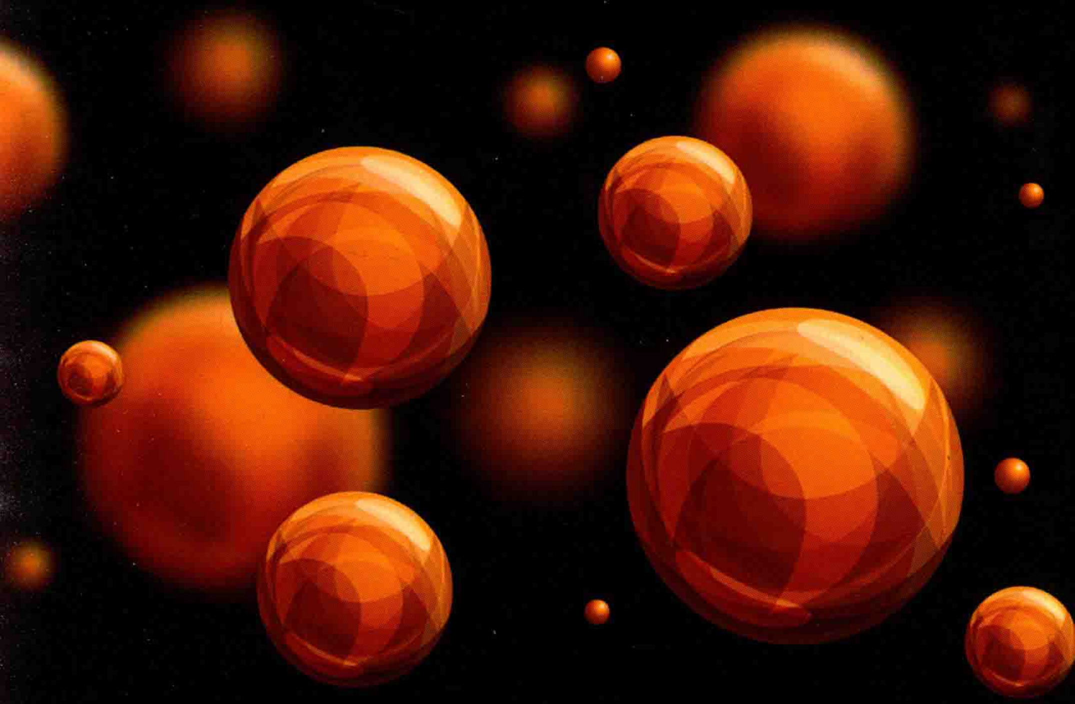

EXPERIMENTAL DESIGN IN PETROLEUM RESERVOIR STUDIES

MOHAMMAD JAMSHIDNEZHAD

Experimental Design in Petroleum Reservoir Studies

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Biography

Mohammad Jamshidnezhad is a Senior Reservoir Engineer who has worked (in Canada and Iran) for more than 14 years on carbonate and sandstone reservoirs and become specialized in reservoir engineering aspects of enhanced oil recovery (EOR), PVT, reservoir simulation and uncertainty assessments. He holds a PhD degree in chemical engineering from the University of Tehran (Iran). Mohammad was a Research Scholar in the Department of Petroleum Engineering at Curtin University of Technology in Australia in 2003 where he performed successful experiments on Enhanced Oil Recovery. He was employed as a postdoctoral researcher working on a simultaneous water and gas injection project at the Petroleum Engineering Section of the Department of Geoscience and Engineering at Delft University of Technology (The Netherlands) during 2007–2008. Mohammad has taught industry short courses in reservoir simulation, PVT, and uncertainty analysis. He is the author of several peer-reviewed journal and international conference papers.

Preface

Petroleum reservoir engineering is one of the most attractive fields at universities and colleges since most graduates find good positions in petroleum companies and work in different disciplines like estimating hydrocarbon in-place, reserve, best enhanced oil recovery methods, and reservoir management.

One of the main duties for reservoir engineers is reservoir study, which starts when a reservoir is explored and continues until reservoir abandonment. Reservoir study is a continual process, which means after a period of production the study should be updated.

A reservoir study starts with reservoir characterization: that is, gathering data (geological, geophysical, drilling and production) and building a geological model. The geological model (fine model) is upscaled and then initialized subject to initial conditions of the reservoir. The dynamic model is run by a reservoir simulator and the model results are then compared with observed (field) data. This step of reservoir study is called history matching. If the comparisons are reasonable, the model behaves similarly to the actual reservoir and it is then used for predicting the future of the reservoir. Because of reservoir complexity and limited information and data, the reservoir characterization is not conducted completely and precisely. This means that uncertainties always exist in reservoir characterization and reservoir engineers cannot define (model) a reservoir deterministically. Uncertainty in reservoir modeling causes difficulties in reasonable history matching and prediction phases of study. Quantifying and analyzing uncertainties could relieve the difficulties.

The focus of this book is on experimental design to analyze and to quantify these uncertainties. The book is divided into four chapters. In Chapter 1, an introduction to petroleum reservoirs is presented. Reservoir modeling is discussed in Chapter 2. In Chapter 3, uncertainties in reservoir modeling and experimental design methods are explained, and finally six case studies are discussed in Chapter 4. Five cases are run using black-oil reservoir simulators, and a thermal reservoir simulator is used for the sixth case. The explained case studies cover a wide range of reservoir studies: two conventional petroleum reservoirs, a fractured carbonate reservoir, steam-assisted gravity drainage (SAGD) in a heavy oil reservoir, miscible water alternate gas (WAG) into a reservoir, and a hydraulically fractured shale-gas reservoir.

Last but not least, I would like to thank Prof. Mehran Pooladi-Darvish (Fekete Associate Inc.) for initiating the concept behind this book. I would also like to thank all Senior Reservoir Engineers at the Petroleum Engineering Department of National Iranian South Oil Company (NISOC) for providing some data of the second case study. Finally, I appreciate the editorial comments provided by Dr. Alireza Jamshidnejad.

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September 2014

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Introduction

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1.1 Petroleum reservoirs

Most petroleum geologists believe that crude oil is a result of diagenesis (process of rock compaction that leads to change in physical and chemical properties of the rock) of buried organic materials and therefore is a vital characteristic of sedimentary rocks, not of volcanic rocks. Based on the views of petroleum geologists, the following five conditions generate petroleum traps [Selley, 1998]:

1. Rich source rocks of organic materials that produce hydrocarbons;
2. Source rock heated sufficiently to liberate crude oil;
3. A reservoir to collect liberated hydrocarbons, which should be porous and permeable enough to store and transfer hydrocarbons;
4. This reservoir must have impermeable cap rock to prevent hydrocarbon escaping to the surface;
5. Source rock, reservoir and cap rock should be arranged in a way that enables the trapping of hydrocarbons.

Theoretically, any sedimentary rock could be a hydrocarbon reservoir; however, in reality only sandstone (clastic sedimentary rocks composed mainly of quartz) and carbonate (rocks composed of calcite or dolomite) rocks are the main hydrocarbon resources in the world. There are also shale (a fine-grained rock composed of clay) oil and gas fields in some regions.

In contrast to sandstone reservoirs, carbonate reservoirs are sensitive to diagenesis processes and their reservoir qualities strongly depend on certain factors carried out during the diagenesis. Diagenesis processes in carbonate rocks cause fracturing, dolomitization, dissolution and cementation. Some of these processes, such as fracturing and dolomitization, improve reservoir qualities. In general, sandstone reservoirs have higher reservoir qualities in comparison to carbonate and shale reservoirs.

1.2 Petroleum rock properties

Different properties of reservoir rocks are characterized when a petroleum reservoir is studied. These properties are: mineralogy, grain size, porosity, permeability, acoustic properties, electrical properties, radioactive properties, magnetic properties, and mechanical properties.

Mineralogy and grain size: Quartz and calcite are the most common minerals in reservoir rocks. Trace minerals are often present as individual grains or as cement. Grain size and sorting can vary considerably; however, reservoir quality tends to decrease with decreased grain size. Accordingly, very finely grained rocks (such as shale) tend to have sealing properties.

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Acoustic properties: Acoustic measurements include sonic and ultrasonic ranges. The primary and most routine use of acoustic measurement in reservoir engineering is porosity determination.

Electrical properties: Studies of electrical properties in rocks are mainly performed for determination of formation resistivity and water saturation.

Radioactive properties: Geological age of a formation and the volume of shale in the formation are estimated by measuring radioactivity in rocks. The gamma logs (a tool for measuring the natural radioactivity from potassium, thorium, and uranium isotopes in the earth) are used as a shaliness indicator in petroleum reservoir studies.

Magnetic properties: Nuclear magnetic resonance (NMR), a subcategory of electromagnetic logging, measures the induced magnetic moment of hydrogen nuclei contained within the fluid-filled pore space of porous media (reservoir rocks). NMR provides information about: the volume (porosity) and distribution (permeability) of the rock pores, rock composition, and type and quantity of fluid hydrocarbons.

Mechanical properties: Mechanical properties of rocks are important in formation evaluation, drilling, development planning and production. These properties are useful in borehole stability analysis, sand production prediction, hydraulic fracture design and optimization, compaction/subsidence studies, drill bit selection, casing point selection and casing design.

Porosity: Usually petroleum rock pores are filled with connate water and hydrocarbons. Porosity is the ratio of pore volume to bulk volume and is usually reported as percentage. Two porosity values are usually measured: total porosity and effective porosity. Total porosity is the fraction of rock bulk volume that is void, whether the individual pores are interconnected or not. Effective porosity is the ratio of connected void space to rock bulk volume. It is the effective porosity that reservoir engineers are interested in and, in almost all cases, the porosity measured in the laboratory is the effective porosity.

Uniformity of grain size, degree of cementation, amount of compaction during and after deposition, and methods of packing are the factors governing the magnitude of porosity [Tiab and Donaldson, 2004].

Porosities are measured in core laboratories, as well as by using the sonic-acoustic log, the formation density log, and the neutron porosity log [Tiab and Donaldson, 2004]: In the core laboratory bulk volume, pore volume, rock matrix volume, and irreducible water saturation are measured. By knowing these parameters, total porosity and effective porosity are calculated. Commonly, mercury injection and gas compression/expansion are used to determine total porosity and effective porosity, respectively.

In the sonic log, the time required for a sound wave to travel through one foot of formation is measured. This transiting time is then correlated to the porosity.

In the formation density log, the bulk density of the reservoir rock is measured. Using bulk density, matrix density and average density of fluids filling the formation, porosity is evaluated.

The neutron log is sensitive to the amount of hydrogen atoms in a formation. In the neutron log, a neutron source is employed to measure the ratio of the concentration of hydrogen atoms in the material, to that of pure water at 75°F. This ratio (called hydrogen index, HI) is directly related to porosity.

Permeability: The second main property of a reservoir rock, after porosity, is permeability. Porous medium is not sufficient for a reservoir rock—the pores must be connected to each other. Permeability is a measure of the rock's capability to transport fluids. Primary work on permeability was done by Darcy in 1856. Darcy's law is formulated as:

$$U = \frac{k(P_1 - P_2)}{\mu L} \tag{1.1a}$$

The unit of permeability (k) is the darcy, which is the permeability of a rock transporting a fluid of 1 cp viscosity (μ) with a velocity (U) of 1 cm per second and 1 atmosphere pressure drop ($P_1 - P_2$) along a rock of 1 cm length (L). Permeability of most hydrocarbon reservoirs is much less than one darcy, so the unit of millidarcy (0.001 darcy, abbreviated "md") is usually applied.

For laminar gas flow through porous media, Darcy's law is shown as:

$$U = k(P_1^2 - P_2^2)/(2\mu \cdot L \cdot P_{\text{ave}}) \tag{1.1b}$$

The permeability of a hydrocarbon reservoir is measured (or estimated) using one of the methods described in the following paragraphs.

The first method is by using well testing data. In a well test, by changing the flow rate of a well, variation in well bottom-hole pressure is recorded as a function of time. The flow rate of a well is changed by increasing or decreasing the rate. The pressure change is analyzed by plotting the recorded pressure and its derivative versus time. The two most common tests are the buildup and drawdown tests. In a buildup test the well is shut in after a period of production and then its pressure is measured. In a drawdown test the pressure is measured in a well that is open after a period of well shutting in.

The second method is measuring the permeability in a core laboratory. A known gas (air or nitrogen) is injected into a core (or a plug) at controlled velocity and then the pressure drop is measured. Using Darcy's law (Eq. 1.1b), permeability is calculated and it is then extrapolated to the zero value of the reciprocal pressure ($1/p$) to estimate liquid (oil or water) permeability.

In the presence of more than one fluid, permeability is referred to as the *effective permeability*. In this case, the ratio of effective permeability of any phase to the absolute permeability of the rock is called the relative permeability (k_r) of that phase. Darcy's law for multiple phase flow through the rock is formulated as:

$$Q_p = \frac{-kk_{rp}A}{\mu_p}\left(\frac{\mathrm{d}P}{\mathrm{d}x}\right)_p \tag{1.2}$$

where the subscript p denotes phase.

Shape and size of grains, lamination, cementation, fracturing and solution are the factors governing the magnitude of porosity [Tiab and Donaldson, 2004].

1.3 Volumetric calculations in a reservoir

In oil reservoirs, the original oil in place (OOIP) is calculated as:

$$OOIP = V_b\varphi(1 - S_{wc}) \tag{1.3}$$

where V_b is the bulk volume of reservoir rock, φ is the average porosity of the reservoir rock and S_{wc} is the average connate water of the reservoir rock.

The bulk volume, V_b, is obtained from geological, geophysical and fluid pressure analysis. The product $V_b\varphi$ is called the pore volume (PV) and is the total volume that may be occupied by fluids. Similarly, $V_b\varphi(1 - S_{wc})$ is called the hydrocarbon pore volume (HCPV) and is the total reservoir volume that may be filled with hydrocarbons.

The oil volume calculated using Eq. 1.3 is usually expressed as stock tank oil initially in place (STOIIP) as:

$$STOIIP = N = V_b\varphi(1 - S_{wc})/B_{oi} \tag{1.4}$$

where B_{oi} is the initial oil formation factor.

Although the amount of hydrocarbons inside a reservoir is a constant quantity, the reserve (i.e., recoverable oil and gas) depends on the production technique. Theoretically, the maximum amount of oil that may be removed from a reservoir is called movable oil volume, MOV, and is calculated as:

$$MOV = V_b\varphi(1 - S_{or} - S_{wc}) \tag{1.5}$$

In this equation, S_{or} is the residual oil saturation that depends on the recovery mechanism.

Three hydrocarbon recovery mechanisms are used, respectively, in a petroleum reservoir:

- Primary recovery, or natural depletion, where the volume of hydrocarbons may be produced utilizing the natural energy of the reservoir. Natural energies come from one or more of the following: gas cap expansion (gas cap drive), aquifer expansion (water drive), pore compaction, fluid expansion, solution gas.
- Secondary recovery, where the volume of recovered hydrocarbons is incremented by injecting water or immiscible gas (hydrocarbon gas such as methane or non-hydrocarbon gas such as nitrogen, carbon dioxide) into the reservoir. Alteration injection of water and immiscible gas is also considered as a secondary recovery mechanism.
- Enhanced oil recovery (EOR), where the volume of recovered hydrocarbons is raised by injecting chemicals, hot water, steam and surfactants into the reservoir. In an EOR process, chemical and/or physical properties of reservoir oil and rock may change.

1.4 Reservoir heterogeneity

In contrast to homogeneous reservoirs, geological and petrophysical properties of heterogeneous reservoirs vary with position. More variations in reservoir properties result in more heterogeneity. Reservoir properties variation means that there is no homogeneous petroleum reservoir in the real world. In other words, all petroleum reservoirs are heterogeneous but the degree of heterogeneity is different from one reservoir to another. Usually, the degree of heterogeneity in sandstone reservoirs is less than in carbonate reservoirs. Figure 1.1 shows a typical heterogeneous reservoir, where the permeability varies from 10 md to 1000 md.

Among the petroleum reservoir properties, heterogeneity of reservoir rock properties affects more than reservoir fluids. Fanchi (2010) and Schulze-Riegert and

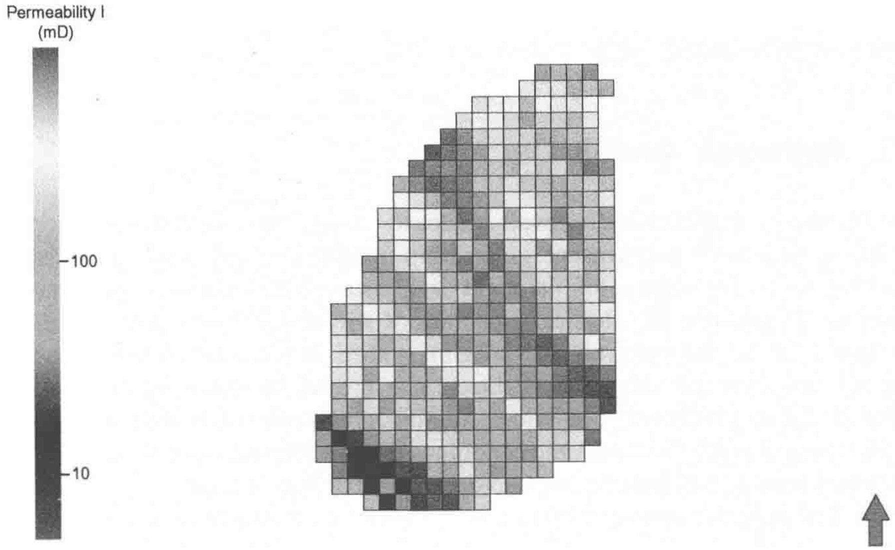

Figure 1.1 Permeability variation in a typical heterogeneous reservoir, (view from top).

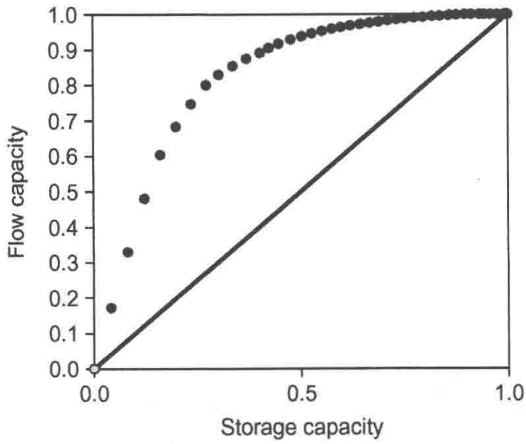

Figure 1.2 Typical Lorenz plot.

Ghedan (2007) summarized four levels of reservoir rock heterogeneities as microscopic (for the scale of 10–100 μm), macroscopic (for the scale of 1–100 cm), mega-scale (for the scale of 10–100 m) and giga-scale (for the scale of greater than 1000 m). It should be noted that degree of heterogeneity along the reservoir length is different from the vertical direction; some properties such as porosity and permeability have a higher degree of heterogeneity in the vertical direction.

There are a few methods to determine degree of heterogeneity. Among them, the Lorenz method, where the cumulative flow capacity, $\Sigma(kh)$, is related to the cumulative storage capacity of the reservoir, $\Sigma(\varphi h)$, is a common method. Figure 1.2 shows a typical Lorenz plot. The greater the deviations of this curve from the 45° line, the greater the heterogeneity of the system.

1.5 Reservoir models

Construction of a petroleum reservoir model for improving estimation of reserves, predicting reservoir performance, increasing production and making decisions regarding the development of the field is a meaningful definition of reservoir modeling. Shape, size and physical properties of a reservoir model should be a representative of the real reservoir that is being studied. If reservoir modeling is done properly and correctly, reservoir engineers can predict the reservoir performance under different production scenarios. Approval reservoir static values (such as hydrocarbon in-place) and dynamic conditions (such as production and well productivity drop) are also obtained using appropriate reservoir modeling.

The first step in reservoir modeling is reservoir characterization, where required data are gathered, analyzed, and the static model is constructed. Thus, to construct an appropriate reservoir model, there should be two necessities: 1) size and properties of the reservoir should be known (in reservoir modeling this phase is called reservoir characterization), and 2) equations of fluid flow through porous media should be solved accurately. In practical applications, there are some limitations to these requirements: first, no one is able to measure or examine all reservoir properties, and second, some of the rules and phenomena of fluid flow through porous media are still incomplete. Also, numerical methods to solve the equations of fluid flow have their own limitations. Among these limitations, the reservoir characterization phase has the most restrictions (or, as a more correct sentence, has the most uncertainties).

Schulze-Riegert and Ghedan (2007) mentioned three sources for uncertainties in reservoir modeling: measuring errors, mathematical errors, and incompleteness of data. In brownfields (where there are histories of pressure and fluid production), one way to overcome the errors and incompleteness is to change the reservoir properties so that field data (pressure and fluid production) and model results are matched. This method is called history matching. Once the model historically matches field data, it may behave the same as the actual reservoir under future constraints.

However, history-matching suffers from three difficulties:

- The solutions of fluid flow equations are known (we know the pressure and production data), but the input parameters (reservoir properties) are uncertain. Thus, we can say that history matching is an inverse problem and therefore could have several solutions. Figure 1.3 illustrates a history-matching case where two models with different parameters are matched with observed data.
- It is a time-consuming phase and occupies a large portion of a reservoir study time. Experience shows that normally 40% of the time for a reservoir study is spent on history-matching.
- Sometimes unrealistic reservoir properties are needed to achieve a history-matched model [Satter and Thakur, 1994]. Figure 1.4 depicts water relative permeability data needed for a case seeking a successful history-matched model.

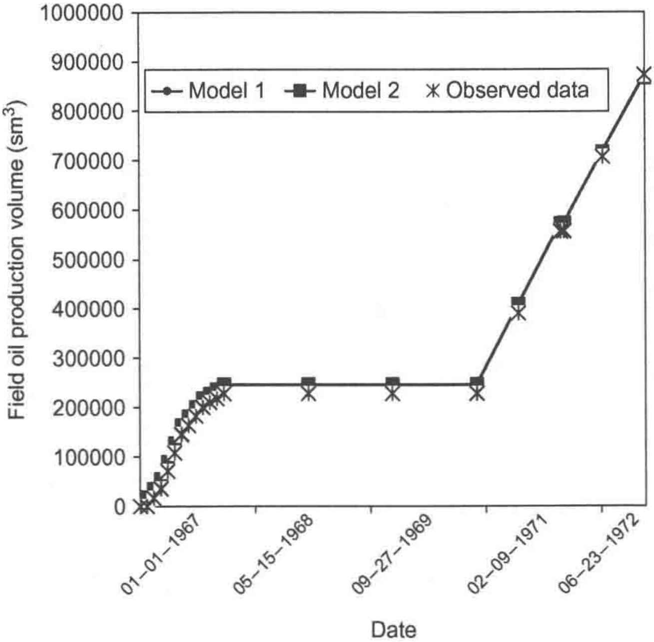

Figure 1.3 Two models with different parameters are matched with observed data.

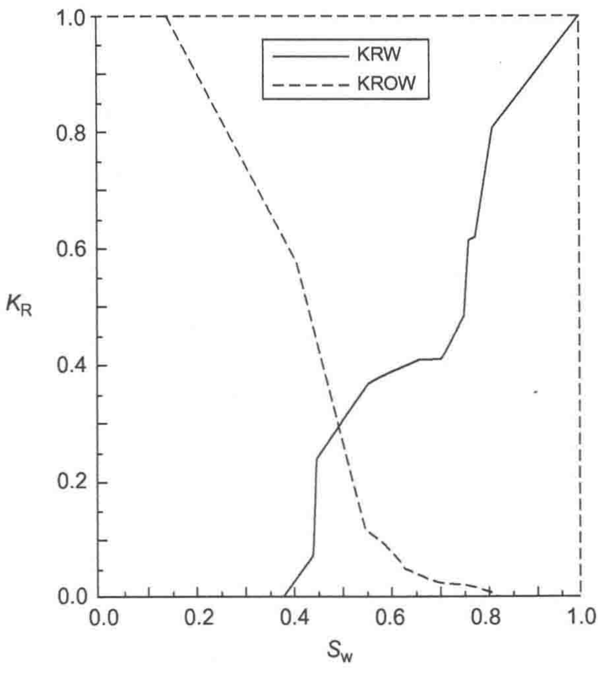

Figure 1.4 Unrealistic water relative permeability data for a successful history-matching case.

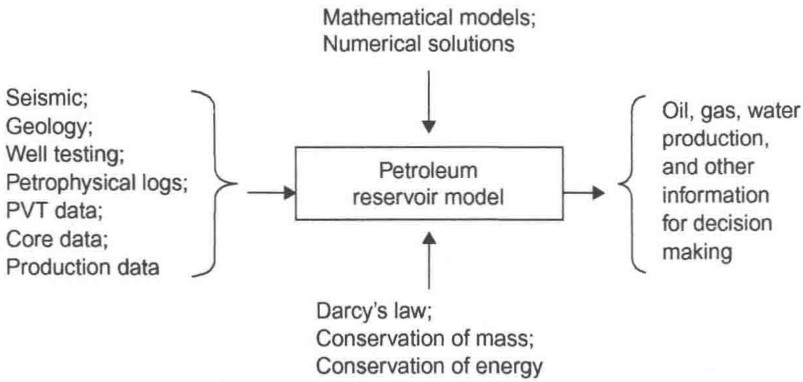

Figure 1.5 General diagram of reservoir modeling.

In the next chapters, the procedure of reservoir modeling and history-matching are thoroughly explained.

1.6 Experimental design

Experimental design is a viable tool to acquire knowledge and to optimize reservoir processes at minimum cost and time [Montgomery, 2001]. It is a statistical method to study cause-effect and phenomena-response relationships in processes and phenomena [Lazić, 2004].

As the behavior of a petroleum reservoir is controlled by the interactions of various factors, experimental design can be used to study the effects of one or more factors on reservoir performance. Figure 1.5 illustrates a general model for reservoir modeling.

By using experimental design, reservoir engineers are able to condition the reservoir and to adjust the most influential factors (parameters), so that the reservoir model is history matched, the hydrocarbon production is maximized, and the reservoir is at its optimum conditions.

This book claims that experimental design could be used to improve reserve estimation, to do history matching with fewer difficulties, to predict reservoir performance with more reliability, to increase production, and to make effective decisions regarding the development of the field. The methodology of experimental design is explained in detail in Chapter 3.

Reservoir modeling

2

2.1 Introduction

Reservoir modeling means construction of a petroleum reservoir model for improving estimation of reserves, predicting reservoir performance, increasing production and making decisions regarding the development of the field. The main purpose of reservoir modeling is reservoir management. Reservoir modeling involves teamwork and people of different disciplines—geophysics, geology, petrophysics, mathematics, chemical and petroleum engineering—working together to construct a corresponding model.

A reservoir model consists of the following main parts: defining and specifying of objectives; data gathering and data analysis; building the reservoir model; conducting history-matching; conducting forecast scenarios; and reporting. The most important step in a successful reservoir study is to specify the objectives. The type and border of the model, quantity of data, quality of history-matching and forecast scenarios all depend on the objectives of the study. In specifying the objectives, the recovery mechanisms, quantity and quality of the available data and the schedule of the study have to be addressed properly.

One of the main factors in specifying the objectives of a study is to determine the recovery mechanisms of the reservoir, as reservoir modeling is only able to answer questions about the production history. Even if the reservoir model matches the field history of a reservoir with natural drive mechanisms, model results for secondary and tertiary processes are not reliable. This is because the mechanisms of primary (natural) recovery differ from the secondary and tertiary. For example, if there is an undersaturated petroleum reservoir with some impermeable shale layers and without an active aquifer, the primary recovery mechanism of the reservoir is fluid expansion and pore compaction. Therefore, the shale layers are not so important in fluid production from the reservoir. However, if after a period of fluid production water is injected into the reservoir (secondary recovery), the presence of impermeable shale layers is important. So, for a reliable forecast result from the reservoir model, a corresponding history is important. When defining the objectives of the study, quality and quantity of available data should be considered; for example, to have reliable modeling results of a gas injection scenario, reliable gas relative permeability data and capillary pressure data are essential.

Performance of hydrocarbon reservoirs is modeled by three methods: analogy, laboratory and mathematical methods. By the analogy method, reservoir characteristics of a similar reservoir are used rather than the original reservoir. This method is usually applied when the data of the original reservoir are meager. In laboratory methods, reservoir behavior is studied at laboratory scale and the results are then scaled up to the reservoir scale. Scaling up from laboratory to field is the most challenging issue when using laboratory methods. In mathematical methods, equations

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