RESERVOIR ENGINEERING FOR GEOLOGISTS
Reservoir Simulation

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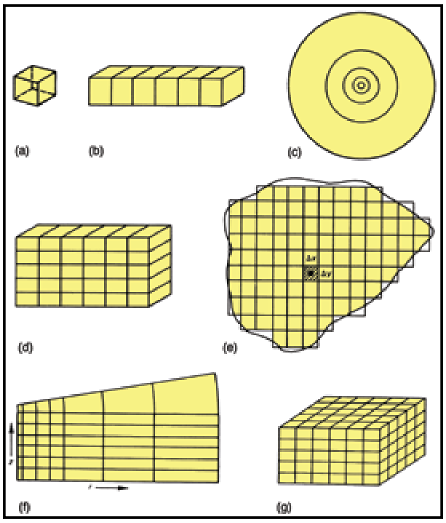

Figure 1. Typical Reservoir Simulation models (a) tank, (b) 1D, (C) 1D radial, (d) Cross-sectional, (e) areal, (f) radial cross-sectional, and (g) 3D. Mattax and Dalton (1990).

In Fekete's experience, a well performed reservoir simulation represents the ultimate integration of geology, geophysics, petrophysics, production data, and reservoir engineering. Through simulation, the flow of multiple fluids in heterogeneous rock over time can be quantitatively estimated to gain insights into reservoir performance not available by any other means.

Initially, reservoir simulation was reserved for large reservoirs requiring large capital investments that justified costly, intensive studies such as offshore developments. However, simulation of more modest-sized reservoirs has increased as simulation software and computer capability have become more readily available. Oilfields under primary production, waterflood, and EOR typically qualify for reservoir simulation but its usage is not uncommon for gas fields, unconventional reservoirs, or pools undergoing CO_2 injection.

In broad terms, the geologist / geophysicist / petrophysicist's role in reservoir simulation is to reliably approximate the (a) stratigraphy, (b) structure, and (c) geometry of the reservoir flow unit(s) and the initial fluid distributions throughout. The aim of the exercise is to quantify and manage the subsurface knowledge and uncertainties. In the practical sense, a good model is the one that is fit-for-purpose utilizing sound geological reasoning and at the same time supports reservoir dynamics (e.g., fluid flow, history matching).

Geological data is often characterized by sparseness, high uncertainty, and uneven distribution, thus various methods of stochastic simulation of discrete and continuous variables are usually employed. The final product will be a combination of:

- observation of real data (deterministic component),
- education, training, and experience (geology, geophysics, and petrophysics), and
- formalized guessing (geostatistics).

The first step is the geologist's conceptual depositional model which (s)he must be able to sketch and explain to the other members of the team. The conceptual model should be broadly compared and tested with each discipline's observations and data (e.g., core permeability versus well-test permeability, core porosity versus log-derived values) until the team has a consistent explanation of the reservoir's pre- through post-depositional history. Hydrocarbon reservoirs are too complex to develop a complete understanding "in one afternoon" so the process should be viewed as a series of ongoing discussions.

The next step is to define, test, and prioritize the uncertainties to be modeled and their impact on the overall dimensions of the model. For example, a gridblock height that is too large to reflect the layering in thin beds will introduce significant errors in the flow net-to-gross pay estimates as well as flow pathways. It is essential to agree upfront on the level of resolution and details to be captured in the model. The appropriate level of detail can be different for each reservoir and is also dependent on the purpose of the simulation, sometimes testing and iterations maybe necessary.

Next comes selecting the appropriate grid type (regular or faulted) to model the present day structure of the reservoir. Components to be modeled include the top of structure, faults, internal baffles to flow, and any areal variation in thickness and rock properties. The objective is to replicate the orientation, geometry, and effect of the structural imprint as it affects flow within the model. It is imperative to validate the fault-horizon network to ensure it is geologically feasible and to ascertain the absence of structural distortion and other problems.

Facies modeling is the next step in construction. Where available, the best practice is to integrate core data and outcrop analogues to constrain and refine log-derived facies type and property estimates. Understanding the facies distribution provides a tool for predicting reservoir quality away from the known datapoints. The geometry (length, width, thickness, and direction) of each facies body will affect the way heterogeneities in porosity and permeability are modeled. Attribute analysis (inversion/QI) and geobodies extracted

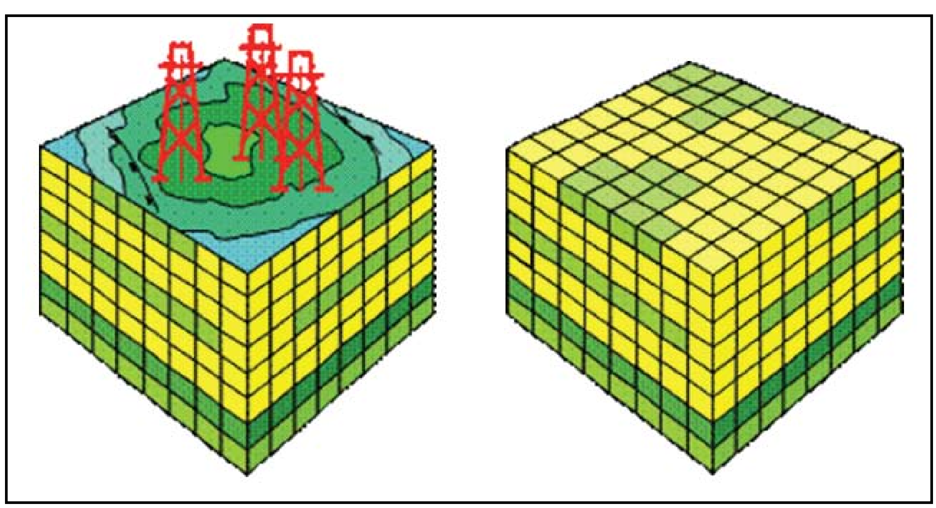

Figure 2. Example of 3D Gridblocks.

Symbol	Definition
Data To Describe Initial (Static) Condition	
Rock	
D	Formation top (structure)
h_t	Gross formation thickness
h_n	Net pay thickness
ϕ	Porosity at initial pressure
P_{cwo}* vs. S_w	Drainage (water/oil) capillary-pressure function
P_{cgo}* vs. S_g	Drainage (gas/oil) capillary-pressure function
Fluid	
B_o	Oil FVF
B_w	Water FVF
B_g	Gas FVF
ρ_o	Oil density at standard conditions
ρ_w	Water density at standard conditions
ρ_g	Gas density at standard conditions
Additional Data To Describe Gas/Oil Displacement (S_g Always Increasing)	
Rock	
k	Specific (absolute) permeability
k_{rg} and k_{ro} vs. S_o	Gas and oil relative-permeability functions (drainage)
c_f	Rock compressibility
Fluid	
R_s vs. p	Gas in solution vs. pressure
B_o vs. p	Oil FVF vs. pressure
B_g vs. p	Gas FVF vs. pressure
μ_o vs. p	Oil viscosity vs. pressure
μ_g vs. p	Gas viscosity vs. pressure
c_o	Oil compressibility
c_w	Water compressibility
Additional Data To Describe Water/Oil Displacement (S_w Always Increasing)	
Rock	
k_{rw} and k_{ro} vs. S_w	Oil and water relative-permeability functions (imbibition)
P_{cwo} vs. S_w	Imbibition (water/oil) capillary-pressure function
Fluid	
B_w vs. p	Water FVF vs. pressure
μ_w vs. p	Water viscosity vs. pressure
Additional Data To Describe Oil Invading a Gas Cap (S_w = Interstitial) or an Aquifer (S_g = 0)	
Rock	
k_{ro} and k_{rg} vs. S_o	Oil and gas relative-permeability functions (oil imbibition with hysteresis)
k_{ro} and k_{rw} vs. S_w	Water and oil relative-permeability functions (water drainage with hysteresis)
P_{cgo} vs. S_g	Imbibition (gas/oil) capillary-pressure function
Additional Data To Describe Three-Phase Flow	
Rock	
k_{ro}, k_{rg}, and k_{rw} vs. S_w	Three-phase relative-permeability functions**

*P_{cwo} and P_{cgo} need to be known at some definitive depth in the reservoir.

**These functions are seldom available by experimental measurement and are costly to obtain. Simultaneous flow of three phases usually occurs in only a small fraction of the reservoir, so Stone's two-phase approximation is ordinarily acceptable. Three-phase capillary-pressure relationships are usually calculated from two-phase gas/oil and water/oil relationships.

Figure 3. Rock and Fluid Properties. Mattax and Dalton (1990).

from seismic data are also useful to further refine the geological model.

It is important to quality check at each step of development to ensure consistency in the interpretation and reaffirm that the developing model is fit-for-purpose. A very detailed geological model may be unable to address the question(s) that the simulation team is attempting to answer.

The engineer's role in the process is to reliably simulate the performance of the geological model for the production scenario(s) under consideration by history matching a producing field and / or forecasting future performance. While it may seem that reservoir simulation would be straightforward if we only knew all the inputs, that perception is incorrect. Limited information unquestionably complicates the task but the most fundamental (and unavoidable) issue is the error introduced by approximating overwhelmingly complex physical geometries / interactions with simpler but manageable mathematical relationships.

Of necessity, simulation uses a sequence of three-dimensional gridblocks as a proxy for reservoir rock volume (see Figure 1). In order to keep the time, cost, and computing requirements of a simulation manageable, the total number of gridblocks is generally limited to less than 500,000, with a small simulation requiring less than 100,000 gridblocks. For either large or small projects, a gridblock may represent a "unit" rock volume of one or more acres in areal extent and several feet thick (Figure 2).

While fluid saturations and / or other properties can vary significantly over an acre and / or several feet of reservoir (e.g., an oil-water transition zone), each gridblock has only a single value for each property (e.g., porosity, saturation of water, oil and gas, permeability, capillary pressure) of the gridblock. When the true variation in the reservoir is too great to be comfortably represented by a single average value, the solution may be to (iteratively) increase the density of the gridblocks ("fine grid") in a specific area of the reservoir. Alternatively, a separate, smaller simulation may be run and the results provided as input to the larger study, as when modeling fluid and pressure behaviour at the wellbore sandface.

Similarly, simulation must approximate the continuous movement of fluids and the resulting changes in fluid saturations with calculations performed at discrete timesteps. Though it does not occur in the real world, there can be abrupt changes in a gridblock's fluid saturation(s) as fluids move into or out of the gridblock. The usual solution is to limit the magnitude of the change to tolerable levels through (iterative) selection of smaller timesteps.

The use of discrete timesteps and discrete gridblocks with a single value for each property also leads to the dilemma of what values to use in modeling the fluid properties for flow between adjacent gridblocks and adjacent timesteps. This artifact of numerical simulation also has consequences on calculated performance that do not exist in reality. For further discussion, see Chapter 2 of the SPE Monograph Volume 13. Though there is no completely satisfactory answer to the problem, workable approximations for flow across gridblock boundaries and

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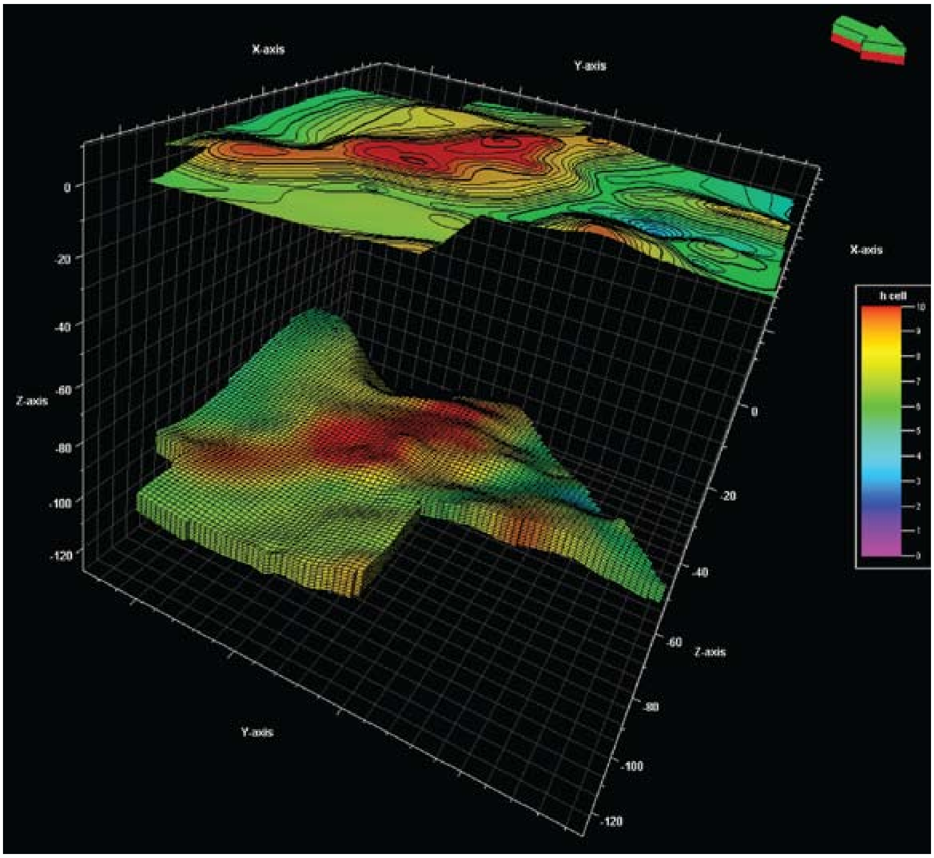

Figure 4. Visualization of 3D Model.

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between subsequent timesteps exist. The choice of which to use in a particular situation often comes down to experience and iteration.

DATA REQUIREMENTS

The rock and fluid properties required for reservoir simulation are summarized in Figure 3. Collecting the data and putting it into a form that can be imported in a reservoir simulator can be a major effort in itself.

ASSIGNMENT OF GRIDBLOCK PROPERTIES

Chapter 4 and 5 of SPE Monograph 13 provide further discussion on the challenges of assigning representative average values for rock and fluid properties to each gridblock in a simulation model and the size of gridblocks and timesteps to use. The choices are interrelated and influenced by:

- the areal and vertical variation in the observed rock and fluid properties,
- the type of physical processes being modeled, and
- the solution techniques being used.

Often, the best approach is to select the smallest gridblock size and number of layers needed to accurately describe the changes in reservoir facies, reservoir geometry, and fluid distribution. For example, fluid saturation changes in an oil-water transition zone might require gridblocks with an unusually small height of one foot or less to adequately represent the change in saturation through the transition zone with the series of single values available to "stacked" gridblocks. Production and injection wells and internal no-flow boundaries such as shale deposits or non-conducting faults are other features that can be the determining factor in selecting gridblock size.

Porosity and permeability distribution are nearly always important and are often the keys to reservoir performance. Sensitivity studies generally indicate that if the facies distributions through the reservoir are correctly modeled and each facies is assigned the correct order of magnitude for permeability, the relatively small errors in the absolute value of permeability assigned to each gridblock are insignificant, since they are compensated for by the large area of flow that is available for fluid movement.

Constructing the entire reservoir model with a minimum size of gridblock captures the level of detail needed for critical aspect(s) of the reservoir simulation but over-compensates in non-critical areas. Subsequent inspection of the model, keeping in mind the physical processes (i.e., thermal processes) and solution techniques that will be used to model fluid flow, will identify areas of the reservoir that do not require the level of detail that was built into the original model. The process of subsequently selecting and reducing the number of gridblocks used to model the non-critical areas is referred to as "upscaling."

Selection of the appropriate timestep is generally left to last, because the pore volume of a gridblock and rate of fluid flow (production) both influence the rate of change in a gridblock's fluid saturations over time. Limits on the rate of saturation change that are developed from experience, are generally used to determine the largest timestep size that will present apparently smooth results when mapped or graphed. This process is done internally by the simulator to ensure smoothness of results.

SIMULATION OUTPUT

Since it is not possible to individually inspect the millions of calculations that are performed in a simulation, editing and graphical presentation of the output is crucial to assessing the consistency and reliability of the results. As a minimum, the output graphs should include:

- oil, water and gas production rates,
- producing gas-oil ratio;
- producing water cut or water oil ratio, and
- bottomhole flowing pressures.

Maps / movies of fluid saturation and reservoir pressure trends are also invaluable to assessing the quality and consistency of the output. For example, inconsistent pressure behaviour – related to negative cell volumes – may indicate that there is an issue with the gridding and / or assigned transmissibility of gridblocks along a fault zone.

USES AND LIMITATIONS OF SIMULATION

As computing power and software capability have developed, the "art" of reservoir simulation has proven to be a valuable complement to other methods of reservoir analysis. To the geologist, a three-dimensional model is the ultimate tool for visualizing and then communicating the reservoir interpretation to others (Figure 4). As a working tool, it integrates the partial interpretations provided by each discipline and allows for an unsurpassed level of consistency checks.

To the reservoir engineer, modern-day

reservoir simulation software provides the capability to visualize and present the movement of fluids through rock in accordance with physical principals. With it we can:

- comparatively assess the hydrocarbon recovery efficiency of various production systems that could be considered for a given reservoir prior to their implementation and
- more closely monitor producing reservoir trends and more quickly identify the probable causes of deviations from forecasted performance, particularly during the early life of a reservoir.

Prior to production, Monte Carlo volumetric estimates are still the best tool to quantify the uncertainty in the gas or oil-in-place within a deposit. But reservoir simulation allows comparison of production performance over the probable volumetric range at a level not previously available. Simulation sensitivity studies are invaluable in identifying the uncertainties that can have a significant impact on production / financial performance and in focusing efforts to acquire additional information and / or modify development plans to mitigate potential impacts.

For a producing reservoir, material balance still provides the most accurate estimates of oil- and / or gas-in-place. Accordingly, tuning the in-place volumes in the simulator to the material balance results improves the diagnoses of well performance and allows for better reservoir management.

REFERENCES

Mattax, C.C. and Dalton R.L. 1990. Reservoir Simulation. Society of Petroleum Engineers, Henry L. Doherty Series, Monograph Vol. 13.

This is the last of Fekete's articles on Reservoir Engineering for Geologists. We would like to thank the CSPG for the opportunity to present this series. We also wish to thank the members for the positive feedback we have received.

This article was contributed by Fekete Associates Inc. For more information on this series, contact Lisa Dean at Fekete Associates Inc.