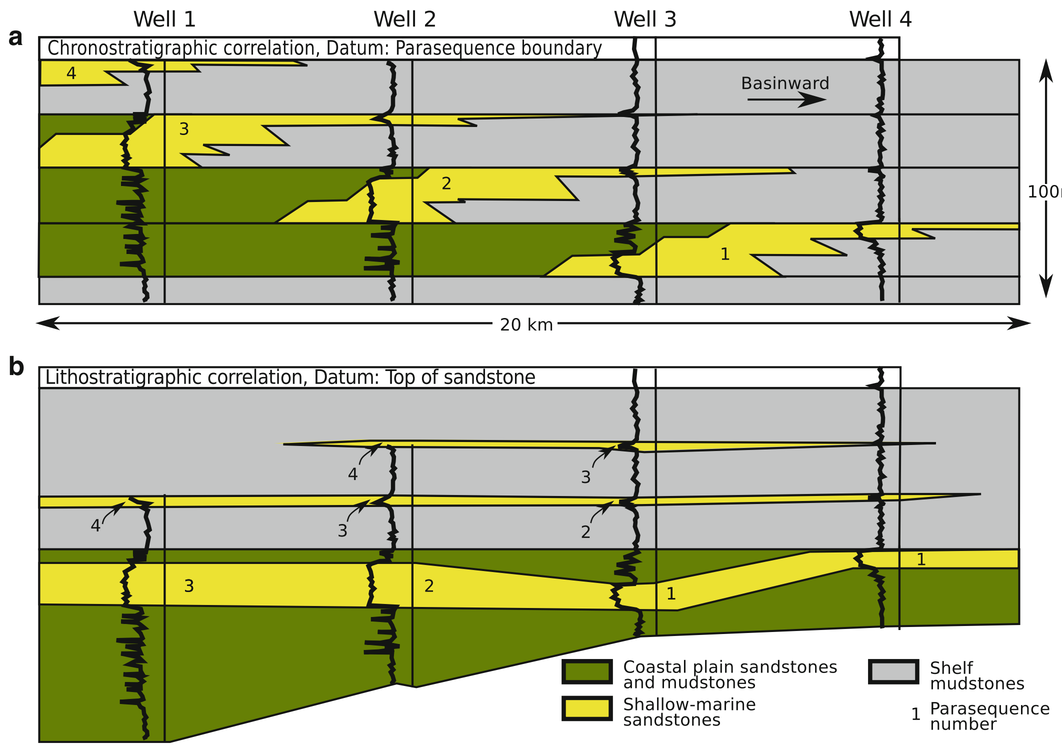

Fig. 22.4 Comparison of (**a**) chronostratigraphic and (**b**) lithostratigraphic correlation styles [modified from van Wagoner et al. (1990)]. Picking the "correct" correlation of sand units will significantly affect flow patterns. Hence it is critical for the reservoir model to have a solid conceptual model as basis

22.2.3.1 Sequence Stratigraphy and Architectural Elements

The conceptual model is an important "driver" for the resulting digital model, and understanding the link between stratigraphy and reservoir architecture is essential. Figure 22.4 illustrates how a sequence stratigraphic correlation will alter the reservoir connectivity dramatically compared with a simpler lithostratigraphic correlation. Using the concept sketches as guidelines for the modelling is important, and comparing the initial concept drawings with the digital result is a valuable exercise (Fig. 22.5). However, it is important to acknowledge that the concept itself has significant uncertainties, and the modelling process (e.g. the data analysis, Sect. 22.3.3.3) can reveal information that may force a revision of the conceptual model. Thus it is common that the uncertainty of the concept model is tested by building alternative models (see Sect. 22.5).

22.2.3.2 Link Between Geology and Petrophysical Properties

In addition to positioning architectural elements in the 3D model, it is important to understand and predict how mineralogy and diagenesis will affect the petrophysical properties in the reservoir. The diagenetic processes, taking an unconsolidated sediment to a rock is thoroughly discussed in Chap. 4, and many aspects in this process are important considerations when constructing a model.

The mineralogy, grain size, sorting and post-burial chemical processes have huge effects on porosity, permeability, saturation and wettability. These properties impact both on static volumes and dynamic flow behaviour in the reservoir. For example, the relative permeability functions are quite important for the dynamic flow (see Chap. 21), and they depend heavily on fluid properties, pore shape, sorting, grading, grain coating minerals, cement types, mechanical strength and microfractures. These, in turn, are functions of primary mineralogy, diagenesis and the basin burial

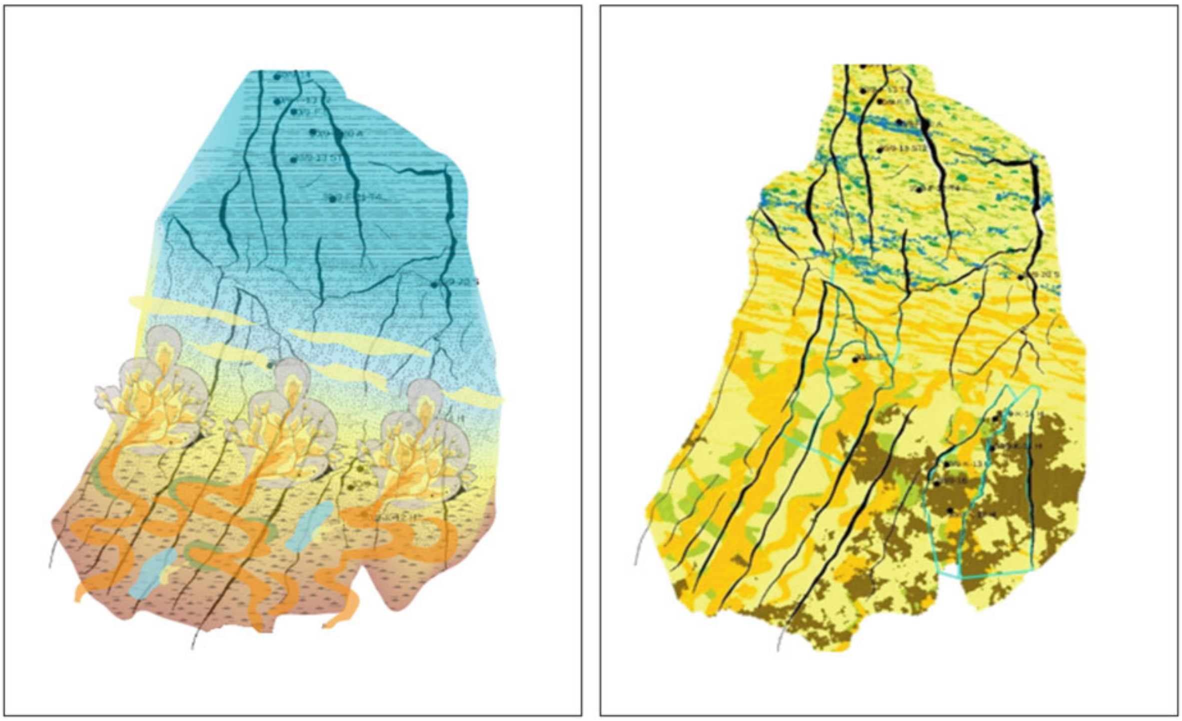

Fig. 22.5 Conceptual model for a reservoir interval in Oseberg Sør, compared with a digital model realisation. The conceptual model (*left*) is a hand-drawn sketch, while the computer model (*right*) is a screenshot from the modelling tool. Colours are not directly comparable, but the sketch shows that a channelised system in South changes into a shoreline system towards North and gets progressively deeper. This is replicated in the digital model (Image courtesy of Paul J. Valle)

history etc. (see Chaps. 4 and 11). Hence it is crucial to understand how sediments may change properties during burial and uplift in order to make a good assessment of the petrophysical data that are applied in the static and dynamic models.

22.3 Constructing the Static Reservoir Model

Essentially, the static reservoir model is constructed in two steps. First a structural model expressed as a 3D modelling grid is generated, and then this grid is filled with rock properties. An overview on this process is outlined in Fig. 22.6. The main elements in the model construction are:

- Model the seismic horizons and faults. Seismic interpretation provides the most important input for building the gross skeleton of the reservoir, and make the *seismic framework*.
- As seismic resolution is limited, additional zones may be included from well log zonation and correlation, and the conceptual model. This refinement will outline the *geological framework*.
- Based on the geological framework, one or more 3D reservoir grids are constructed. In many cases a high resolution *geological grid* (also called *static grid*) is made, where the actual property modelling takes place, while a coarser *flow simulation grid* is constructed for the purpose of dynamic modelling, see Sect. 22.4.
- *Property modelling* is the step where each cell is assigned various petrophysical values (such as porosity, permeabilities and fluid saturations) and other values (such as facies and region identifiers).
- If both a high resolution static grid and a coarser flow simulation grid are generated, the process of transferring properties to the coarser grid is known as reservoir property *upscaling*.

In the next sections, these steps will be explained in more detail.

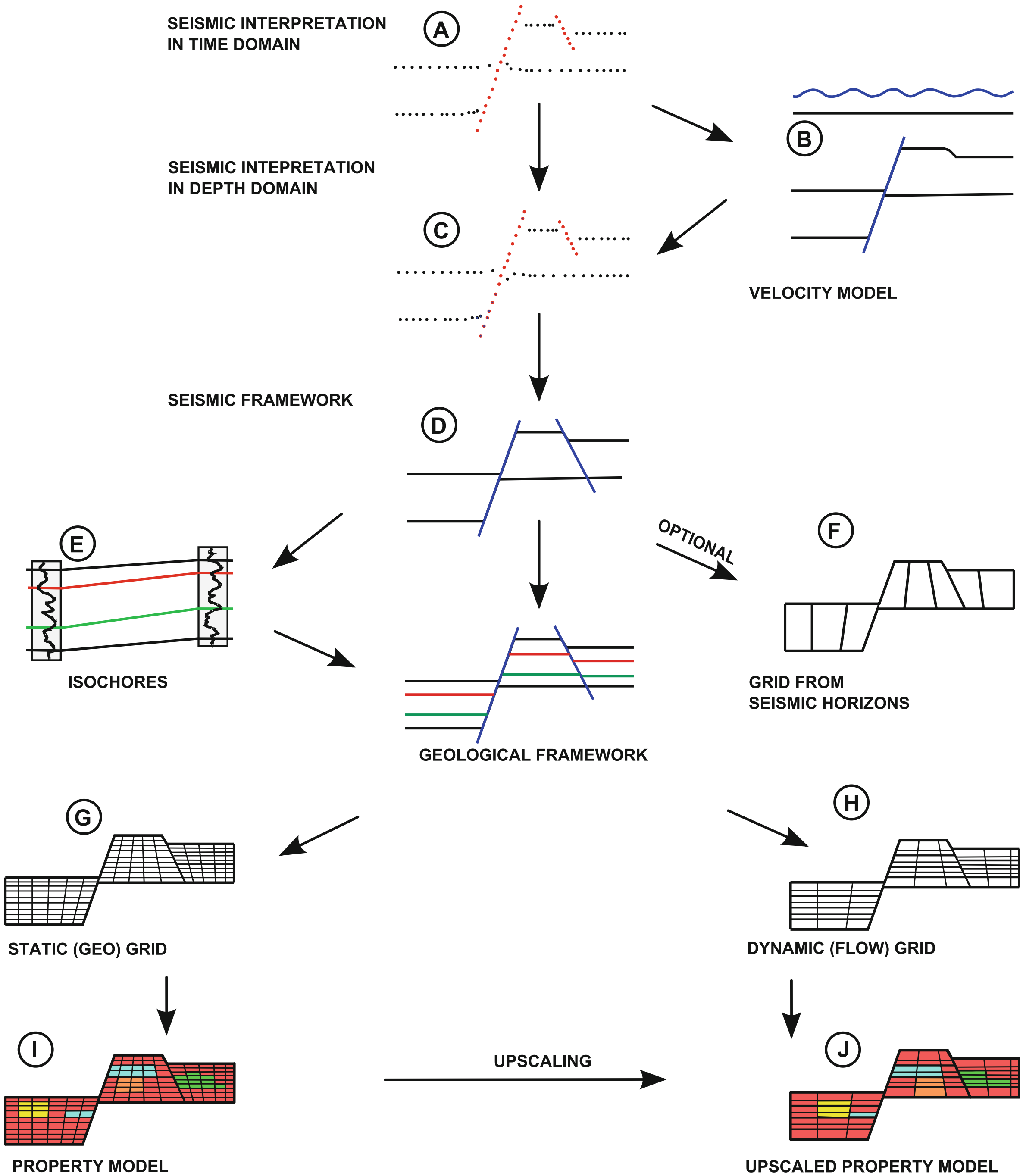

Fig. 22.6 Overview of a typical model construction work flow. Seismic interpretation is usually done in time domain and depth-converted (steps **a**–**d**). Isochore maps are made and merged with the seismic framework to make the geological framework (step **e**). An optional test grid may be made for quality control (step **f**). Based on this, two more 3D grids are made (steps **g**, **h**), which are filled with properties (steps **i**, **j**)

22.3.1 Seismic and Geological Framework

The seismic framework typically defines the top and base reservoir and in some cases internal reflectors (Fig. 22.6, steps a–d). Faults are interpreted from discontinuities in the seismic reflectors. As the seismic interpretation usually is done in the Two-Way Time (TWT) domain, a depth conversion will be needed. As the seismic resolution usually is limited to a few horizons in the reservoir, additional zones are commonly added based on well correlation (supported by the conceptual model). This provides the basis for creating isochore (thickness) maps, which are merged into the seismic framework (including faults) by the modelling software. The resulting mix of interpreted seismic surfaces, faults and calculated intermediate horizons from well correlation and isochores makes the geological framework, which can be considered as the most precise model of the structural elements (Fig. 22.6, steps e–h). Note that different modelling software has different approaches to the details of this work flow, and some software incorporates parts of zonal modelling directly in the 3D gridding process.

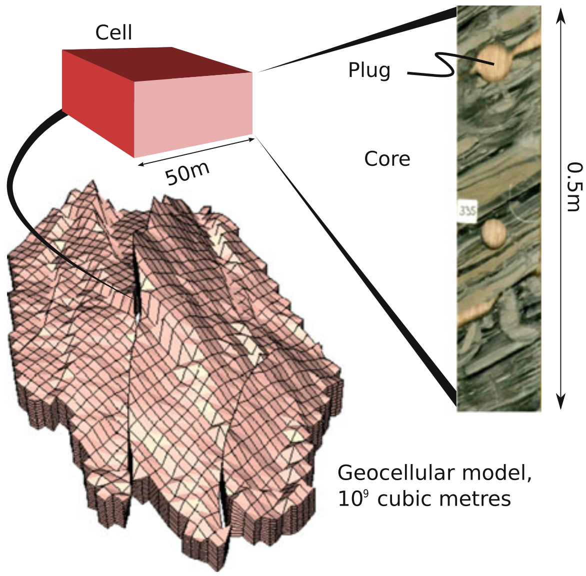

Fig. 22.7 While the geocellular model may contain millions of cells, it is still a major simplification as each cell can only hold one set of parameters. Hence variability seen in cores and outcrops will be averaged

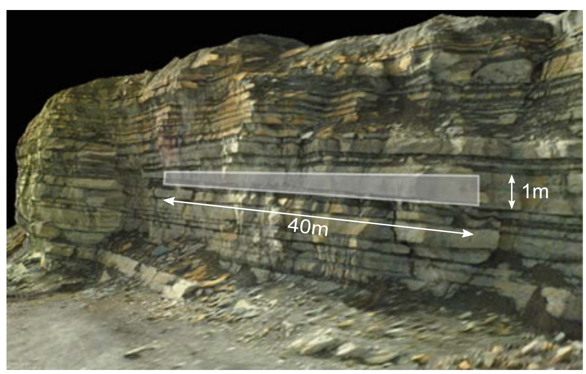

Fig. 22.8 The size of a typical static grid cell superimposed on an outcrop in Ainsa, Spain (image courtesy of John Thurmond)

22.3.2 3D Gridding for Static Modelling

The geological framework (comprising interpreted and calculated horizons) is usually surface oriented, i.e. it is made by a number of maps which make up a skeleton in three dimensions. However, properties may have values in any position between the surfaces. In order to populate the digital model with properties, we introduce an additional data type: the 3D grid. The 3D grid consists of numerous cells to build the reservoir volume, analogue to a "flexible" Lego brick model, and we often refer to this a *geocellular model*. What is important to understand in the property modelling is that each grid cell in the model is assigned one value for each reservoir property to be modelled. The typical size for a grid cell is from 20 m to a few hundred metres lateral resolution (X and Y direction of grid) and 0.5 m to up to 10's of metres vertical resolution (Z direction of grid); hence petrophysical values are averaged over a much larger volume than primary input such as core plugs and wells logs will represent (Figs. 22.7 and 22.8; see also discussion in Sect. 22.4.2).

The number of grid cells in a model (hence the average grid cell size) is often a trade-off between the need for the necessary resolution to be able to represent geological information adequately and computational storage and execution time. Large grids (i.e. many grid cells) will be progressively more time consuming to work with, both from a

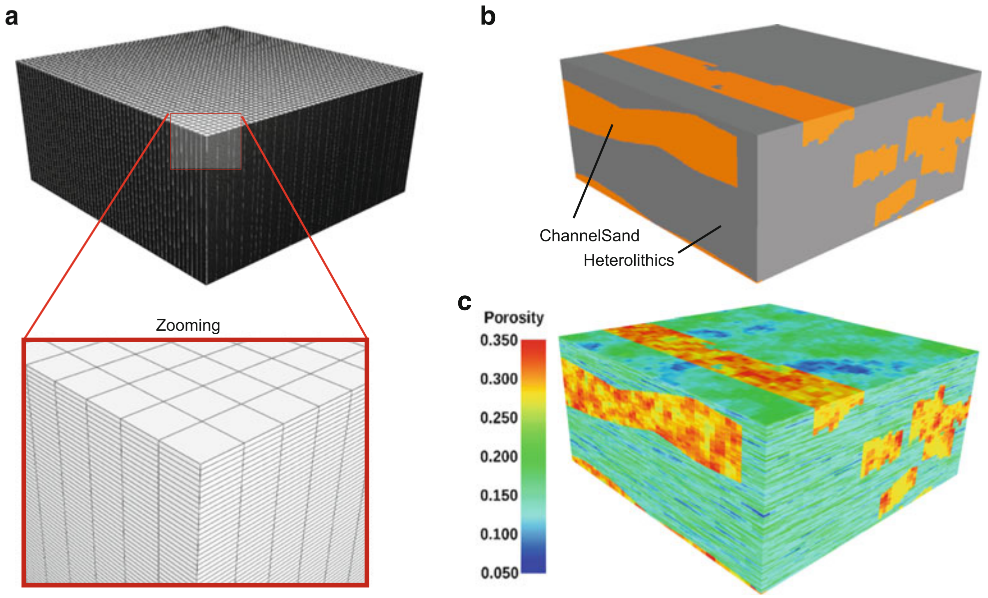

Fig. 22.9 Going from grid (**a**) to discrete facies model (**b**) and further to a continuous property model (here porosity) (**c**)

geomodelling perspective but especially from a dynamic simulation point of view. The maximum number of grid cells in a model is limited by prevailing computer power, but as an estimate static models can handle up to 100 million cells which is typically two orders of magnitude more than dynamic models can deal with. There are a few important requirements concerning the geological modelling grid:

- The grid should be as uniform as possible, hence the grid cell size should not vary too much in the model, for each zone. The underlying methods for property modelling commonly assume a uniform grid, and the result may be distorted if the grid is non-uniform.
- The grid orientation both vertically and laterally should follow main directions of the heterogeneities.

It is important to have a good multidisciplinary co-operation when designing the geological modelling grid, taking into account not only the input parameters but also the modelling objectives and practical use of the grid. A simple grid (i.e. coarser grid resolution and fewer grid cells) designed for a crude in-place volume estimates will have quite different requirements relative to a grid constructed for a static model that shall serve as basis for a dynamic simulation model for the calculation of production profiles and reservoir management.

22.3.3 Property Modelling

When the grid construction is finished, the next step is to fill in the cells with properties. The most important properties are the petrophysical ones (porosity, permeabilities, saturations), but the grid may contain a large number of properties. We can classify the properties into two main categories:

Discrete or Categorical Properties These properties hold a single integer value per cell. This cell value is commonly just an alias or indicator for a given feature, such as a facies name. For example, cells with integer value 1 may be associated with facies "channel-sand", while cells with value 2 may be associated with facies "deltaplain-mudstone", etc. The use of numbers and associated facies names will vary from case to case. Other examples of discrete variables are region and fault block identifiers.

Continuous Properties These values represent a scalar representation of a petrophysical property directly, such as porosity (which is usually given in a fractional form, such as 0.25). The properties are not restricted to traditional petrophysical properties; e.g. they may include other physical properties such as geophysical data (acoustic impedance, P wave velocity, etc.).

In order to achieve realistic results using a property model, a mix of categorical and continuous properties are used. Best known is the "two-stage" approach applied for petrophysical properties. First, the main flow units are modelled using a categorical property; so-called *facies modelling* (Sect. 22.3.3.4). Next, each facies is populated independently with continuous petrophysical properties (Sect. 22.3.3.5). The principles of going from a facies model to continuous properties are illustrated in Fig. 22.9.

The next question is how shall the property model be populated in practice? What input data are available? Generally speaking, we have the following data available:

- Well data, in the form of a zone log, facies log, porosity, saturation and permeability logs. These are usually treated as hard data, meaning that well observations should be conditioned properly in a model.
- Seismic data, in the form of depth-converted interpretations and attribute cubes. These data have usually poorer resolution than the cells we model. Seismic data are regarded as less certain than well data, and the use of seismic data will vary a lot from field to field, depending on seismic resolution and availability. In general, seismic data should be treated as semi-quantitative.
- The conceptual model (see Sect. 22.2.3) may be regarded as "soft" data, meaning that is cannot be conditioned directly; rather the model is "tuned" to acknowledge the main features in the concept description.

22.3.3.1 The Role of Geostatistics

Before we proceed into actual property modelling methods, it is important to emphasise the role of *geostatistics* in reservoir modelling. Both the analysis and modelling of facies and petrophysical properties are heavily driven by geostatistical principles and methods, and the use of geostatistical methods is also increasing within structural framework modelling. The field of statistics in general is concerned with quantitative methods for collecting, summarising and analysing data, as well as drawing conclusions and making reasonable decisions on the basis of such analysis, and is an extensive science. Geostatistics is distinct from statistics in three main aspects: (1) focus on the geological origin of the data, (2) explicit modelling and treatment of spatial correlation between data, and (3) treatment of data at different volume scales and levels of precision (Deutsch 2002).

The geomodeller will need a certain level of skills within geostatistics as the modelling software draws heavily upon the geo-statistical methods and terminology. A sufficient skill level is usually a good understanding of geostatistical principles and terms; the detailed mathematics behind it is usually not required. However, it is common that oil companies employ a number of statistical experts who are available as support when doing reservoir modelling in general, and in particular the uncertainty analysis associated with it (Sect. 22.5).

22.3.3.2 Blocking of Well Data

Before starting the actual property modelling, the available well data need to be sampled into the scale of the geological modelling grid. This process is most commonly referred to as *blocking* of wells/well data but could also be called *upscaling* of well data. This involve sampling and averaging of petrophysical log data into the scale of the geological grid.

Blocking of well data is not a trivial task. The well logs (see Chap. 16) are a result of an averaging due to the logging tools, particular measurement technique, and the sampling increment is usually approximately 15 cm for conventional logs. The actual resolution is usually less, typically from 30 cm to several metres, depending on the tool and measurement conditions. This means that small-scale laminae (from mm scale to tens of cm scale) commonly seen in cores are not captured by the logs, and shoulder bed effects (the smearing or averaging when going from one lithology to another) can be significant. When these logs are blocked, a further averaging is done. Horizontal wells have additional challenges. An example of well blocking is shown in Fig. 22.10. Loss of detail from the original logs may be compensated by using a finer grid; however using too many grid cells will be a disadvantage as it will increase the needed computation power later in the modelling process.

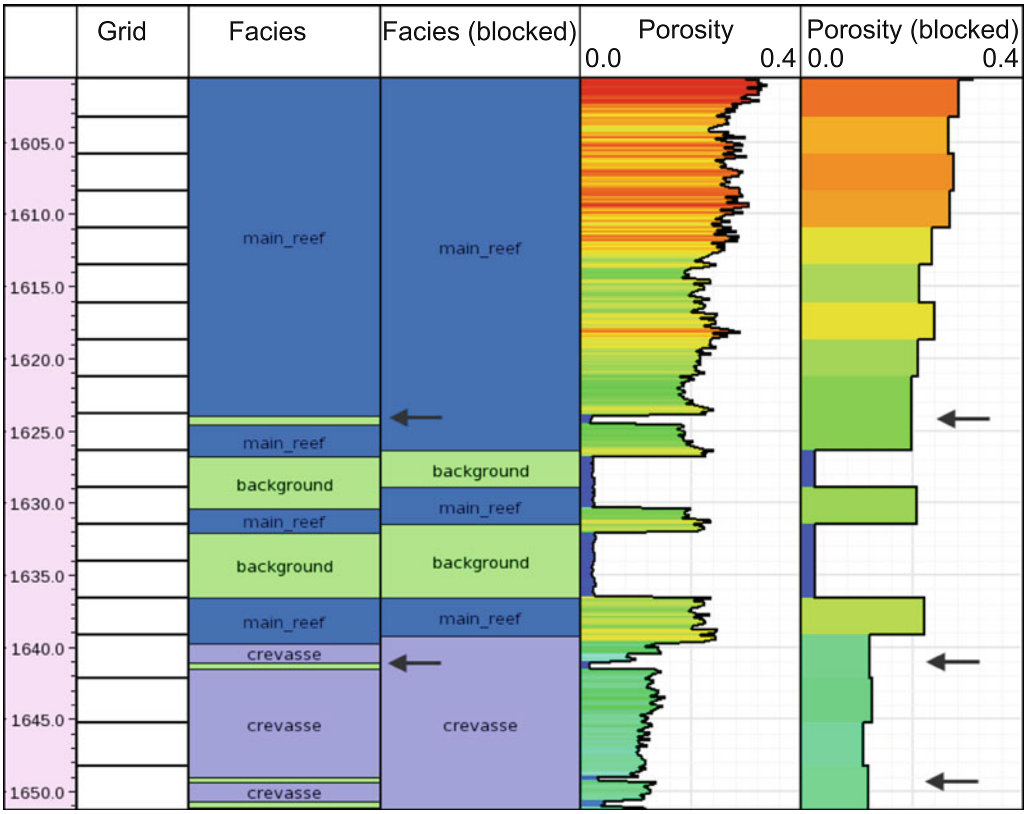

Fig. 22.10 Blocking well data. This example shows blocking (upscaling) of a facies log and a porosity (ϕ) log. For the facies log, the dominant facies will be used (majority rule). For the porosity log, an arithmetic average will be applied. In both cases there will be some loss of details (*arrows*), and the geomodeller will have to decide if that is acceptable for the purpose of the model

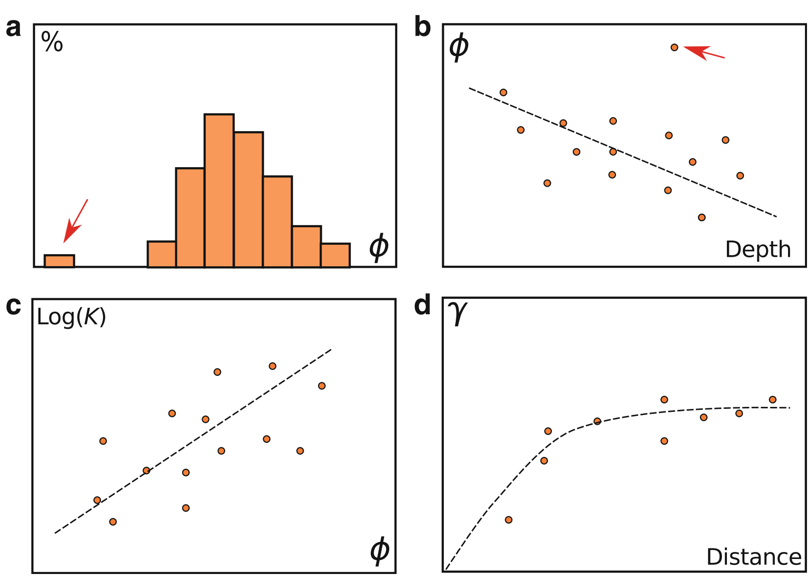

Fig. 22.11 Principles in data analysis. In (**a**), a histogram gives the data range for porosity. Outlier data (*red arrow*) must be identified and removed if they are evaluated as erroneous data. In (**b**) the porosity is crossplotted with depth to reveal depth trends. In (**c**), the porosity vs. permeability correlation is plotted, while in (**d**), the spatial correlation (variogram) is displayed

22.3.3.3 Data Analysis

The next important step in property modelling is data analysis. The blocked well data (and other data if relevant) are analysed using geostatistical techniques in order to be able to set up the modelling process optimally. The analysis includes:

- Histogram plotting, which shows the data distribution of a given property (Fig. 22.11a).
- Scatter plots of the properties versus spatial dimensions. This will show if the property has trends that are important to acknowledge in the modelling. One trend typically found is a porosity decrease with depth (Fig. 22.11b).
- Crossplotting of various properties (multivariate analysis). Commonly, a correlation between porosity and the logarithm of permeability is found (Fig. 22.11c).
- Spatial correlations are found by variogram analysis. This is a common technique in geostatistics, analysing how the property will vary in a spatial context (Fig. 22.11d).

The data analysis provides the fundamental input to both facies modelling methods and modelling of continuous properties.

22.3.3.4 Facies Modelling

The word "facies" has several different definitions in geology; for reservoir modelling, a facies is an architectural element that has a certain geometry and a properly defined distribution of its internal continuous properties. As an example, a fluvial reservoir zone may comprise channel facies with high porosities and a quite specific elongated shape, while the overbank facies has poor reservoir properties with no particular shape (only filling the space between channel bodies). The boundary between each facies may be quite sharp, see example in Fig. 22.9. It is important to understand that *facies modelling is an optional step;* is not required in order to get a model that can be used for volumetrics and flow. However, a facies model has the advantage of introducing geologically reasonable shapes into the geomodel, thus honouring the conceptual geological understanding. Most reservoir models utilise facies modelling in some sense in order to improve the petrophysical architecture, although complex facies models are demanding to construct. The important choice of whether to do facies modelling or not should be based on the modelling objectives, the conceptual model, the need for accuracy and the available time and resources.

Whether facies is modelled in a simple fashion (e.g. just two or three facies) or more complex facies patterns depends on the conceptual model and model purpose. Models that should be input to dynamic simulation usually require facies models as the facies dictates flow units and heterogeneity which can have significant impact on fluid movements in the subsurface.

From a model technical view there are several available techniques for making a facies model. The main techniques, with a short description of pros and cons, are briefly mentioned here:

Pixel-Based Facies Modelling In contrast to object-based methods, the pixel-based methods use the 3D grid directly in the modelling. A number of different pixel based methods are available.

- Truncated Gaussian fields (Deutsch 2002, Chap. 6). This methodology is useful for modelling large scale facies objects that appear in a specific order, like the boundaries between the lower, middle and upper part of a shoreface, or the boundary between shoreface and delta plain (Fig. 22.12a). Truncated Gaussian fields are usually unsuitable for flow units which have distinct shapes.
- Sequential indicator simulations (Deutsch 2002, Chap. 6). This methodology can output a large number of random patterns and has the advantage of quite fast modelling when conditioning to a large number of wells. However, the output from indicator methods may have difficulties in matching the conceptual geological model.
- Multi-point statistics (Deutsch 2002, Chap. 11). This technique utilises training images, providing an intuitive way for the geologist to describe the geology. This methodology has the advantage of quite fast modelling when conditioning to a large number of wells, and may in some cases replace the need for using object-based methods.

Object-Based Facies Modelling This is a class of facies modelling techniques that utilises a statistical marked-point process to create facies objects based on geometrical input (Deutsch 2002, Chap. 7). Object

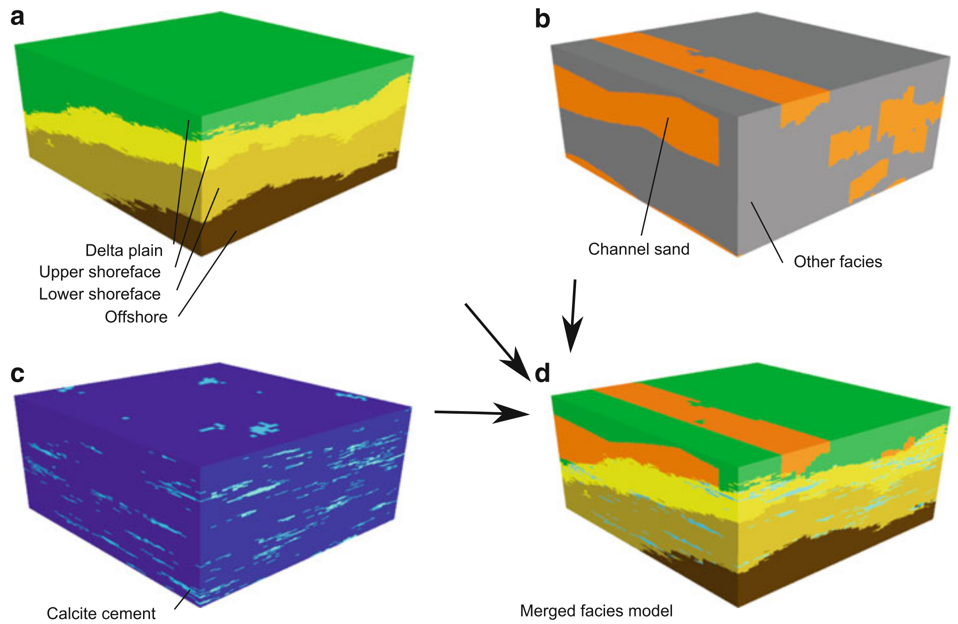

Fig. 22.12 Facies modelling often involves combining several techniques. In (**a**), a truncated Gaussian method is applied, while different object models are applied in (**b**) and (**c**). These are merged by simple grid operations into a resulting facies realisation, in (**d**)

based methods place the various facies bodies into a background facies, according to statistical rules and geometrical relationships. Object modelling is intuitive in the way that input is provided by the modeller on the shape and size of the objects to be modelled, but may be complex to parameterise and to condition (fit) with all observations, such as blocked wells and seismic data. Sometimes the methods are slow to run (taking hours on high-end computers). The most typical example of object modelling is fluvial channel deposits which are modelled as elongate sinuous objects within a "background" of the delta plain deposits (Fig. 22.12b).

Depending on the modelling tool, most or all of the techniques can be conditioned to (fit to) several data types. Most vital are well data, as well observations are "hard" data that should fit naturally in the model after facies modelling is done. In addition, most tools can use seismic conditioning, which will guide the modelling algorithm to generate a pattern or feature (such as "sand-probability") extracted from the seismic data.

To improve the result from facies modelling, several different techniques can be applied within one unit and finally merged in order to achieve a realistic result. An example of a merged facies model is shown in Fig. 22.12d.

22.3.3.5 Petrophysical Property Modelling

Petrophysical property modelling is the process of distributing reservoir properties into the geological grid. This is performed individually for each reservoir zone of the geological grid. If facies have been modelled the properties are distributed individually for each modelled facies for each reservoir zone.

A very common approach for petrophysical property modelling in all modern modelling software is the use of geostatistical Gaussian methods (Deutsch 2002, Chap. 8). This implies that the properties that will be modelled have a distribution that is close to a Gaussian (Normal) distribution, or a distribution that can be easily transformed to a Gaussian shape. To achieve the Gaussian distribution, a transformation sequence is needed, and establishing that sequence is an important part of the data analysis.

The Gaussian modelling has two output modes:

1. Prediction mode or *kriging* mode gives the expected average outcome. This is illustrated in Fig. 22.13a. Observations (wells) will stand out as bull's eyes, and outside the influence range (which

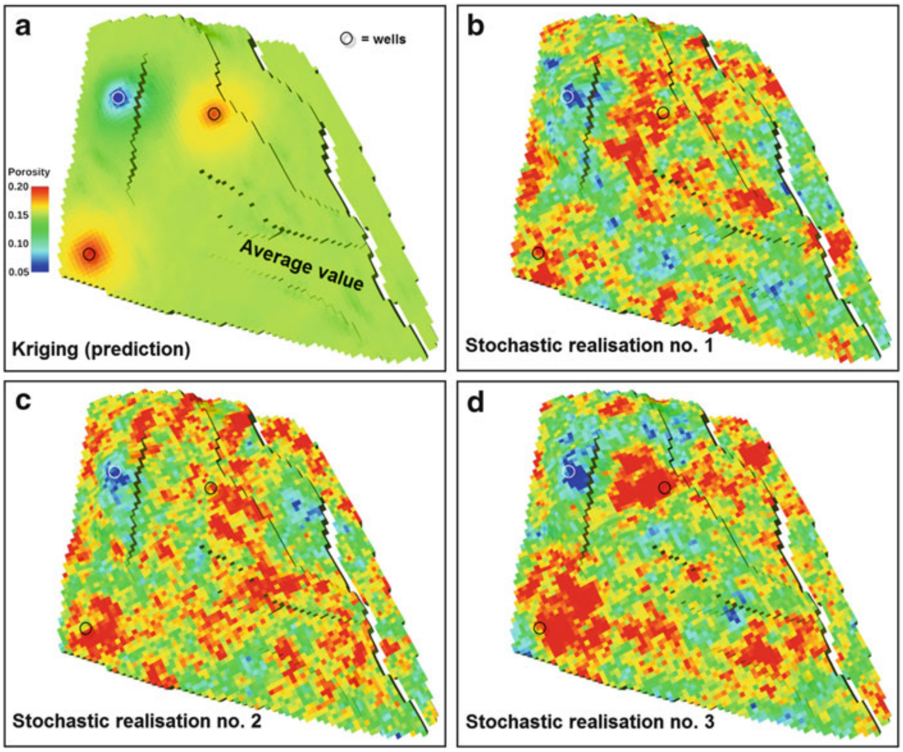

Fig. 22.13 Petrophysical modelling based on Gaussian methods. (**a**) Shows kriging mode, while three realisations from stochastic mode are shown in (**b**), (**c**) and (**d**)

is given by the variogram, cf. Fig. 22.11d), the model values will tend towards the average. There will only be one single outcome "realisation" in kriging mode. An important weakness with kriging is that the result becomes too smooth, and therefore unsuitable for realistic flow modelling.

2. A *Gaussian simulation* (stochastic mode) will add variability between well observations (Fig. 22.13b–d). Due to the sparseness of data (wells), the modelling software will use random generators in combination with the geostatistical model to populate the cells. The result will appear more realistic and reproduce the variability seen in scatter plots and histograms from the data analysis (Fig. 22.11), and Gaussian simulations are usually preferred for flow models.

The input settings (such as the specification of variogram models) for kriging or Gaussian simulation are generally the same, and it is worth noting that the average of an infinite number of stochastic Gaussian realisations would generate the same result as the kriging model.

An example of a model from a North Sea field is given in Fig. 22.14. Here stochastic facies are filled with Gaussian simulation of porosity.

22.3.4 Volumetrics and Model Ranking

Most of the available modern geomodelling tools offer predefined panels for volumetric calculations. They are all based on the same classic equations for volume calculations of oil in place (V_p)

$$V_p = V_r \cdot N/G \cdot \varphi \cdot O_{sat}$$

(see Sect. 21.2) When standardising to surface pressure and temperature, a shrinkage factor (B_o) is also needed. A similar equation is applied for gas in place volumes.

In simple cases, no facies are modelled, and properties are modelled with kriging or other interpolation techniques. In such cases volume calculations are straightforward. However, today most major oil

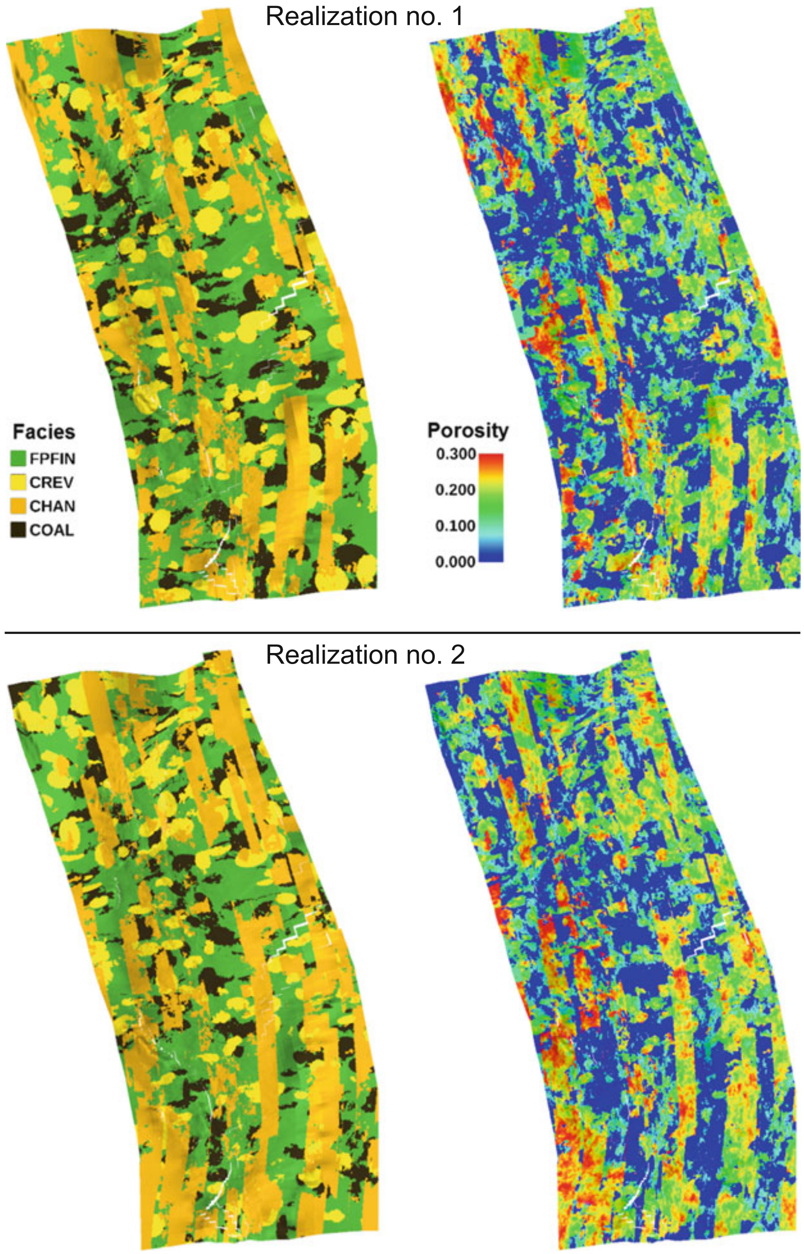

Fig. 22.14 Example from an offshore Norwegian field model, with facies realisations (*left*) which are input to porosity realisations (*right*). Both the facies and the petrophysical modelling within each facies are based on stochastic methods

companies are utilising stochastic techniques for facies and petrophysical property modelling, as these produce more realistic variability. This means that the modelled distribution of properties and resulting volumetrics represent one possible outcome within a larger outcome space. Hence it will be necessary to run multiple realisations of the geomodel, to be able to visualise the outcome space and to run volumetric calculations on all of these model realisations.

Often tens to several hundreds of stochastic model realisations are generated. For computer capacity reasons, it is rare that all realisations are taken further to flow simulation models, hence a *ranking of realisations* is required. Picking representative model realisations may be challenging. One possible approach may be to choose the realisations that are volumetrically closest to the average off all the model realisations. However, it will also be important to make a visual inspection to ensure that the most representative model realisations are chosen, and it may also be necessary to investigate those realisations that represent end-members in some sense, such as volumetrics or connectivity. In a complex situation with a large number of model realisations, so-called streamline simulations (which are fast and simplified flow simulations) may be used as a guide for picking an appropriate set of model realisations.

The fact that many reservoir models today are based on stochastic modelling techniques must be carefully considered when using models for well planning or other decisions. For example, a horizontal well optimised for penetrating highly permeable layers in one model realisation, might be positioned in low permeability layers in a different stochastic realisation of the same model, due to the stochastic distribution of facies and petrophysical properties. Hence, it is of critical importance to consider multiple realisations when doing such analysis.

22.4 Constructing the Dynamic Reservoir Model

While geological (static) models are the domain of geologists, geophysicists and petrophysicists, the dynamic models are in the hands of the reservoir engineers. Flow simulation is a major activity in oil companies, as such simulations can be a very valuable tool to understand the reservoir dynamics, optimise the production and compute recovery factors, Chap. 20 (Fig. 22.15). Flow simulations are quite computationally demanding, and require powerful "number-crunchers" that are occupied continuously, as each flow simulation run may take from several hours to many days.

Most dynamic models inherit both the structural and property model from the static model, and tight integration between the disciplines is required for an optimal result. In addition, the dynamic model needs to incorporate special data types only relevant for flow modelling, such as relative permeabilities and a number of temperature and pressure dependent fluid properties.

Dynamic models can also deal with cell-face properties. This means that the numerical properties are not limited to the cell-centre, but also add properties controlling the flow between two adjacent cells. This is quite often used to model the effect of thin barriers and baffles, both of stratigraphical origin and those created by faults.

22.4.1 3D Gridding for Flow Modelling

The grid used in flow simulation is usually coarser than those that are used for static models. To save computational time, flow simulation grids usually have coarser cells in parts of the reservoir which are of less interest, such as attached water bodies (aquifers) which may be important for reservoir energy, but do not require the detailed cells required for two- or three-phase flow near oil and gas producers. This is possible to achieve as the flow simulator can handle varying cell sizes, in contrast to property modelling methods which commonly require quite uniform grids. A comparison of such grids is shown in Fig. 22.16.

There are cases where the static and dynamic modelling is performed on the same grid, and this simplifies the modelling. In addition to the requirement for a relative uniform grid, this also demands an in-depth analysis of proper scales, so-called REV (Representative Elementary Volume) analysis, which is discussed in Sect. 22.4.2.

22.4.2 Upscaling from Static to Dynamic Models

As previously stated, there are several ways of defining the scale relationship between the geomodel and the dynamic simulation model. In most cases, the geomodel is constructed at a finer scale (for accuracy), and a property upscaling step is necessary in order to have a simulation model with a number of grid cells giving reasonable computational time for the dynamic simulations. We will not go into the details of various approaches and techniques for upscaling the parameters of the geological model from geogrid scale to simulation grid scale, however a few main principles can be outlined:

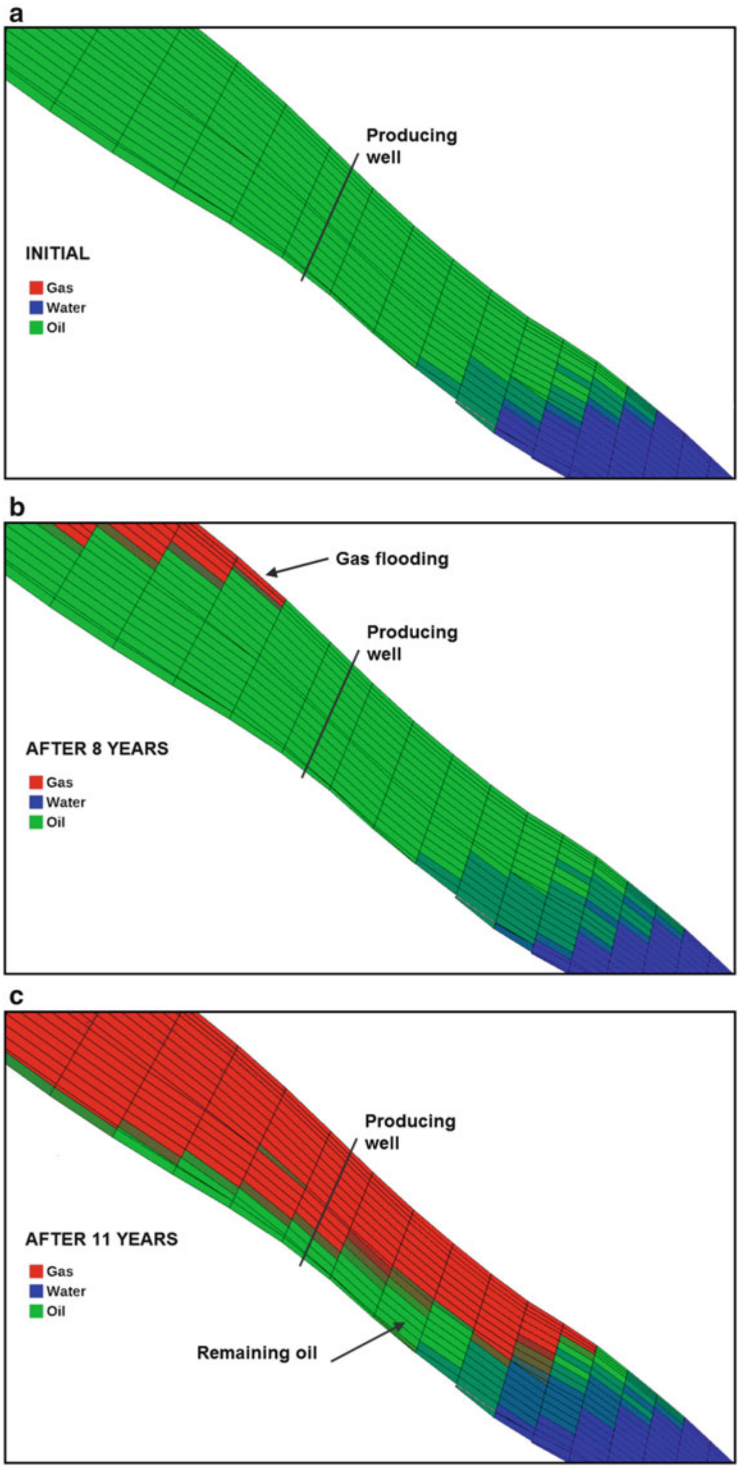

Fig. 22.15 Example from a flow model, taken from a major North Sea field. In (**a**), the reservoir is filled with oil (*green colour*). During production, gas from gas cap (*red*) will expand and replace the oil, moving towards the well (**b**). In final stage (**c**) the well will produce primarily gas, while the model reveals remaining oil in the lowermost intervals, which would eventually require a new dedicated well to be produced

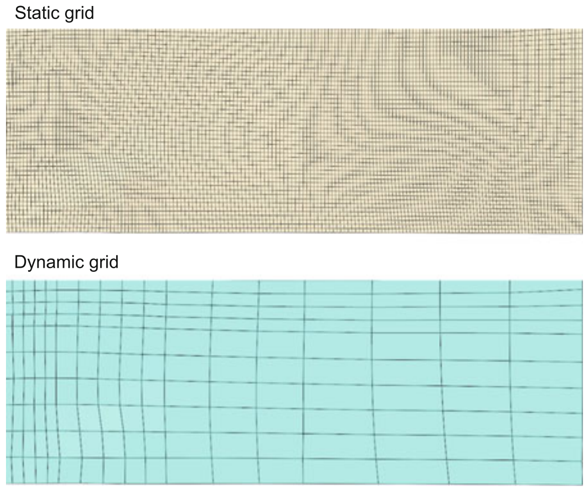

Fig. 22.16 Grids for flow models have other requirements than grids for static property modelling. In this case, the dynamic grid has varying cell sizes that are fully acceptable in flow simulators, while the static grid shows a uniform grid that is required by most modelling algorithms

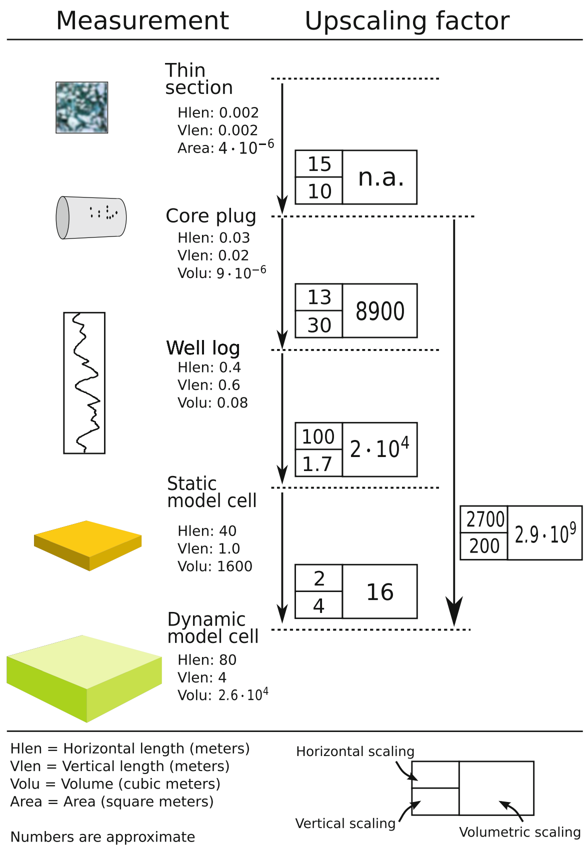

Fig. 22.17 An overview of typical measurements and/or data types, and the relative upscaling factors

- A proper handling of scales from one data-type to another is one of the most challenging tasks within reservoir modelling.
- The upscaling from a static model to a dynamic model has historically received much attention, but the actual scale change is relatively small compared to other upscaling operations we do (Fig. 22.17). For instance, the upscaling of core plug data to well log resolution is a much larger leap, but is quite often ignored or treated simplistically.
- Quite often, core analysis data for relative permeabilities and capillary pressures are applied directly in the dynamic model, which implies a 10^9 upscaling factor! (Fig. 22.17)
- While porosity and saturations are trivial to upscale, the permeability tensor is much more challenging. Even more difficult are the saturation dependent functions, such as relative permeabilities and capillary pressures.
- Applying measurements from one scale at another scale is not necessarily wrong; if the reservoir interval or facies is homogenous, or the spatial scale of variation is relative large, then core plug samples may be sufficiently valid for large grid cells.
- The goal with every upscaling exercise is to represent the small-scale data using an *appropriate average;* it is the method to achieve the appropriate average that can be difficult to find, in particular for permeabilities.

For simple scalar properties such as VSH (volume of shale), porosity and saturations, the upscaling methods are straightforward, based on weighted arithmetic averages. For categorical properties (such as facies) the so-called majority rule is applied, e.g. the dominating facies will "win" (an average of facies has no physical meaning). For upscaling of permeability and saturation functions, a large number of methods exist, and choosing the optimal approach is case dependent and hence challenging. A review of different upscaling methods is provided by Christie (1996).

A serious weakness with the standard work flow is that many upscaling steps are neglected, or carried out inappropriately. One common error is to apply core-plug values (permeability, porosity, etc) directly at larger scales (Fig. 22.17). In addition, only the sampling size is considered, but the scale of heterogeneity within the rocks is actually unrelated to sampling.

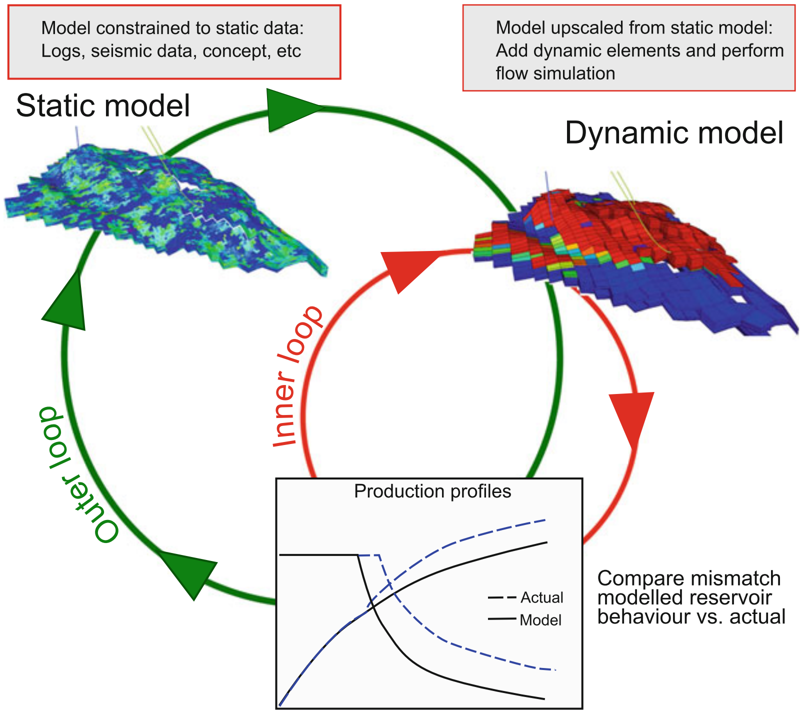

Fig. 22.18 History matching loop. Modelled dynamic behaviour is compared with actual, and calibration of the model may be done in the dynamic model directly (*inner loop*) or the static model (*outer loop*)

These issues are addressed in alternative upscaling philosophy called *geologically based upscaling*, which is based on separation of scales seen in the sedimentological patterns. One goal here is to investigate if the static geogrid and the dynamic simulation grid can be constructed at the same scale. The property modelling will be based on a hierarchical procedure, where the scales of the different heterogeneity levels are identified. To identify the REV levels is essential here as they define the smallest volume where the measurements yield a proper representation of the whole volume. The approach is used to provide a systematic upscaling work flow from the finest scale (pore level) to flow simulation grid level. For further reading, see e.g. Liu et al. (2002), Pickup et al. (2005) and Scaglioni et al. (2006).

If the project has enough time available, the ultimate check of the dynamic impact of upscaling is to run simulations on the geogrid scale. Running a dynamic simulation on a fine-scaled geomodel might take weeks, however this can represent a very good consistency check.

22.4.3 History Matching

History matching is an important work process within reservoir modelling, and has long been a major part of conducting reservoir simulation studies for the purpose of effectively managing reservoirs. It is defined as the adjustment of reservoir model input parameters so the model's predictions match historical production data. This adjusting is necessary as long as the static model (which provides input to the dynamic model) is not capable of conditioning on production behaviour.

History-matched models are used to test development or depletion plans, and thus provide the basis for business decisions about how the reservoir will be produced. The question is how should the model be adjusted? There are two end-members of doing history matching (Fig. 22.18):

1. The inner loop. After the model has been upscaled from the static model, the reservoir engineer adjusts the flow simulation model in order to match model with production data. For example, the reservoir engineer may suggest that the permeability should

be multiplied with a factor ten in selected areas to improve match.

2. The outer loop. In this case the reservoir engineer works together with the geomodeller to modify the static model that provides input to the dynamic model.

There is no doubt that the "inner-loop" is most frequently applied as it is simpler and results will be quicker. However, it breaks the link with the static model, and the models can diverge significantly. In many cases, the reservoir engineer can achieve a sufficient history match with values that cannot be defended from the static model and concept model. Because the goal of history matching is to develop a model or models that can be used to make reliable predictions of future performance, it is important to ensure that history match changes are consistent with the geologic concept that has been inferred from available geologic data. If the history match changes are not consistent with geologic data, it is less likely that the predictions of the resulting model will be reliable. That is, if history match changes are not consistent with a geologic concept, it will be difficult to extrapolate to other parts of the reservoir, or in some cases, even to later times (Lun et al. 2012).

Hence, working along the outer loop will more or less ensure that the model is updated according to the concept model and in doing so will promote cross-disciplinary consistency. However, as the outer loop is more demanding and time consuming, a hybrid solution is also attractive. This implies that the reservoir engineer tests alterations to model parameters in the inner-loop, but at frequent intervals includes the outer-loop in order to calibrate the static model and ensure that changes made are within acceptable ranges.

22.5 Uncertainty Handling

A key aspect of reservoir modelling is the handling of uncertainty. With limitations in seismic resolution, number of available wells etc., there will always be a significant uncertainty associated with the description and understanding of the subsurface. The impact of this uncertainty can to a certain degree be estimated through constructing alternative scenarios and statistical realisations of the model. The aim of this is to quantify the impact on static and dynamic volumes, impact on depletion planning and well placement.

Our insight of the reservoir evolves through the life of a field. As the field moves from the initial exploration phase, via the field development phase, through the early production phase and eventually ends up in the late stage IOR (Improved Oil Recovery) phase, the amount of available static and dynamic reservoir information increases. Hence the development of reservoir understanding and modelling is a dynamic and continuous process. Uncertainty is a complex term, and can be classified as follows:

Uncertainty Due to Lack of Data Although we assume we know the geostatistical model, we lack data in the reservoir. For instance, at some co-ordinate between wells, we cannot predict if we have facies A or facies B, as both can be possible. This is illustrated in Fig. 22.14, where the stochastic method predicts a different facies and porosity at a single position in the reservoir.

Uncertainty Due to Lack of Knowledge This relates more to the "human factor" of uncertainty. As the data analysis is not definite, we may end up with many alternatives (scenarios) regarding how to set up the model. For instance, in a fluvial reservoir, we may have one case with narrow channels with a North-South direction, while another scenario could be to have broader channels trending East-West. We usually treat this by scenario modelling, i.e. building alternative models.

Uncertainty Due to Imprecise Measurements All the measurements we perform have some uncertainty, and it is important to take this into account. For instance, the density and resistivity logs are uncertain due to uncertainties in well logging, and those uncertainties propagate in the estimation of the derived petrophysical properties such as porosity and saturations.

Uncertainty Due to Unknown Unknowns These are the uncertainties we do not test for – we simply do not know their existence. One example could be that none of the concept models we test are the right one. Another example is that the software performs erroneous calculations we are not aware of, or (usually more frequent) that the reservoir modeller makes mistakes that are not captured by the quality control.

Quantifying and communicating uncertainty from reservoir models is a big topic, and is one which is not covered in any detail here. It is important to understand and communicate to the decision makers (for example of a field development or an IOR initiative) that the deterministic outcomes of a modelling exercise (such as volumes, production profiles or well positions) are only one valid solution in an often large outcome space. If some of the input parameters are skewed (e.g. having a large probability of a fluid contact being deeper rather than shallower) this will affect the uncertainty analysis, and the statistical mean value may deviate significantly from the deterministic base case model.

22.6 Summary

The purpose of this chapter is to introduce some of the key elements and success factors for 3D reservoir modelling, which now is a major activity in most oil and gas companies. Proper planning with clearly stated business objectives is a good starting point for successful reservoir modelling. Constructing a high quality database of modelling input data can be time consuming, however it will ultimately save time for the project. The construction of reservoir models is an integrated and multidisciplinary process, involving static and dynamic data. Many disciplines provide input to the geomodel, and the geomodel is most often handed over to reservoir engineers for dynamic simulations. Keeping all project members actively involved and the ability to communicate clearly between all the involved disciplines is a key factor for achieving a good result. Through modelling alternative conceptual scenarios, and by making multiple stochastic realisations, the uncertainty related to estimated static and dynamic volumes can be quantified.

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