A Project Report On

RESERVOIR SIMULATION ON WATER FLOODING OPTIMIZATION

Submitted in Partial Fulfillment of the Requirements for the award of the Degree of

BACHELOR OF TECHNOLOGY

In

PETROLEUM ENGINEERING

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Certified that this project report **"RESERVOIR SIMULATION ON WATER FLOODING OPTIMIZATION"** is bonafied work of **LATH MELES AUGUSTIN (186R1A2726), B. RAKESH REDDY (186R1A2713) , M. HAZEE (196R5A2705),** who carried out the project work under my supervision during the year 2021 to 2022, towards partial fulfillment of the requirements of the Degree of Bachelor of Technology in Petroleum Engineering as administered under the Regulation of GIET College of Engineering, Rajamahendravaram, AP, India and award of the Degree from Jawaharlal Nehru technological University, Kakinada. The results embodied in this report have not been submitted to any other University for the award of any degree.

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I solemnly declare that this project report **"RESERVOIR SIMULATION ON WATER FLOODING OPTIMIZATION"** is the Bonafide work done purely by us, carried out under the supervision of Mr. Nagur Vali Shaik towards partial fulfillment of the requirements of the Degree of Bachelor of Technology in Petroleum Engineering as administered under the Regulations of GIET college of Engineering, Rajamahendravaram, AP, India and award of the Degree from Jawaharlal Nehru Technological University, Kakinada during the year 2021-2022

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ACKNOWLEDGEMENT

We take great pleasure to express our deep sense of gratitude to our Guide **Mr. NAGUR VALI SHAIK, Assistant Professor,** for his exhilarating supervision, timely suggestions and encouragement during all phases of this work.

We would like to thank our Head of the Department **AHAMMAD SHARIF Md, M. Tech,** of Petroleum Engineering for his encouragement.

We would like to express our thanks to **Dr. T. VAMSEE KIRAN,** Principal, **Dr. S. SRI GOWARI REDDY,** PhD, Vice Principal of **GIET COLLEGE OF ENGINEERING, RAJAHMUNDRY** for providing all the facilities for our project.

Our outmost thanks to all the Faculty Members and non-Teaching staff of the Department of Petroleum Engineering for their support throughout our project work.

Our Family Members and Friends receive our deepest gratitude and love of their support throughout our academic year.

RESERVOIR SIMULATION

ON WATER FLOODING OPTIMIZATION

ABSTRACT

Fluid flow in a petroleum reservoir is a very complex phenomena and it is impossible to develop analytical solutions for practical issues due to the complex behavior of multiple-phase flow. Reservoir simulation is an important tool that can be used to simulate as well as predict production from shale reservoirs, and also predict the future performance of the reservoir for that the useful techniques can be made to optimize the economic recovery of hydrocarbons from the reservoir. Reservoir simulation is an area of reservoir engineering where computer models are used to forecast flow of fluid through porous media. The types of reservoir simulation models use are significant in this process. Black-oil, compositional simulators, thermal, single-porosity or dual porosity (for fractured reservoir) can be used for reservoir simulation. Simulating thermal is usually computationally expensive because of the complexity of the problem and strong nonlinearities encountered. For thermal streamline simulation, we first focus on the extension to hot water flood processes in which we have temperature induced viscosity changes and thermal volume changes. In other hand, thermal reaction reservoir simulation, mass energy balance equations are solved numerically on discretized reservoir grid blocks. Usually, single-porosity parameters, which can be used to describe dual porosity reservoirs. The black-oil simulations are widely easier and less time consuming than compositional simulations. However, black-oil simulation results compared to compositional simulation results. Single-phase and two-phase black-oil simulation results as well as compositional simulation results were analyzed and compared in this project, for that, an approach to water flood optimization must be applied to facility the understanding of the process.

Table of Contents

LIST OF FIGURES

LIST OF TABLES

NOMENCLATURE

A	Area
Bo	Oil formation volume factor
Bg	Gas formation volume factor
Bw	Water formation volume factor
Boi	Initial oil formation volume factor
Bgi	Initial gas formation volume factor
B	Neighbor to cell a in some direction
Cf	Rock compressibility factor
Cw	Water compressibility factor
Ct	Total compressibility
D	Dimension (1D, 2D, 3D and 4D)
d	Differential (PVT analysis)
Gi	Cumulative gas injection
GOR	Gas Oil Ratio
K	Cell permeability
Ka	Absolute permeability
Ke	Effective permeability
Kr	Relative permeability
Kro	Function of oil saturation
Krg	Function of gas saturation
Krw	Function of water saturation
Keok	Effective permeability of oil function

Kegk	Effective permeability of gas function
Kewk	Effective permeability of water function
Kibc	Inter bounds of effective permeability
Kobc	Outer bounds effective permeability
K(true)	True effective permeability
Pinj	Water injection pressure
Pc	Capillary pressure
iw	Water injection ratio
Pi	Production index
Pv	Pore Volume
IP	Injection to producer ratio
Rp	Dissolved gas produced GOR
Rs	Dissolved gas solution GOR
Rsi	Initial dissolved gas GOR
So	Oil saturation
Sg	Gas saturation
Sw	Water saturation
S	Fluid saturation
Swc	Connate water saturation
T	Absolute temperature
U	Aquifer constant
u	Viscosity
V	Volume

v	Net bulk volume of reservoir
Vg	Cumulative relative gas volume (sc),
	Differential liberation PVT experiment width
We	Cumulative water influx
Wiw	Initial volume of aquifer water
Wi	Cumulative water injection
Δp	Pressure drop
Δ	Difference (taken as a positive difference e.g $\Delta p=pi-p$)
Δx	Dimension x direction
Δy	Dimension y direction
Δz	Dimension z direction

1. INTRODUCTION

In general, reservoir simulation is an area of reservoir engineering in which computer models are used to predict the flow fluids (typically, oil, water and gas) through porous media. Understanding the recovery technical limit and current predicted recovery, and then evaluate and select future recovery options (new wells, enhanced oil recovery, etc.) to maximize economic recovery; simulators for various recovery processes have been developed and continue to be developed for new oil processes. Reservoir simulation is the art of combining physics, mathematics, reservoir engineering, and computer programming to develop a tool for predicting hydrocarbon performance under various operating strategies. Static and dynamic reservoir models are key elements for evaluating and selecting any future recovery options (Infill wells, improved oil recovery, enhanced oil recovery). A model (static and dynamic) describing the distribution and characterization of hydrocarbon in place and reserves, they are key elements of a good reservoir management program. Reservoir simulation models are used by oil and gas companies in the development of new fields. Also, models are used in developed fields where production forecasts are needed to help make investment decisions. The reservoir simulation technique makes it possible to gain insight into the recovery processes of a reservoir. To understand fluid flow and , by this, to evaluate the performance of oil and gas recovery methods, the petroleum engineer models, the intervention of physical and chemical processes by systems of partial differential equations. These equations account for mass and heat transfer. For new field models may help development by identifying the number of wells required, the optimal completion of wells, the present and future needs for artificial lift, and the expected production of oil, gas and water.

1.1. What Is a Petroleum Reservoir?

A petroleum reservoir is a term that is used to describe the accumulation of crude oil in a defined location. Usually, the location where the crude oil may have formed is often underground or beneath the sea or ocean floor. These formations are the result of the decomposition of organic matter over the course of centuries, which is why the fuel or energy that is derived from such is known as a nonrenewable source of energy. This means any depletion of such a deposit cannot be replenished the same way in the foreseeable future, making it absolutely necessary for other sources of energy to be developed to take the pressure off the fast-depleting global petroleum reservoir that has been subjected to intense demand from consumers of energy.

A petroleum reservoir may be discovered by accident, as has happened when the oil seeps to the surface or when the oil seeps into water supply, consequently revealing its presence in that location. Other times, it is often necessary to intentionally explore different regions through the application of scientific and geographic knowledge with the view of discovering other places that may contain petroleum reservoir. Some regions of the world have vast crude oil deposits or are blessed with the presence petroleum reservoir within their geographic territory. Where this is the case, such countries can expect to make a lot of money from the sale of the oil both in its crude and refined state.

Indeed, some oil companies dedicate a lot of resources in the form of manpower, economic and material resources to the discovery of any form of petroleum reservoir. Some of these oil companies have expensive oil rigs located on both onshore and offshore facilities where they are utilized in drilling holes that go down many feet into the ground as part of the process of extracting the crude oil from the reservoir. Even though the presence of a petroleum reservoir is considered a stroke of good fortune by the residents of that area due to the economic benefits, some members may not be quite as thrilled due to the negative environmental and adverse health consequences associated with the various processes of drilling for the petroleum. For example, the practice of gas flaring is one that releases noxious fumes into the environment, and the many cases of oil spills also contribute to the detrimental effects associated with petroleum reservoir exploration.

1.2. What is Simulation?

Simulation is the process of building and using a time-based visual model that emulates every significant step that occurs in a process and every significant interaction between resources in a process so as to gain insight about the impact of potential decisions on that process. The simulation shows you visually what will happen in the process if you make changes to it and it records performance measures of your system under different scenarios.

1.3. What is Reservoir simulation?

The Merriam-Webster Dictionary defines simulate as assuming the appearance of without the reality. Simulation of petroleum reservoir performance refers to the construction and operation of a model whose behavior assumes the appearance of actual reservoir behavior. A model itself is either physical (for example, a laboratory sand pack) or mathematical. A

mathematical model is a set of equations that, subject to certain assumptions, describes the physical processes active in the reservoir.

Although the model itself obviously lacks the reality of the reservoir, the behavior of a valid model simulates—assumes the appearance of—the actual reservoir. The purpose of simulation is estimation of field performance (e.g., oil recovery) under one or more producing schemes. Whereas the field can be produced only once, at considerable expense, a model can be produced or run many times at low expense over a short period of time. Observation of model results that represent different producing conditions aids selection of an optimal set of producing conditions for the reservoir.

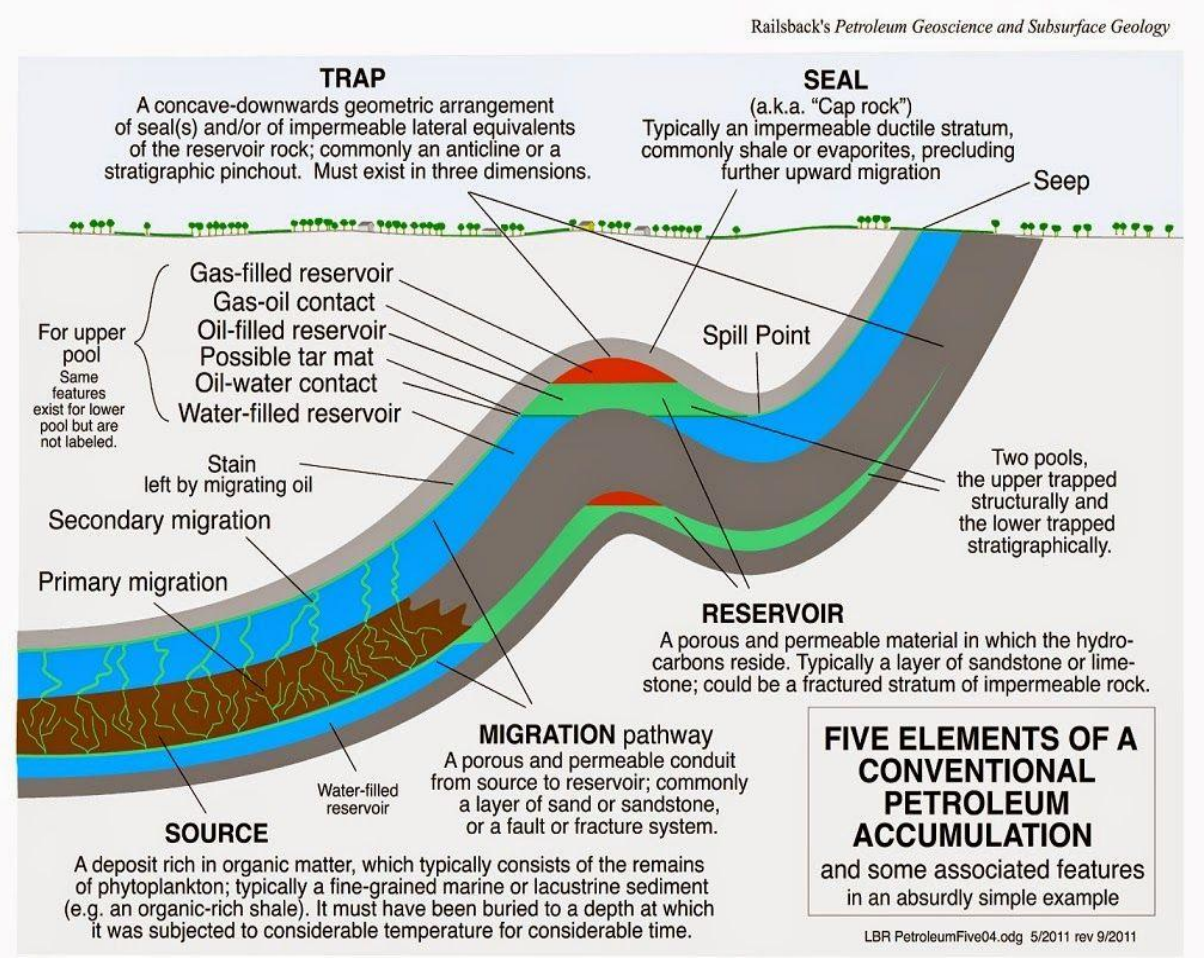

Figure 1 Petroleum Reservoir Diagram

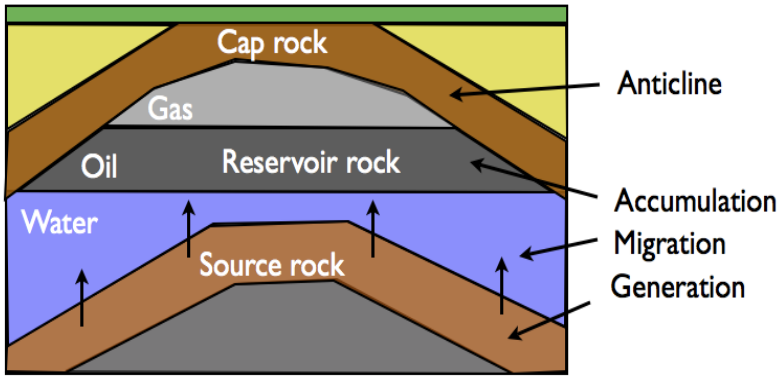

Figure 2 Origin of Hydrocarbon

1.4. What are the different types of reservoir simulation models?

Reservoir simulation models are often referred into four categories of models,

- Black-oil model
  - i. Pressure depletion
  - ii. Water flooding
  - iii. Solution-Gas injection
  - iv. Polymer flooding.
- Compositional model
  - i. Miscible/Immiscible gas (CO2) injection.
- Thermal model
  - i. Steam flooding in-situ combustion.
- Single-porosity or dual-porosity model (for fractured reservoirs)

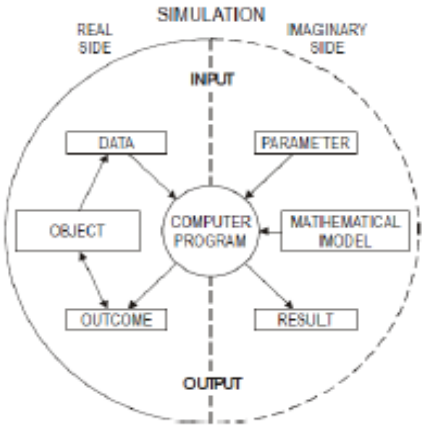

Figure 3 Combination of physical, mathematical, reservoir engineering and computer programming

2. LITERATURE REVIEW

This chapter includes the review of research work (research papers) in short. The papers reviewed illustrate use of Monte Carlo methods in diverse fields. Some papers are also based on survey of Monte Carlo methods. Thus, the literature reviewed will help me in planning the research. Reservoir simulation, or modeling, is one of the most powerful techniques currently available to the reservoir engineer.

- **Raychaudhari (2008),** This paper, briefly describes the nature and relevance of Monte Carlo simulation, the way to perform these simulations and analyze results, and the mathematical techniques for performing these simulations. Monte Carlo simulation is a very useful mathematical technique for analyzing uncertain scenarios and providing probabilistic analysis of different situations. Various software's have shown positive Monte Carlo simulation in different domains including mathematics, engineering, finance etc.
- **Joy et.al (1996),** This paper introduces and illustrates a new version of the Monte Carlo method that has attractive properties for the numerical valuation of derivatives. The traditional Monte Carlo method has proven to be a powerful and flexible tool for many types of derivatives calculations. Under the conventional approach pseudo-random numbers are used to evaluate the expression of interest. The use of pseudo-random numbers yields an error bound that is probabilistic which can be a disadvantage. Another drawback of the standard approach is that many simulations may be required to obtain a high level of accuracy. This paper suggests a new approach which promises to be very useful for applications in finance. Quasi-Monte Carlo methods use sequences that are deterministic instead of random. These sequences improve convergence and give rise to deterministic error bounds.
- **Huseby et. Al (2004),** The paper shows how Monte Carlo methods can be improved by putting constraints on a variable or vector. It shows that Different choices of variables to condition may lead to different approaches. Paper shows that simulating from the conditional distribution can be as efficient as simulating from the unconditional distribution. The paper also discusses special case of Material balance equation variables. and for this case the reliability evaluation can be improved further. Paper presents a simulation algorithm which enables us to estimate the entire system reliability polynomial expressed as a function of the common component reliability.

According to the authors if component reliabilities are not too different from each other, a generalized version of the improved conditional method can be used in combination with importance sampling. Paper concludes that the two conditioning methods can be combined in order to get even better results.

Data which we have been collected to build simulations like SPE9 Reservoir model is taken from OPM(Open Porous Media) datasets which is an open source.

3. MODEL BUILDING WORKFLOW

Reservoir simulation model is one of the major "building blocks" in an integrated reservoir modeling process.

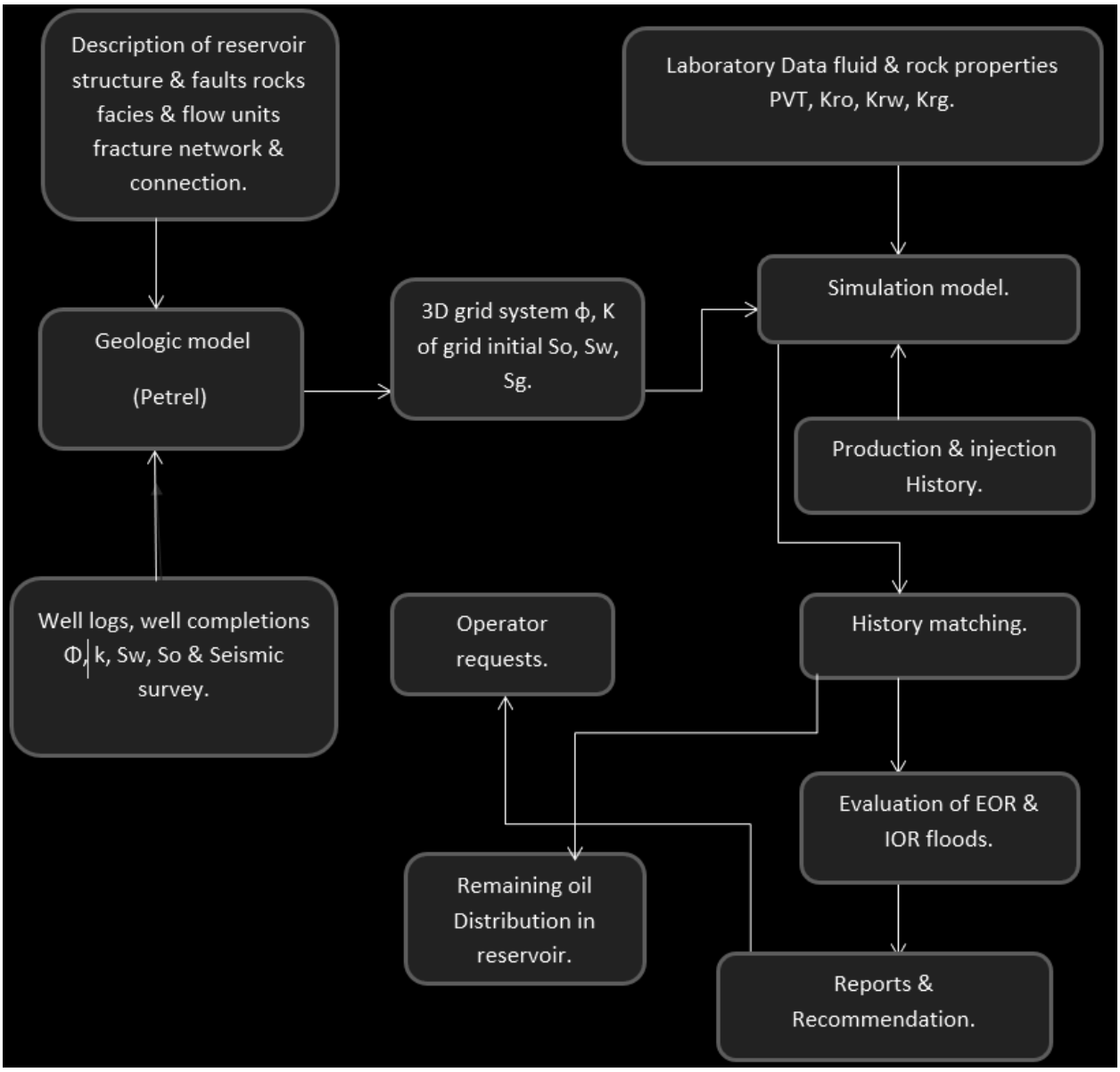

Figure 4 Typical workflow in reservoir modeling & simulation

The particular technique used for 3D reservoir modeling depends on the reservoir type. For layer-cake reservoirs, deterministic models can often be made directly from the well-to-well correlations and the rock properties can be interpolated. Computer systems have been developed to generate a series of equally probable 3D models through 'probabilistic' modeling techniques. Most systems work in three steps. Firstly, correlatable reservoir bodies are determined and incorporated in the model. Where extrapolations beyond control points are necessary, use is made of an analogue database for the relevant genetic type. Secondly, the uncorrelatable bodies are considered, for which the dimensions are also derived from the

database, while body orientations are taken from borehole imaging logs or estimated on the basis of the general geological model. Characteristic variograms for the thickness distribution of genetic sand body types in different orientations relative to their expected trend are also used. Thirdly, especially when the well spacing is rather large, there are smaller or narrower reservoir bodies not penetrated by wells. Jigsaw-type reservoirs are also difficult to correlate in the appraisal stage and probabilistic modeling is required. In a later stage, a large part of the architecture may be determined and only limited recourse has to be taken to probabilistic techniques.

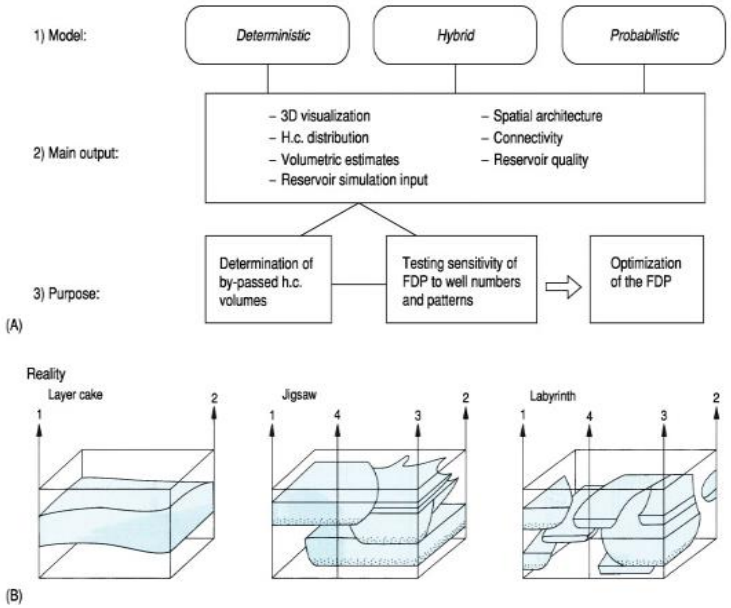

Figure 5 Summary of 3D reservoir modeling

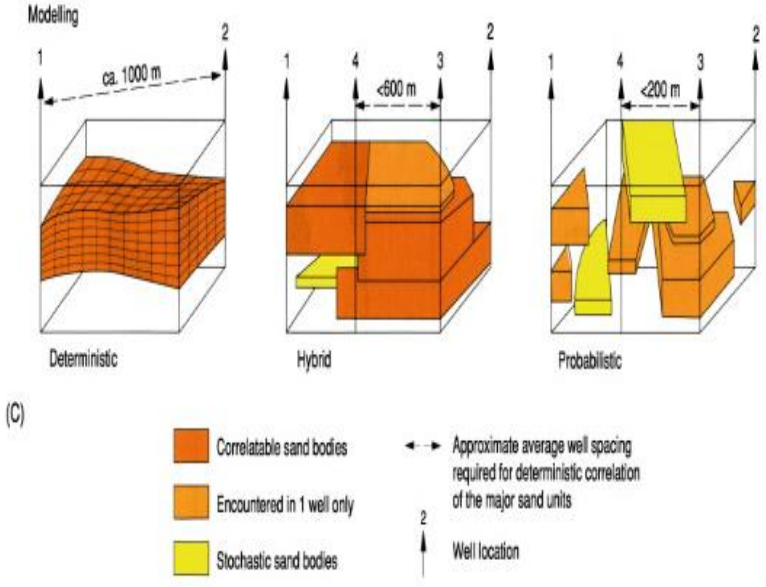

Figure 6 3D reservoir models

4. RESERVOIR SIMULATION GRID CONSTRUCTIONS

The aim of gridding in reservoir simulation is to turn the geological model of the field into a discrete system which the fluid flow equation can be solved.

Regular Cartesian Grids

A simple 3D grid is the regular Cartesian grid. Cell in such a grid may be simply identified using their (i, j, k) index values.

Each of the grid elements will be assigned a single permeability or porosity value. In this case, it's possible to obtain the transmissibility value as a harmonic average

$$T_{ap} = \frac{1}{\frac{1}{T_a}+\frac{1}{T_b}}$$

$$T_a = K_a \times \frac{A_a}{(\frac{d_a}{2})}, T_b = K_b \times \frac{A_b}{(\frac{d_b}{2})}, \ldots\ldots\ldots\ldots\ldots\ldots$$

where,

Cell b is the neighbor to cell a in some direction.

K is the cell permeability in that direction.

A is the area of the cell orthogonal to the direction of flow.

D is dimension of the cell in that direction.

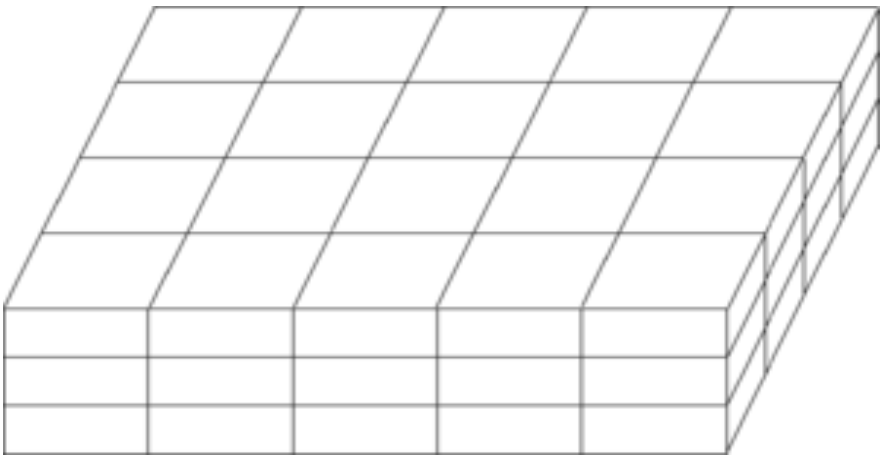

Figure 7 Regular Cartesian grids

Although regular grids are normally defined in normal Cartesian coordinates, it is also possible to use an (r, Φ, z) radial system. The resulting grid is *cylindrical* and is important for the special case of near-well studies dominated by radial inflow. For a 3D system, regular grids yield seven-point schemes, in which the flow equations for a cell involve solution values for just the cell and its six neighbors. Not all the elements in the grid need represent active solution

variables in the simulation. Some cells may be inactive, representing volumes of the reservoir with zero porosity. Such inactive cells are usually compressed out of reservoir simulation solution arrays prior to the memory and time-intensive flow solution stage, and enable reservoirs with irregular boundaries to be represented within extended simulation grids.

The horizons that delimit rock strata are generally not horizontal, but are dipped, curved, or faulted. Unless extremely fine, a true regular grid that is orthogonal in all three axes will be unable to assign rock properties accurately to cell volumes.

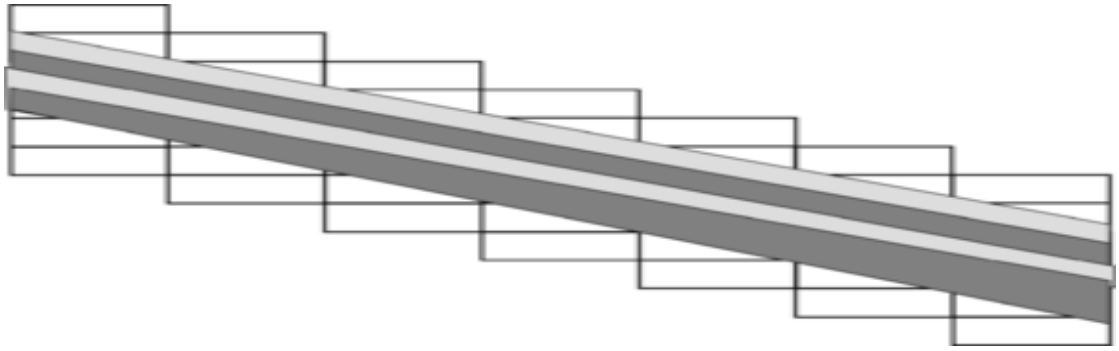

Figure 8 Orthogonal Grid used to represent dip

Hexahedral Girds

Further improvements in geological modeling threw an emphasis on describing faults, and made it important to distinguish depth displacements due to dip and faulting. This is difficult in block Centre geometry in which the cell is positioned by its Centre depth and Δx, Δy, Δz dimensions. To define faulting more precisely it is useful to define the position of grid cell by its corner point locations. A hexahedral shape with eight corners and bilinear planes as surfaces then describes the cell geometry. Faults, both vertical and inclined, may be described precisely.

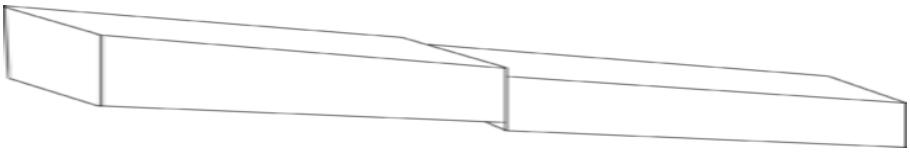

Figure 9 Hexahedral grids system

In both the dipped and general hexahedral grids, the orthogonality of a completely rectangular grid no longer exists, and the result is that the two-point property of the flows between the cells is lost—the flow between cell a and cell b is not just a function of the solution values of cells and *a* and *b*.

Grid Refinement

A common requirement in reservoir simulation is an increased level of detail around an item of interest such as a well. This is frequently obtained in structured grids by local grid refinement, replacing a set of cells in the original grid by a finer grid. Local refinement may be regarded as a form of multiple domain structured grid, in that it consists of a number of linked structured grids. Flows at the edges of local refinements generally take a multipoint form.

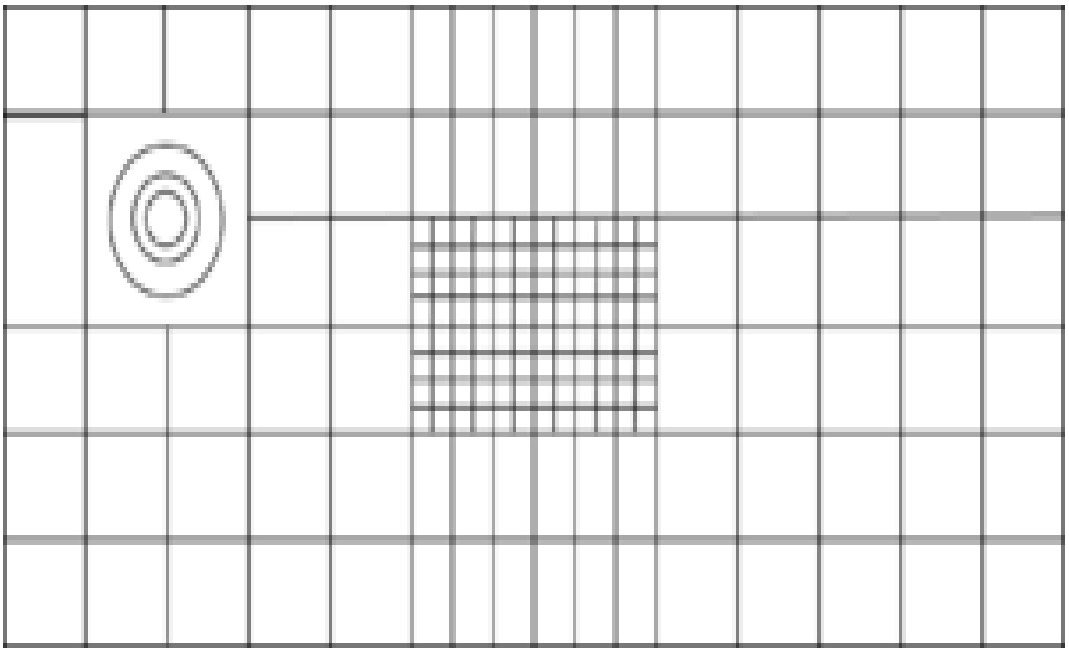

Figure 10 Grid refinement

4.1. Input Data from Geological Modeling

Input data from geological modeling includes: Structural modeling (geological grid, faults and fault properties, reservoir zonation, vertical communication, fluid contacts) property modeling (porosity, permeability, net-to-gross ratio, initial water saturation, end-point fluid saturations).

4.2. Areal Grid and Layering

To represent spatial variation in the reservoir properties, gridlocks must be smaller than the features being represented. For example, representing sinuous channels requires that the grid block dimensions be at most one-third of channel width. In the absence of specific geologic objects, a rule of thumb is that the reservoir simulation cell dimension should be approximately

twice that of the geological model cell in X- and Y-directions in areas where hydrocarbons and wells are presented.

Variation of saturation and pressure around the wells depend strongly on reservoir description, fluid properties and flow rates. Therefore, the best way to decide on grid resolution near the wells is to conduct a gridding study in a finer scale element model representing the area around a well.

Another issue is the proper representation of fluid contacts. A thin oil rim cannot be resolved in the layer thickness or areal grid-block size if it is larger than the dimensions of the oil rim.

Layering style in the reservoir simulation model usually is set to be the same as that in the geological model. The objective in layer selection is to determine the number of layers to preserve the heterogeneity seen in the geological model. Choice of layering is also affected by the displacement processes. It is important that the layers in the model be thin enough to resolve the location of well completions and vertical movement of fluid to those completions.

In terms of reservoir simulation, areally distributed flow units comprise the basic building blocks of the geological model. Numerical models allow flow to occur in three dimensions through the faces of a block ("grid block") of reservoir material. The nature of the reservoir material within any defined flow unit is not consequential, provided that the capillary pressure, relative permeabilities, and endpoint saturations are the same or very similar. Rock units with these similar characteristics are referred to as "rock types". The numerical model requires identification of barriers and changes in the rock type to track flow. Hence, the issue of depositional facies per se can be irrelevant (especially in intervals with significant diagenesis). There may be several rock types within a reservoir, which may or may not coincide with specific facies. There may be more than one rock type within a flow unit. If present, the distribution of the multiple rock types within the flow unit (layer) does have to be accounted for in the static model.

Flow layers are usually required in simulation, even in homogeneous media, in order to history match pressures and track saturation histories. If the geologist has no useful boundaries by which to separate the column into vertical units, the engineer can mathematically subdivide the column and, accordingly, assign constant petrophysical property values to the cells. In practice, this rarely happens, as almost all real-world examples provide some basis for vertical segregation into intervals that have a geological identity.

4.3. Vertical Communication

Vertical communication between reservoir simulation grid layers is important for describing correct flow displacement in reservoirs, both vertically and areally. This input should be based on the structural and Petro physical analysis and should provide vertical transmissibility multipliers to be used in the reservoir simulation model.

4.4. Faults and its Properties

Fault is a fracture or crack where two rock blocks slide past one to another. If this movement may occur rapidly, it can be causes earthquake or slowly, in the form of creep. Types of faults include strike-slip faults, normal faults, reverse faults, thrust faults, and oblique-slip faults**.** It can be small and large complex interconnection fault systems and can replace one type of fault in one location with another type in another. Many faults are associated with folds. Faults are separated, bifurcated, converge, or move away from distances, sometimes creating complex fracture systems. The relative motion of faults (one side to the other) is described in terms of relationship of a hanging wall and foot wall. A foot wall is a block under a fault with a sloping fault plane.

4.5. Normal Faults

A normal fault appears to be that the suspended wall moves downward relative to the foot wall. The dip angle of the sliding surface is between 45 and 90 degrees. Many normal faults in mountainous regions are caused by gravity along the edges of the mountains and may be associated with elevation of the head wall of the slums.

4.5.1. Reverse Faults

A reverse fault**,** in which the hanging wall moves upward relative to the foot wall.

4.5.2. Strike-Slip Fault

A strike-slip fault is a generally vertical fault where the two sides pass horizontally past each other. If the block opposite an observer facing the fault moves to the right, the shift style is called “right lateral”. If the block moves to the left, the movement is called “left lateral”. The San Andreas Fault in California is the most famous example of a right lateral impact-slip fault. It produces a variety of floor shapes including pulse shifts, louver ridges, detachable basins, overhanging pools and deflected streams.

4.5.3. Thrust Fault

A thrust fault is a dip angle of 45º or less to the extent that the suspended wall appears to move upward relative to the foot wall. Horizontal compression or rotation shift is responsible for displacement.

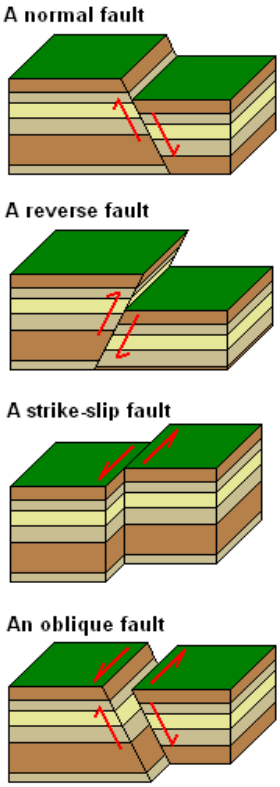

Figure 11 Different types of faults

4.6. Properties of Aquifers

4.6.1. What is Aquifer?

An aquifer is a geologic unit that can store and transmit water at rates fast enough to supply reasonable amounts to wells.

4.6.2. Types of Aquifers

Unconfined Aquifer (Water-Table Aquifer)

An aquifer that is close to the ground surface, with continuous layers of materials of high intrinsic permeability extending from the land surface to the base of the aquifer.

Recharge from downward seepage through the unsaturated zone, lateral ground water flow, or upward seepage from underlying strata.

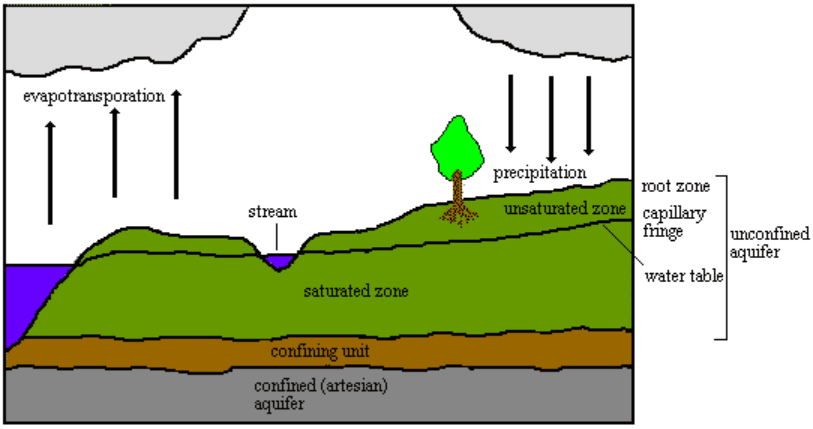

Figure 12 Unconfined aquifer

Confined Aquifer (Artesian Aquifer)

An aquifer that are overlain by a confining layer. Recharge occurs in recharge area, where the aquifer crops out, or by slow downward leakage through a leaky confining layer.
Potentiometric surface is the surface representative of the level to which water will rise in a well cased to the aquifer.

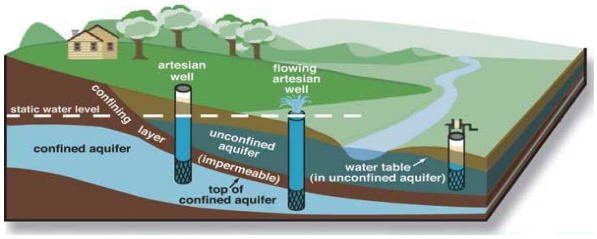

Figure 13 Confined Bed Rock Aquifer

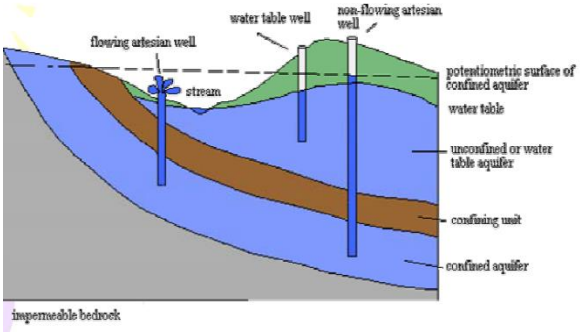

Figure 14 Impermeable Bed Rock

4.6.3. Porosity of Sedimentary Rocks

Porosity of sedimentary rocks depends on the basic of primary and secondary porosity to understand the occurrence of fluid flow behavior through matrix grain (gravels).

Primary Porosity

Primary porosity occurs in which the pores between grains of the reservoir are neglected.

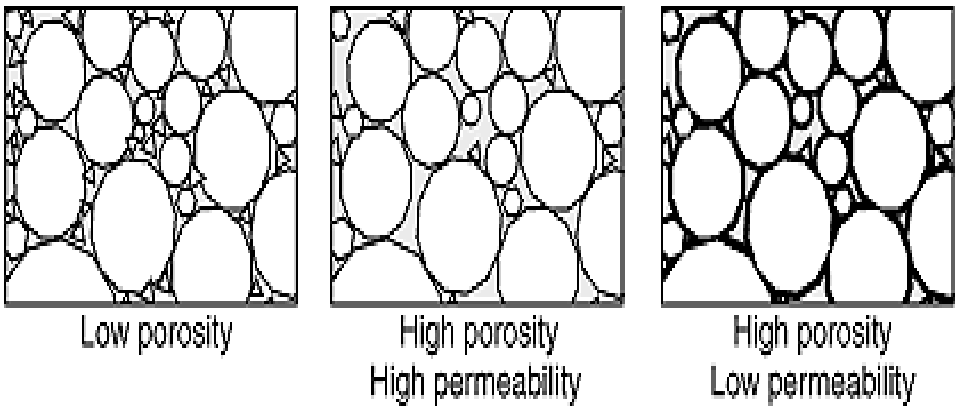

Figure 15 Primary porosity

Secondary Porosity

Secondary porosity refers to the fracture of the limestone so that the viscosity of the fluid will be considered.

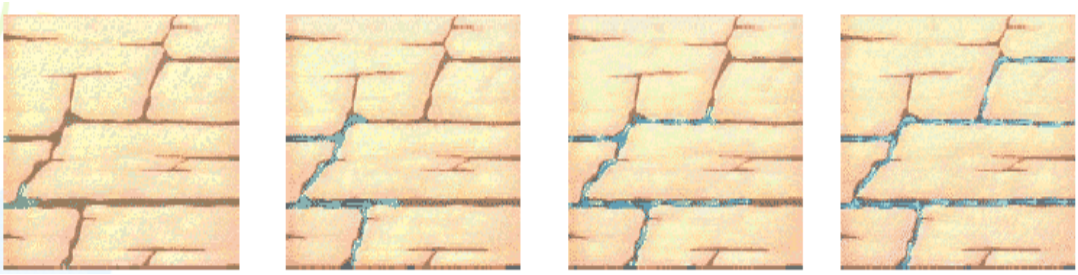

Figure 16 Secondary porosity

4.6.4. Heterogeneity and isotropy

Isotropy reservoir

Isotropic formation is a type of formation whose rock properties are the same in all directions. Although this never actually occurs, fluid flow in rocks approximates this situation closely enough to consider certain formations isotropic.

Isotropy is uniformity in all orientations; it is derived from the Greek *isos* (ἴσος, "equal") and tropos (τρόπος, "way"). Precise definitions depend on the subject area. Exceptions, or inequalities, are frequently indicated by the prefix *and*, hence anisotropy. *Anisotropy* is also used to describe situations where properties vary systematically, dependent on direction. Isotropic radiation has the same intensity regardless of the direction of measurement, and an isotropic field exerts the same action regardless of how the test particle is oriented.

Anisotropy reservoir

Anisotropy is most easily observed in single crystals of solid elements or compounds, in which atoms, ions, or molecules are arranged in regular lattices. In contrast, the random distribution of particles in liquids, and especially in gases, causes them rarely, if ever, to be anisotropic.

Anisotropic materials show different properties in different directions. Glass, crystals with cubic symmetry, diamonds, and metals are examples of isotropic materials. Wood, composite materials, all crystals (except cubic crystal) are examples of anisotropic materials. Anisotropy is defined as variations of properties with respect to the directions concerned in design and analysis of rock structures. Concept of anisotropy is well-known in the field of rock mechanics and engineering.

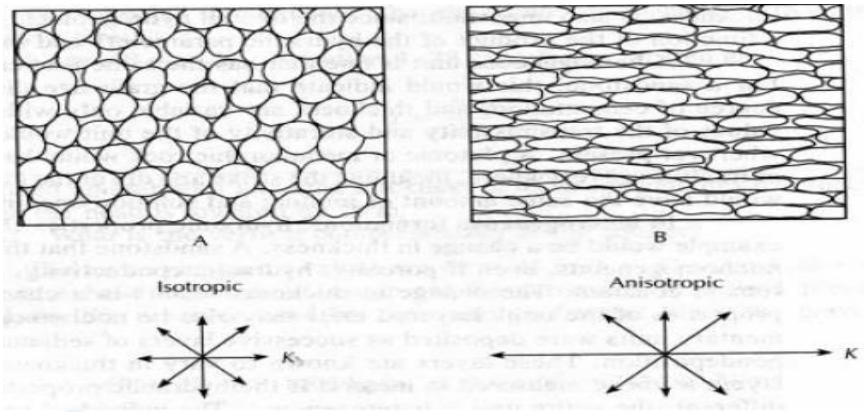

Figure 17 An insight of (A)Isotropy and (B)Anisotropy

Transmissivity

Amount of water that can be transmitted horizontally through a unit width by the full saturated thickness of the aquifer under a hydraulic gradient of 1. To determine Transmissivity of any fluid occurs with below formulae:

$$\mathbf{T = KB}$$

Where, T is Transmissivity (L^2 or m^2/d)

K is hydraulic conductivity (L/T)

B is saturated thickness of the aquifer (L or m)

4.7. Upscaling static properties

Reservoir properties often need to be up-scaled if the geological static model is built on a finer scale in terms of cell size than is intended for the simulation model. This property Upscaling should be done after the 3D-reservoir simulation grid has been constructed.

Upscaling, or homogenization, is substituting a heterogeneous property region consisting of fine grid cells with an equivalent homogeneous region made up of a single coarse-grid cell with an effective property value. (Equivalent in this case means either volume or flux vice, depending on the type of property that is to be up scaled.)Upscaling is performed for each of the cells in the coarse grid and for each of the grid properties needed in the reservoir flow-simulation model. Therefore, the Upscaling process is essentially an averaging procedure in which the static and dynamic characteristics of a fine-scale model are to be approximated by that of a coarse-scale model. A conceptual illustration of the Upscaling process is shown in figure 18.

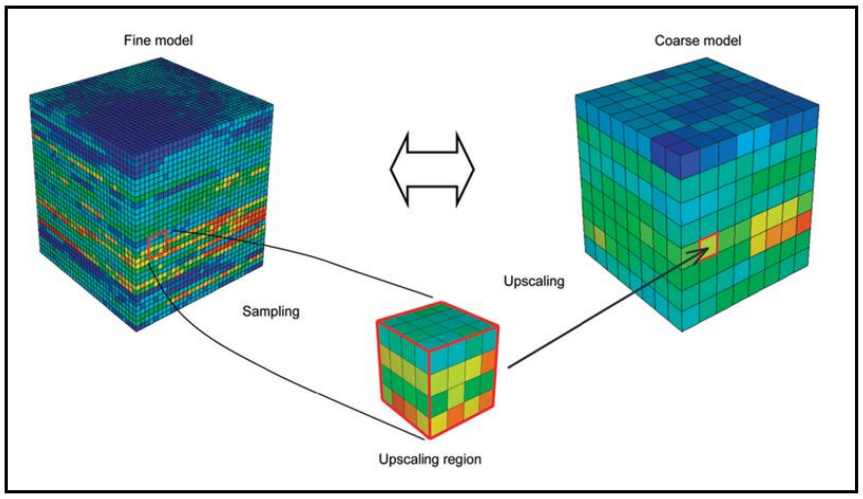

Figure 18 Concept of Upscaling

Porosity and Net-to cross

The up-scaled porosity and NTG should preserve the pore volume of the underlying geological model. In this case the bulk-volume weighted averages give the correct porosity.

Saturation

The up-scaled saturations should preserve the volume of each phase in the volume associated with each grid-block. In this case pore-volume-weighted averaging will give the correct result.

Saturation is defined as the fraction (or percentage) of the pore volume occupied by a particular fluid (oil, gas and water). The symbol for saturation is (*S*) and expressed as the following:

Fluid Saturation S = Total volume of occupied fluid pore volume

Applying this equation for different reservoir fluids:

For oil, Oil Saturation S_o =Volume of oil Pore volume

gas, Gas Saturation S_g =Volume of gas Pore volume

water, Water Saturation S_w =Volume of water Pore volume

Permeability

As a flow property, permeability should be defined as a diagonal tensor and up-scaled by using flow based up-scaling techniques. Tensor Upscaling can be time consuming for large / complicated models, and scalar Upscaling is often employed. It can be verified if arithmetic-harmonic (horizontal and vertical permeability) Upscaling yields a reservoir simulation model with reasonable behavior and similar to that with tensor Upscaling, which in some cases tends to underestimate vertical communication and is therefore trickier to use. Types of permeabilities are:

Absolute Permeability (k)

When the medium is completely saturated with one fluid, the permeability of the formation is referred to specific or absolute permeability.

Effective Permeability (k_e)

When the rock pore spaces contain more than one fluid, the permeability to a particular fluid is called the effective permeability. Effective permeability is a measure of the fluid conductance capacity of a porous medium to a particular fluid when the medium is saturated with more than one fluid. Effective permeability is less than absolute permeability because the presence of a second fluid reduces the effective pore diameter available for fluid flow.

Relative permeability

Relative permeability is defined as the ratio of the effective permeability of a specific fluid at a given saturation to absolute permeability. It is dimensionless.

For Oil, $k_{ro} = k_{eo}/k$

Water, $k_{rw} = k_{ew}/k$

Gas, $k_{rg} = k_{eg}/k$

Relative permeability curves reflect the capacity of the rock to produce given fluids by showing the permeability of those fluids as a function of saturation.

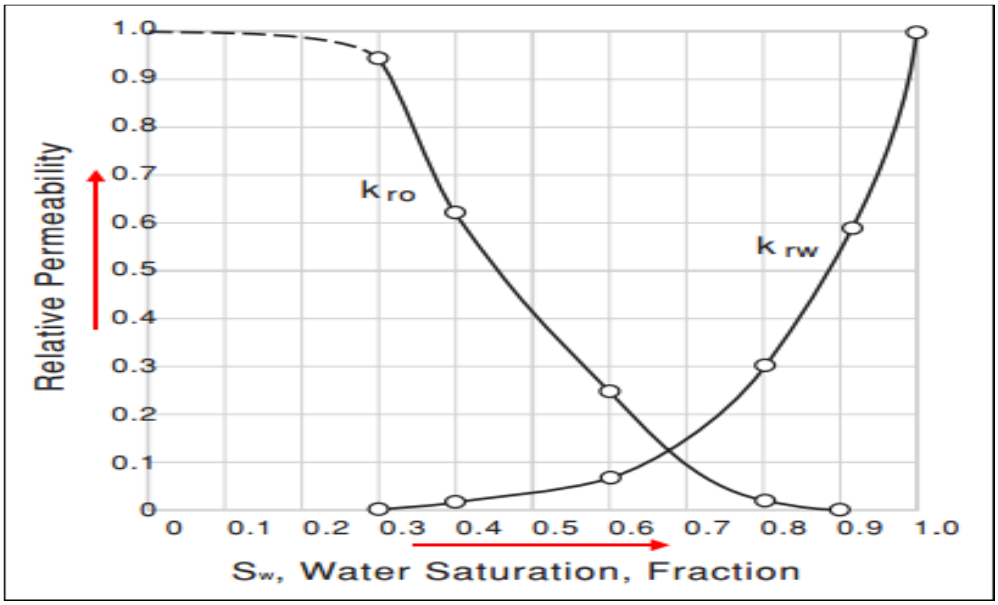

Figure 19 Diagram of relative permeability

4.7.1. Upscaling techniques for absolute permeability

Homogenization of absolute permeability does not have an exact analytical solution, except for in a few idealized cases. The challenge of computing an accurate effective permeability has resulted in a large number of Upscaling techniques. These techniques range from simple statistical averages to advanced numerical methods. Tensor methods are the most accurate techniques available for computing the effective cell permeability. These are based on solving a second-order elliptic differential equation describing single-phase, incompressible, steady-state fluid flow in a region without sources and sinks (i.e., wells). Some flow-based methods may provide a *full* permeability tensor. The flow equation is usually discretized with a finite-difference scheme, although finite-element methods are also applied occasionally. To compute all the directional components of the permeability tensor, the discretization and solution of the flow equation must be performed for each of the principal flow directions (i.e., three separate single-phase simulations need to be performed). Each simulation involves the iterative solution of a linear equation system (typically, the linear solver is a conjugate gradient

method, preconditioned by incomplete Cholesky or LU factorization). The unknowns in this equation system are the geo-cell pressures inside the flow cell, whereas known quantities are the geo-cell dimensions and permeabilities, as well as the pressure conditions along the faces of the flow cell. When the numerical solution of the fine-scale pressure distribution has converged, an effective permeability is computed by equating expressions for the flux through the heterogeneous geo cells with the flux through the equivalent homogeneous flow cell using some form of Darcy's law.

4.7.2. Upscaling schemes for absolute permeability

Based on the size of the computational region, the single-phase Upscaling process may either be described as local, regional, or global. With local Upscaling techniques, the computational region is identical to the Upscaling region (i.e., only geo cells inside the flow cell are considered in the Upscaling computations). For regional Upscaling, the computational region is expanded beyond that of the flow cell to include a buffer region of neighboring geo cells. In the case of global Upscaling, the computational region is that of the entire geo model. The following figure shows how the computational region varies with the different Upscaling schemes.

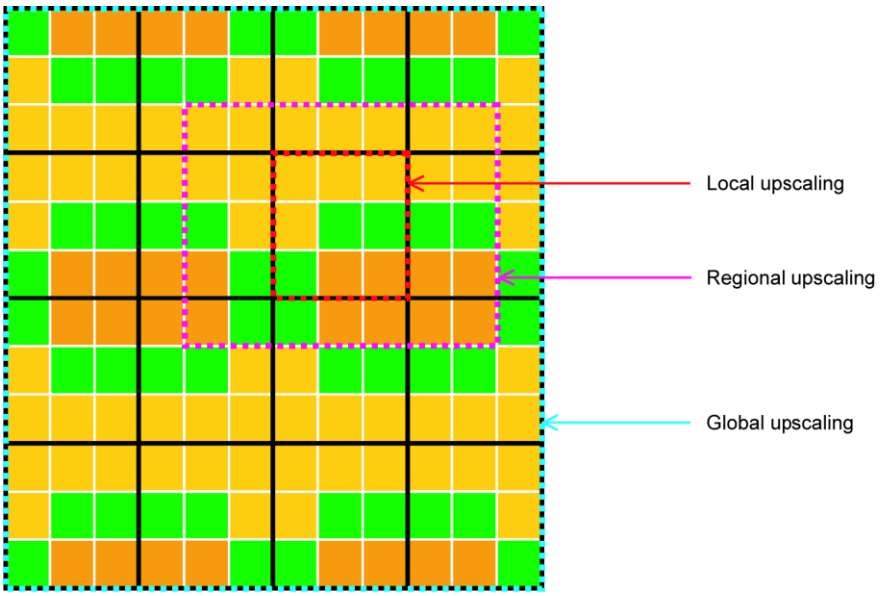

Figure 20 Upscaling schemes and the size of the computational region (Geo grid in white and flow grid in black)

It should be noted that the different Upscaling schemes are only relevant when considering flow-based (tensor) methods. It is also important to realize that even though the computational region may vary according to the scheme used, the Upscaling region remains

unchanged and is of course defined by the flow cell, as in the case of the simple, analytical Upscaling techniques.

4.7.3. Local Upscaling

Because it used to be too time-consuming to compute the fine-scale pressure field for the complete geo grid in a single operation, the flow-based methods have traditionally been restricted to solving the pressure field locally that is, for a single flow cell at a time. Hence, the effective cell permeability is computed separately and independently of the other flow cells, which may or may not be correct depending on how representative the imposed pressure conditions along the faces of the flow cell are. Different types of artificial boundary conditions for the flow cell have been suggested over the years, all with the objective of providing as good an approximation of the real boundary conditions as possible. An important design criterion for the artificial boundary conditions is the conservation of flux in and out of the flow cell. The first type of boundary conditions proposed for the local solution of the pressure equation was published by Warren and Price in 1961.

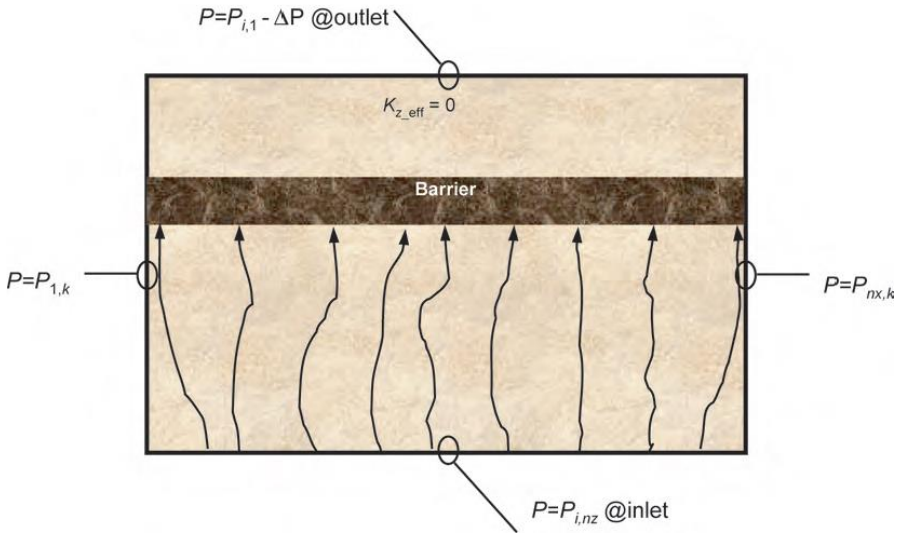

Figure 21 The sealed sides boundary condition (in z-direction)

Their approach is to impose a constant pressure gradient in a selected direction of flow by specifying a pressure of 1 on the inflow face and a pressure of 0 on the outflow face. By allowing no flow to pass through the sides of the cell, all fluxes are forced to go in the principal direction of flow. Therefore, this type of boundary conditions is often referred to as the no-flow or sealed-sides boundary conditions. The sealed-sides boundary conditions are graphically illustrated above fig 21. for flow in the vertical direction (here in the case of a flow cell containing a barrier). The choice of boundary conditions emulates the way core

permeability is measured in the lab. This is hardly a coincidence. As in the core flood experiment, the local numerical flow simulation is in effect 1D because the cell faces parallel to the main flow direction are sealed. This implies that the estimated effective permeability will be scalar. Hence, the maximum number of directional permeability components that can be obtained with this type of boundary conditions is three, one for each of the principal directions of flow. In practice, the diagonal permeability tensor is derived by setting up the boundary conditions for *x*, *y*, and *z* directions, respectively, in three independent single-phase simulations.

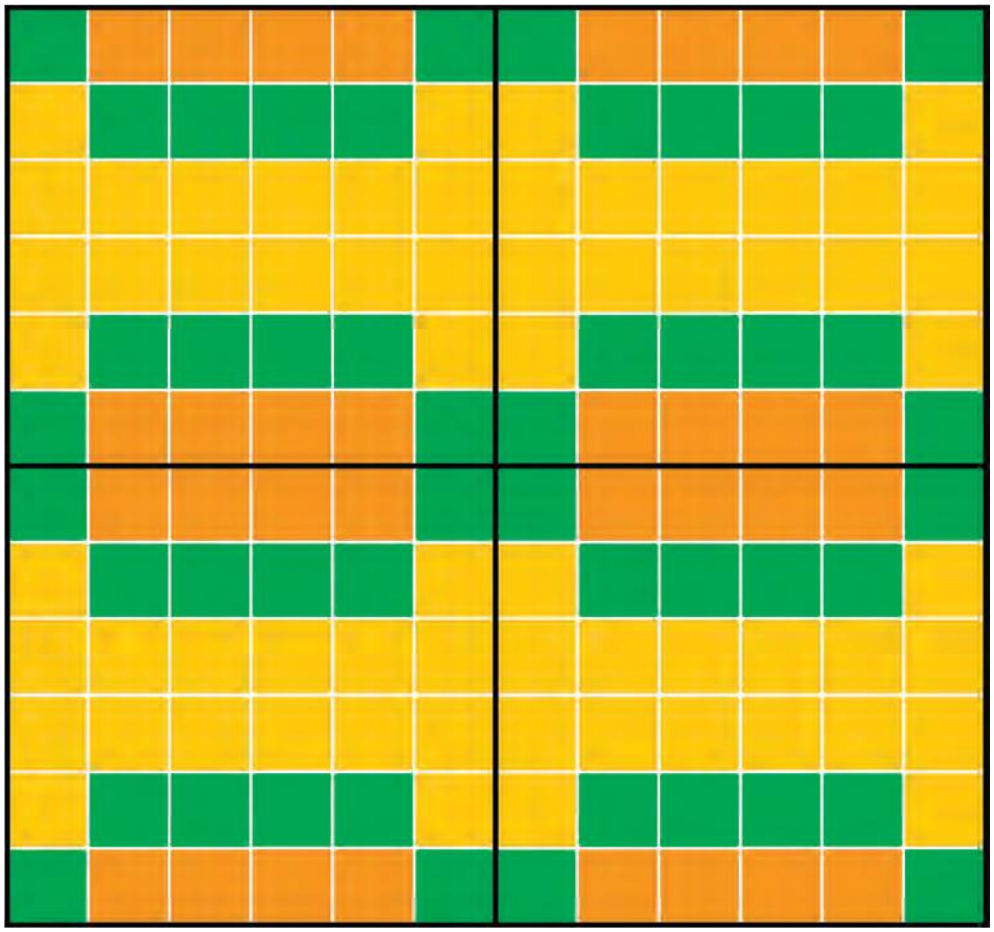

Figure 22 The fine-scale permeabilities are symmetric on the scale of the flow cell (geo grid in white,flow grid in black)

Strictly speaking, the sealed-sides boundary conditions are only valid if no wells are present and the flow cells are symmetric in each direction of the grid as illustrated in 2D with fig 22. Hence, the sealed-sides boundary conditions assume that the flow cell is surrounded by mirror images of itself. By the end of the 1980s, 3D geological models had started to appear more regularly on the modeling scene. This resulted in a new demand for advanced Upscaling. In this renewed effort, two alternative boundary conditions for solving

the local pressure solution in a flow-based method were suggested more or less at the same time. One was based on linear boundary conditions, the other on periodic boundary conditions.

The use of linear boundary conditions in flow-based Upscaling was suggested by Guerillot *et al*. In 1989 and Seamier in 1990 to enable the computation of a full-permeability tensor. Instead of setting the flow through the sides of the cell to zero, the pressure along the sides is allowed to vary in a linear fashion that matches the constant pressure on the two cell faces perpendicular to the flow. Hence, the imposed pressure gradient is still constant, but the flow is allowed to enter and leave the cell at any point along the sides parallel to the main flow direction.

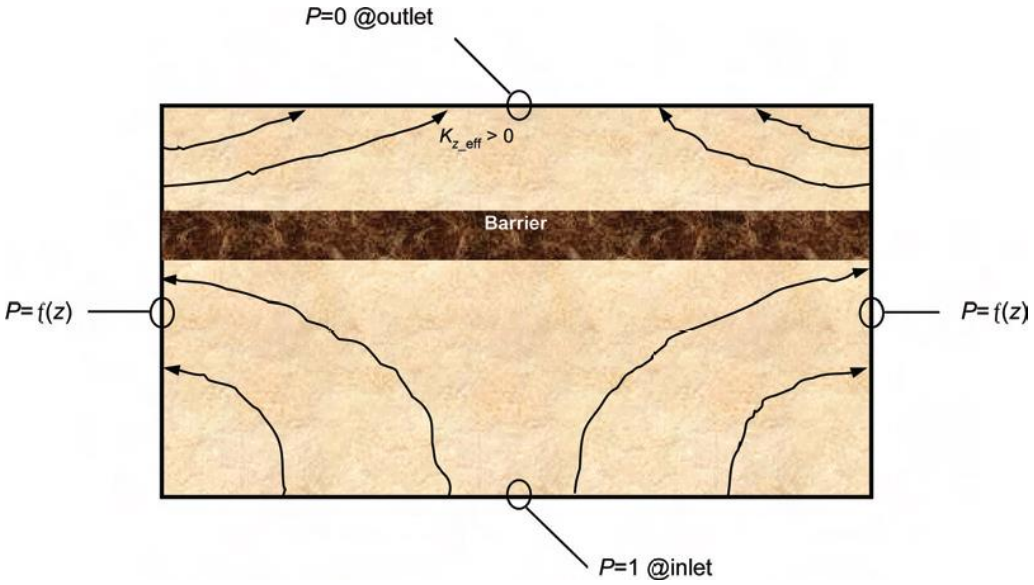

Figure 23 The open sides boundary condition (In z-direction)

As with the sealed-sides boundary conditions, three independent single-phase simulations, with the main flow direction in *x*, *y*, and *z*, respectively, are needed to yield all of the components of the permeability tensor. With open-sides boundary conditions, however, also the off-diagonal components will generally be nonzero. Hence, unlike the sealed-sides boundary conditions where the effective permeability is limited to that of a diagonal tensor, the open-sides boundary conditions, as previously mentioned, give a full permeability tensor. The resulting full tensor may be either symmetric or nonsymmetrical depending on the properties of the method under consideration. As documented in two different sources, a tensor technique based on the open-sides boundary conditions tends to bias the estimated effective permeability toward a high value. The physical implication of this is most clearly seen in the case of a bimodal permeability system of sand and shale. This is because the open-sides method

consistently overestimates the reservoir flow characteristics by narrowing shale barriers and thickening sand channels. The latter effect also has a tendency of connecting isolated sand channels. Take, for example, the situation illustrated by Fig 23. Even though the barrier extends across the entire length of the local Upscaling region, the resulting effective permeability (in the *z*-direction) will be significantly larger than zero. For vertical flow, the result is therefore a narrowing of the shale in the flow model equal to the horizontal dimensions of the flow cell. Depending on which factors affect fluid flow in the region of the cell, this may or may not be a representative value for that particular flow cell. The use of linear boundary conditions has its origin in the effective medium theory, which states that any region of permeability behaves as if embedded within the average medium. Strictly speaking, these boundary conditions are therefore only valid if the neighboring flow cells are of a uniform, nonzero permeability. This is illustrated in 2D by fig 24.

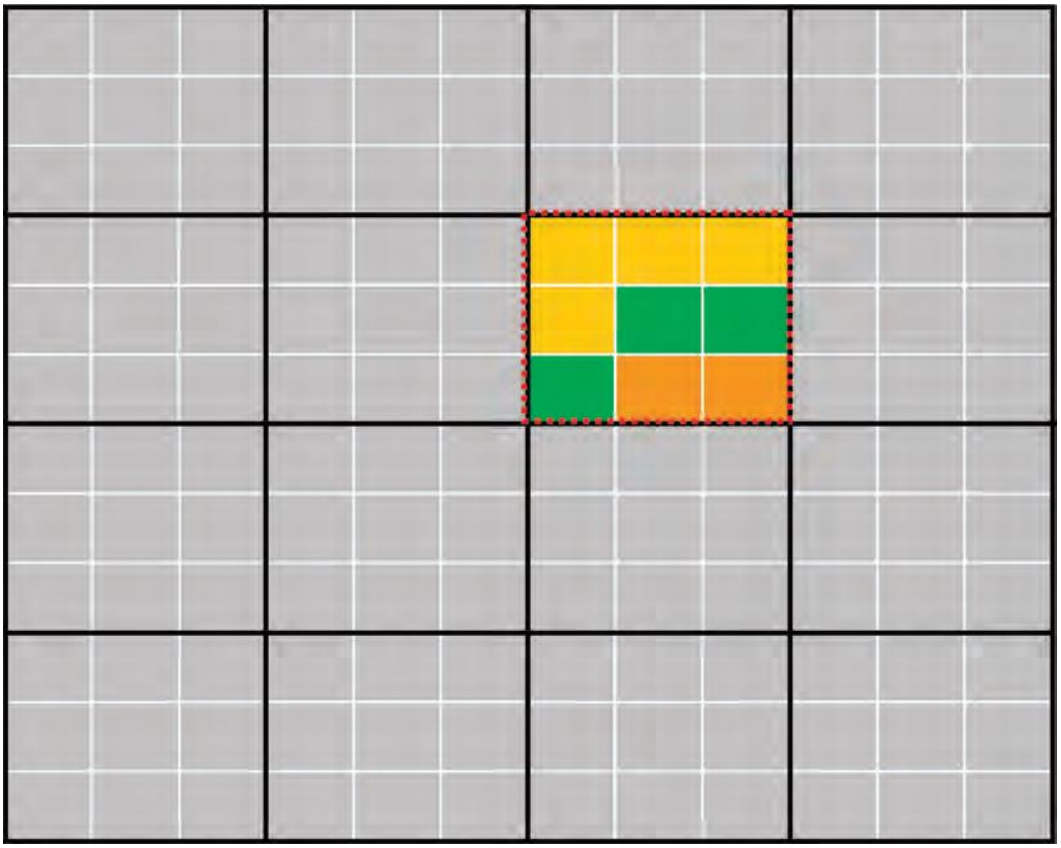

Figure 24 The fine-scale properties are uniform and nonzero outside the Upscaling region (the geo cells outside the Upscaling region are drawn in gray to reflect that the average value need not be known)

4.7.4. Regional Upscaling

Regional Upscaling is applied to reduce the influence of the artificial boundary conditions on the effective permeability estimate by moving the boundary of the computational

region away from the flow cell. This implies that the influence of neighboring geo cells is taken into account in addition to the geo cells inside the flow cell. In other words, regional Upscaling represents an expansion of the local computational region outside the volume of the flow cell. The size of the so-called buffer or skin around each flow cell is usually given in number of neighboring geo cells to either side of the flow cell and must be specified by the modeler for each of the three coordinate directions. The permeability estimate of a regional Upscaling method will improve as the size of the buffer region increases, and it will ultimately be equal to the "true" effective permeability when the buffer size has reached the boundaries of the geo model for all three directions. The gain in accuracy is largest in the beginning (i.e., for small buffer values). This is illustrated by Fig 25, showing the behavior of the lower- and upper-bound tensor techniques in the case of increasing buffer size. Please note that in Fig 25, the outer bounds are shown to be symmetric around the "true" effective permeability. Generally, this is not the case.

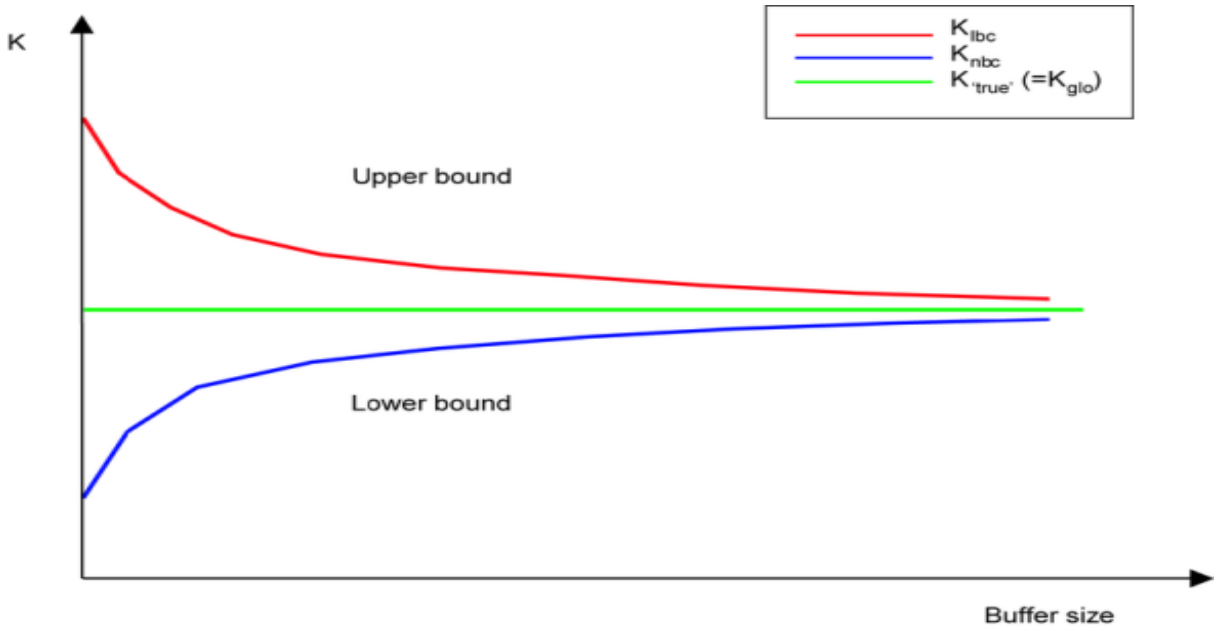

Figure 25 The outer bounds of effective permeability and their behavior with increasing buffer size

5. RESERVOIR ROCK AND FLUID PROPERTIES

5.1. Rock compressibility

Rock compressibility is one of the most important input parameters for initialization of any reservoir simulation study. This parameter should be based on core analysis and rock mechanics studies.

It is recommended not to change this parameter during the history matching process, if possible. If modified, it should be checked with the team members representing the rock mechanics discipline. This needs to be done to ensure that final rock compressibility applied in the model has a physical meaning.

5.2. Fluid PVT Data

The two most common types of reservoir fluid models are black-oil models and compositional models. The black-oil models are based on the assumptions that the saturated phase properties of two hydrocarbon phases (oil and gas) depend on pressure only.

Compositional models also assume two hydrocarbon phases, but they allow the definition of many hydrocarbon components. The time cost of running a compositional simulator increases dramatically with an increase in the number of components modeled, but the additional components make it possible to more accurately model complex fluid phase behavior. If compositional model results are to be used in a process engineering model, it is often necessary to compromise on the number of components to be used for each application.

The typical fluid PVT properties used in reservoir simulation study are: formation volume factor, viscosity, and solution gas-oil-ratio and water compressibility.

5.3. Relative permeability

Relative permeability curves represent flow mechanisms, such as drainage or imbibition processes, or fluid wettability. Relative permeability data should be obtained by experiments that best model the type of displacement processes in the reservoirs. For example, water/oil imbibition curves are representative of water flooding, while water/oil drainage curves describe the movement of oil into a water zone. The modeling team should recognize that the relative permeability curves used in a flow model may be very dependent on the

experiment that was used to measure the curves. Applying these curves to another type of displacement mechanism can introduce significant error.

5.4. Capillary pressure

Capillary pressure is usually included in reservoir simulation studies. The relationship between capillary pressure and elevation is used to establish the initial transition zone in the reservoir. The oil/water transition zone, for example, is the zone between water-only flow and oil-only flow. It represents the part of the reservoir where 100% water saturation grades into oil saturation with irreducible water saturation. Similar zones may exist at the interface between other pairs of immiscible phases.

Capillary pressure data is primarily used for determining initial fluid contacts and transition zones. If petro physical evaluation and property modeling concludes that there is a relative thick transition zone, then capillary pressure should be used; however, if the transition zone is considered to be negligible, then no major benefit can be expected from the use of capillary pressure data.

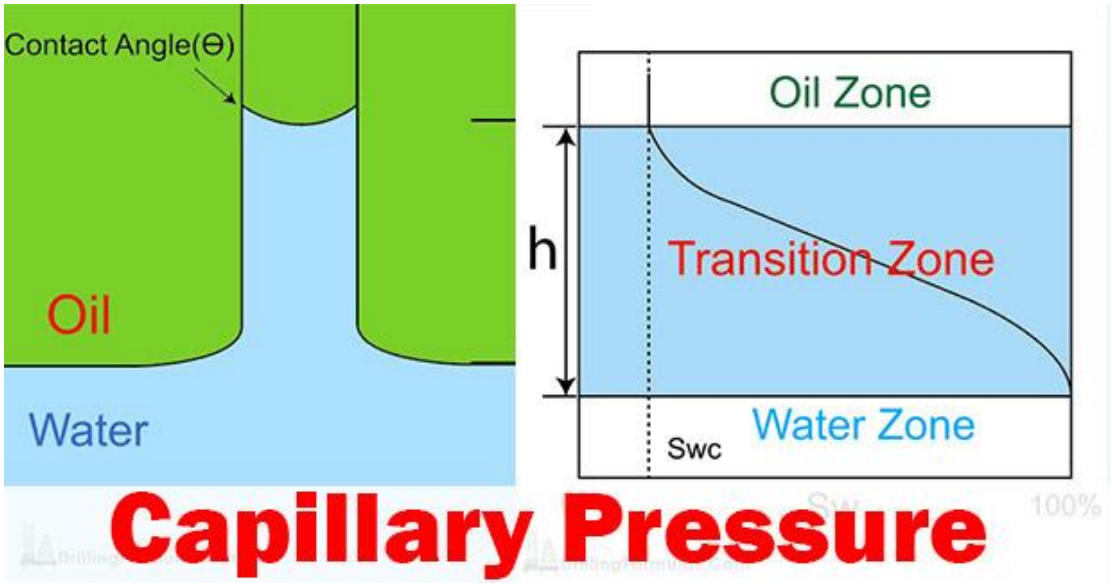

Figure 26 Capillary pressure diagram

Reservoir rocks are composed of many capillaries of varying sizes. Capillary pressure is the phenomenon by which water or any wetting liquid is drawn up into a capillary. The smaller the capillary (diameter), the higher the liquid rises.

In a reservoir that contains water (bottom) and oil (top) the demarcation between the two is not always sharp. There is a more or less gradual transition from water table to mostly oil named transition zone (interval). The transition zone is the zone which displays a change in

the water saturation with height. If the oil-bearing interval is thick enough, water saturation at the top approaches a minimum value (connate or irreducible water saturation) above transition zone. All water with 100% water saturation which is below the transition zone also called water table or free water level (FWL).

6. DYNAMIC PROPERTIES AND WELL DATA

Dynamic properties and well data are primarily required for the following:

- Reservoir simulation model quality control
- History matching process
- Predictions.

6.1. Historical production / injection and pressure data

The typical historical data used in reservoir simulation models includes the following:

- Oil, water and gas rates
- Water and/or gas injection rates
- Measured shut-in pressures
- Water-cut
- Repeat formation tester (RFT)/production log tool (PLT) data
- Saturation data.

The historical well tubing head pressure, well bottom hole pressure, well productivity index (PI), and well flow performance tables are required to calibrate reservoir simulation models when reservoir simulation models are used for predictions (in other words, when the wells are changed from volume control to pressure control).

The history matching stage of a numerical reservoir simulation model might be in some cases of complex models more difficult and time consuming than expected, to achieve an acceptable match requires knowledge of the reservoir architecture, the geology, the driving mechanisms, and the physics of the reservoir simulators; even more, historically there had been cases of reservoir simulation models that been disqualified and discharged as a result of the inability to achieved an acceptable history match.

We have faced some of these cases, where the history match was not achieved and the static model was challenged and disqualified, there our experts succeeded with a systematic review of all its components ending with history matched model which avoided the need to rebuild an expensive new model.

6.1.1. History matching:

The main objective of the history match is to achieve a reasonable agreement between the simulated and observed historical field/well behavior to establish a satisfactory quality reservoir management tool. This is done under the premises that the geological model, the reservoir parameters, and other static and dynamic data used have a “defendable” quality.

6.1.2. Manuel vs. assisted history matching:

Two approaches can be applied for performing history matching study: manual history matching and assisted history matching using specialized software. Traditionally, history matching is performed by a trial-and-error approach. In this case, a lot of manual tasks are involved, such as changing the reservoir simulation model, running reservoir simulations, plotting curves and comparing to observed data. The main advantage of assisted history matching is to automate those manual tasks, such as reservoir simulation model modifications, running reservoir simulations, comparison of observed and reservoir simulation data, etc. however care should be taken in setting parameter range limits, etc. in automated history match to ensure any solutions are physically valid.

6.1.3. History matching input data:

The following historical (measured) input data for individual wells or reservoirs are typically used in history matching process:

- RFT pressures (measured pressure points vs. depth)
- Shut-in pressure (measured pressure vs time)
- Historical production / injection rates vs. time
- Allocated or measured well GOR and WCT vs. time
- Fluid saturation profiles from well logs

6.2. Well Data

The well data (trajectory and perforation intervals) are required to assign well perforation intervals to the reservoir simulation grid and simulate well performance. The using of software will help us to design the logs as sonic, resistivity, porosity (neutral, caliper log) etc.

6.2.1. Material balance

An alternative, largely independent method of estimating the original hydrocarbons in-place (OOIP and OGIP).

The material balance equation (MBE) is a powerful reservoir engineering tool, which is used for evaluation of the initial gas-in-place (IGIP) and prediction of the production performance of the gas reservoirs.

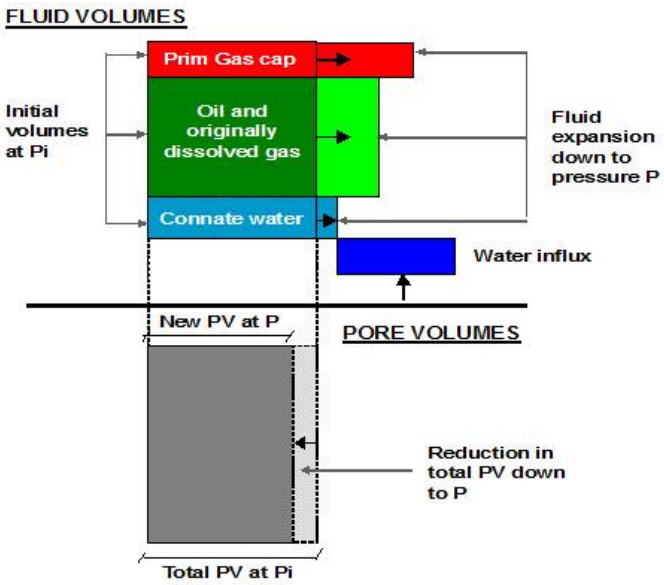

Figure 27 Material Balance Diagram

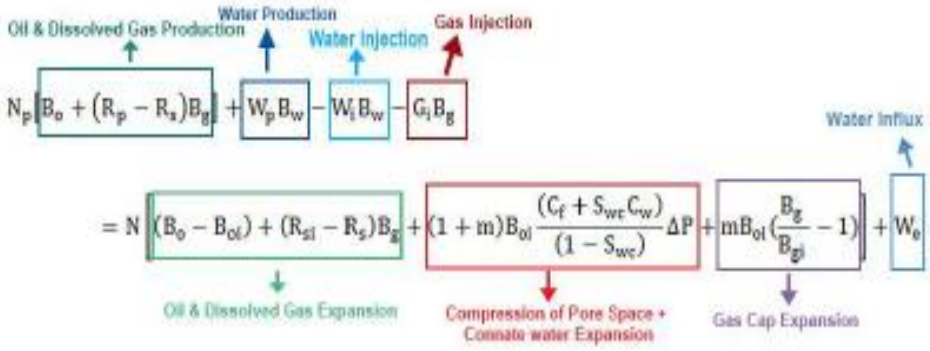

Figure 28 Material Balance Equation

Where,

N_p = Cumulative (Produced gas, oil and water), L^3 , STB

B_o = Oil formation volume factor, RB/STB

R_p = Dissolved gas produced GOR, SCF

R_s = Dissolved gas solution GOR, SCF

B_g = Gas formation volume factor, RB/SCF

W_p = Cumulative produced water,L^3,STB

B_w = Water formation volume factor, STB

W_i = Cumulative water injection, L^3, STB

G_i = Cumulative gas injection, L^3, SCF

R_{si} = Initial dissolved gas GOR, SCF

B_{oi} = Initial oil formation volume factor, RB/STB

B_{gi} = Initial gas formation volume factor, RB/SCF

S_{wc} = Connate water saturation, L^3, STB

m = Mass, kg/m^3

C_f = Rock compressibility factor, Lt^2/m, 1psi

C_w = Water compressibility factor, L^2/m, 1psi

ΔP = Pressure drop, psi

7. RESERVOIR SIMULATION MODEL INITIALIZATION AND VALIDATION

7.1. Reservoir Simulation Model Initialization

To initialize a reservoir simulation model, the initial oil, gas and water pressure distribution and initial saturations must be defined in the reservoir model. Pressure data are usually referenced to some datum depth. It is convenient to specify a pressure and saturation at the datum depth and then to calculate phase pressures based on fluid densities and depths. The initialization of the reservoir simulation models is the process where the reservoir simulation model is reviewed to make sure that all input data and volumetric are internally consistent with those in the geo-model. The reservoir simulation model should normally be in dynamic equilibrium at the start of production, but there might be some exceptions to that rule. Non-equilibrium at initial conditions may imply some data error or the need to introduce pressure barriers (thresholds) between equilibrium regions.

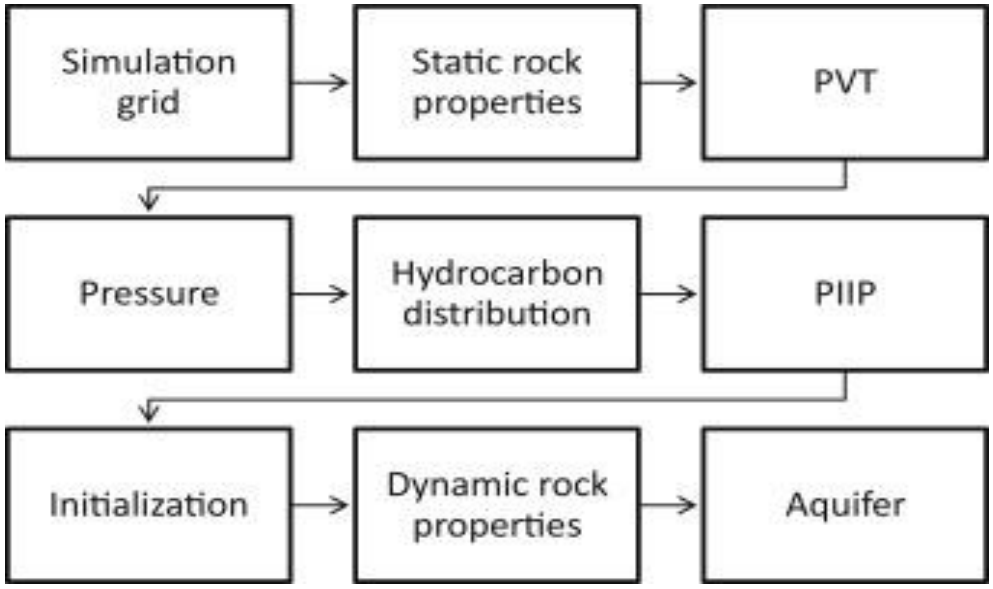

Figure 29 Workflow chart of model initialization

The construction and initialization of detailed large simulation models, however, entails working with a voluminous amount of data that can easily become inconsistent. This project will also presents the methods and procedures that have been successfully established for initializing such models in which both detail and consistency are preserved.

7.2. Reservoir simulation model validation

At this step, the main objective is to verify that the reservoir simulation model accurately represents the structure and properties in the geologic model. The following validation steps are recommended:

- Visualize reservoir simulation grid, each grid layer and each cross-section, to ensure that simulation grid is constructed correctly and all grid blocks are suitable for reservoir simulations.
- Compare reservoir simulation grid with the geological grid and make sure that reservoir simulation grid layers and fault geometries are consistent with the structural depth maps used.
- Visualize and compare reservoir simulation model properties (porosity, permeability, net-to-gross ration and fluid saturation) with those in the geological model.
- Compare reservoir simulation model gross-rock-volume, pore volume, and hydrocarbon in-place volumes with the geological model volumes
- Verify that the wells are consistently represented in the reservoir simulation grid.

8. RESERVOIR SIMULATION MODEL PREDICTION CAPABILITY

8.1. Simulation Model Prediction

The reservoir simulation model-building process and history matching are intended to provide a working model of the reservoir and establish a level of confidence in the validity of a flow model. Therefore, the final history matched model is usually re-configured to predict the behavior of the reservoir into the future.

When a reservoir simulation model is changed from history matching to prediction mode, the phase rate profiles should be smooth, provided new wells are not added or existing wells shut-in, and the fundamental constraints on the wells are not changed. There should not be a shift up or down in rates at this point. Such a shift is usually indicative of non-calibrated wells.

It is recommended that the last year of history is run in prediction mode and the actual production compared with the simulated prediction. While this should not be expected to give a perfect match, it will help to highlight major discrepancies in the model.

When a reservoir simulation model is used for predictions, the limitations and uncertainties involved in the reservoir simulation models should be recognized. If the geological model, for example, is not reasonable and observed data quality is poor, not much quality can be expected from reservoir simulation model, no matter the quality of the history match.

Pattern recognition capabilities of Artificial Intelligence & Data Mining (AI&DM) can play many different roles in assisting engineers and geoscientists in building reservoir simulation models. The objective of this article is to introduce a set of comprehensive and complete workflows that have been developed based on the AI&DM for building full field reservoir simulation models. Two of these workflows will be covered in this article. Complete and detail (step by step) procedure for developing these models requires multiple manuscripts (some of which are referenced here) and cannot be included in one paper. Therefore, this article is intended to serve as an introduction to the technology and will be followed by more details manuscripts. In order to put these new AI-based workflows in perspective and for the purposes of this article, let us summarize reservoir simulation and modeling as a process that ultimately

models production from a field (of multiple wells) as a function of reservoir and fluid characteristics, operational constraints and other variables in the following formulation:

$$Q = f\ (X_1, X_2, \ldots\ldots., X_n\ \&\ Y_1, Y_2, \ldots\ldots\ Y_n\ \&\ W_1, W_2, \ldots\ldots.\ W_n)$$

where q is the production from the reservoir; x_1, x_2, …., x_n, reservoir and fluid characteristics; y_1, y_2, …., y_n, operational constraints; w_1, w_2, …., w_n, other parameters; f( ), functional relationship. The above equation simply states that production from a field is modeled using a series of functional relationships between reservoir-fluid characteristics, operational constraints (drilling new wells, injecting water, shutting some wells, changing the surface facility capacity) and other variables such as well configurations, completion techniques, etc. This formulation is applicable for both numerical reservoir simulation and AI-based modeling. In both of these modeling techniques the intent is to model production as a function of reservoir-fluid characteristics, well characteristics and operational constraints. The major difference between these two techniques appears in the philosophy of the state of our knowledge of the phenomenon (fluid flow in porous media) and the assumptions made during the modeling process.

9. CASE STUDY ON "AN APPROACH TO WATERFLOODING OPTIMIZATION"

9.1. Principle of Waterflooding

The terms primary oil recovery, secondary oil recovery, and tertiary (enhanced) Oil recovery are traditionally used to describe hydrocarbons recovered according to the method of production or the time at which they are obtained.

Primary oil recovery describes the production of hydrocarbons under the Natural driving mechanisms present in the reservoir without supplementary help from injected fluids such as gas or water. In most cases, the natural driving mechanism is a relatively inefficient process and results in a low overall oil recovery. The lack of sufficient natural drive in most reservoirs has led to the practice of supplementing the natural reservoir energy by introducing some form of artificial drive, the most basic method being the injection of gas or water.

Secondary oil recovery refers to the additional recovery that results from the Conventional methods of water injection and immiscible gas injection. Usually, the selected secondary recovery process follows the primary recovery but it can also be conducted concurrently with the primary recovery. Water flooding is perhaps the most common method of secondary recovery. However, before undertaking a secondary recovery project, it should be clearly proven that the natural recovery processes are insufficient; otherwise, there is a risk that the substantial capital investment required for a secondary recovery project may be wasted.

Tertiary (enhanced) oil recovery is that additional recovery over and above what could be recovered by primary and secondary recovery methods. Various methods of enhanced oil recovery (EOR) are essentially designed to recover oil, commonly described as residual oil, left in the reservoir after both primary and Secondary recovery methods have been exploited to their respective economic limits. Fig illustrates the concept of the three oil recovery categories.

9.2. Factors to Consider in Waterflooding

Thomas, Mahoney, and Winter (1989) pointed out that in determining the suitability of a candidate reservoir for waterflooding, the following reservoir characteristics must be considered:

- Reservoir geometry
- Fluid properties

- Reservoir depth
- Lithology and rock properties
- Fluid saturations
- Reservoir uniformity and pay continuity
- Primary reservoir driving mechanisms

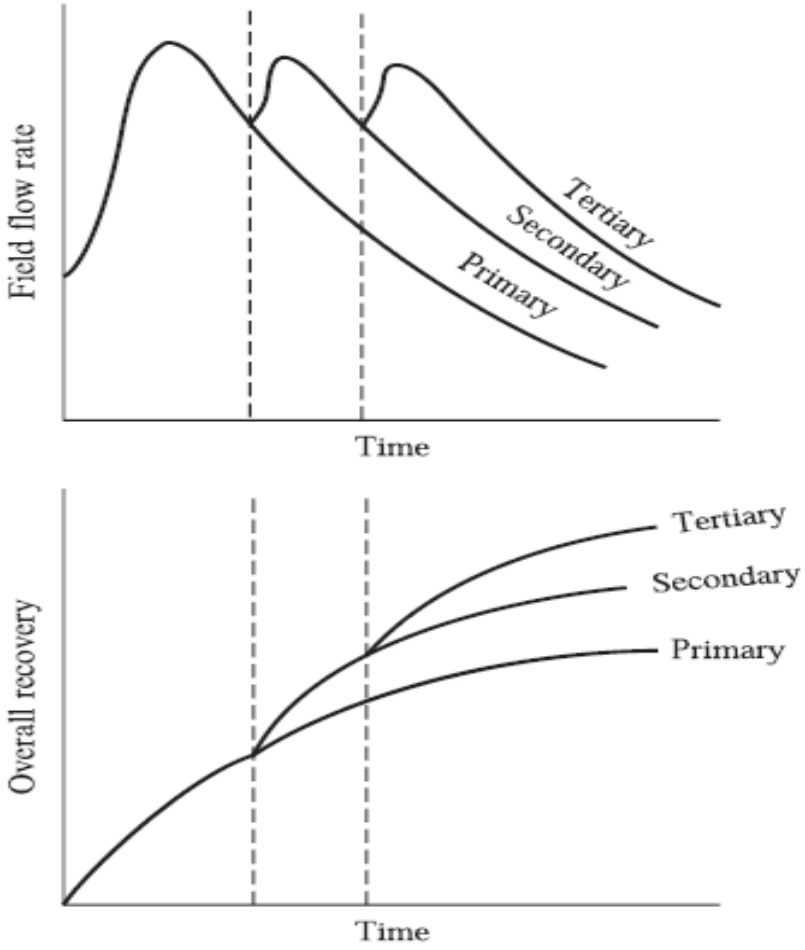

Figure 30 Oil Recovery Categories

9.3. Reservoir Geometry

The areal geometry of the reservoir will influence the location of wells and, if offshore, will influence the location and number of platforms required. The reservoir's geometry will essentially dictate the methods by which a reservoir can be produced through water-injection practices.

An analysis of reservoir geometry and past reservoir performance is often important when defining the presence and strength of a natural water drive and, thus, when defining the

need to supplement the natural injection. If a water-drive reservoir is classified as an active water drive, injection may be unnecessary.

9.4. Fluid Properties

The physical properties of the reservoir fluids have pronounced effects on the suitability of a given reservoir for further development by waterflooding. The viscosity of the crude oil "μo" is considered the most important fluid property that affects the degree of success of a waterflooding project. The oil viscosity has a significant impact of the mobility of the oil "λo" which, in turn, impact the mobility ratio "M". As discussed later in this chapter, the oil mobility is defined by the ratio:

$$\lambda_o = k_o/\mu_o$$

While the mobility ratio is defined as the ratio of the displacing fluid mobility, e.g. "λw", to that of the displaced fluid, e.g. "λo", i.e.

$$M = \lambda_o/\lambda_o$$

$$M = (K_w/K_o)(\mu_o/\mu_w)$$

The water displacing efficiency can be enhanced substantially by reducing the mobility ratio "M" by either increasing μw or decreasing μo.

9.5. Reservoir Depth

Reservoir depth has an important influence on both the technical and economic aspects of a secondary or tertiary recovery project. Maximum injection pressure will increase with depth. The costs of lifting oil from very deep wells will limit the maximum economic water–oil ratios that can be tolerated, thereby reducing the ultimate recovery factor and increasing the total project operating costs. On the other hand, a shallow reservoir imposes a restraint on the injection pressure that can be used, because this must be less than fracture pressure. In waterflood operations, there is a critical pressure (approximately 1 psi/ft of depth) that, if exceeded, permits the injecting water to expand openings along fractures or to create fractures. This results in the channeling of the injected water or the bypassing of large portions of the reservoir matrix. Consequently, an operational pressure gradient of 0.75 psi/ft of depth normally is allowed to provide a sufficient margin of safety to prevent pressure parting.

9.6. Lithology and Rock Properties

Thomas et al. (1989) pointed out that lithology has a profound influence on the efficiency of water injection in a particular reservoir. Reservoir lithology and rock properties that affect flood ability and success include:

- Porosity
- Permeability
- Clay content
- Net thickness

In some complex reservoir systems, only a small portion of the total porosity, such as fracture porosity, will have sufficient permeability to be effective in water-injection operations. In these cases, a water-injection program will have only a minor impact on the matrix porosity. Although evidence suggests that the clay minerals present in some sands may clog the pores by swelling and deflocculating when waterflooding is used, no exact data are available as to the extent to which this may occur.

Tight (low-permeability) reservoirs or reservoirs with thin net thickness possess water-injection problems in terms of the desired water-injection rate or pressure. Note that the water-injection rate and pressure are roughly related by the following expression:

$$P_{inj} < i_w/hk$$

Where:

P_{inj} = water-injection pressure

I_w = water-injection rate

h = net thickness

k = absolute permeability

The above relationship suggests that to deliver a desired daily injection rate of i_w in a tight or thin reservoir, the required injection pressure might exceed the formation fracture pressure.

It should be pointed out the reservoir heterogeneity can greatly impact and reduce the oil recovery by waterflooding. For example, the presence of sealing faults and permeability discontinuities can reduce the effectiveness of water injectors in providing sufficient pressure support to the reservoir. High permeability streaks are another type of reservoir heterogeneity that impacts the performance of the waterflood. These high permeability streaks can change the waterflood flow pattern and might result in an early water breakthrough.

9.7. Fluid Saturation

In determining the suitability of a reservoir for a waterflooding process, a high oil saturation that provides a sufficient supply of recoverable oil is the primary criterion for successful flooding operations. Note that higher oil saturation at the beginning of flood operations increases the oil mobility "λo" which contributes to obtaining a higher recovery efficiency.

9.8. Reservoir Uniformity and Pay Continuity

Substantial reservoir uniformity is one of the major physical criterions for successful waterflooding. Some of the following issues regarding reservoir characteristic must be considered and evaluated to study their impacts on the success of a secondary recovery process: must be evaluated:

If the formation contains a layer of limited thickness with a very high Permeability (i.e., thief zone), rapid channeling and bypassing will develop unless this zone can be located and shut off, the producing water–oil ratios will become too high for the flooding operation to be considered profitable.

The lower depletion pressure that may exist in the highly permeable zones will also increase the water-channeling tendency due to the high permeability variations. Moreover, these thief zones will contain less residual oil than the other layers, and their flooding will lead to relatively lower oil recoveries than other layers.

Areal continuity of the pay zone is also a prerequisite for a successful waterflooding project. Isolated lenses may be effectively depleted by a single well completion, but a flood mechanism requires that both the injector and producer be present in the same lens.

Breaks in pay continuity and reservoir anisotropy caused by depositional conditions, Fractures or faulting need to be identified and described before determining the proper well spanning and the suitable flood pattern orientation.

9.9. Primary Reservoir Driving Mechanism

As describe in many textbooks, six driving mechanisms basically provide the natural energy necessary for oil recovery:

- Rock and liquid expansion
- Solution gas drive
- Gas cap drive
- Water drive

- Gravity drainage drive
- Combination drive

The recovery of oil by any of the above driving mechanisms is called primary recovery. The term refers to the production of hydrocarbons from a reservoir without the use of any process (such as water injection) to supplement the natural Energy of the reservoir. The primary drive mechanism and anticipated ultimate Oil recovery should be considered when reviewing oil fields for possible development by waterflood. The approximate oil recovery range is tabulated below for various driving mechanisms. Note that these estimates are only approximations and, therefore, oil recovery may fall outside these ranges.

Driving mechanisms	**Oil recovery range, %**
Rock and liquid expansion	3-7
Solution gas drive	20-35
Gas cap drive	20-45
Water drive	35-75
Gravity drainage drive	<80
Combination drive	30-60

Table 1 Oil Recovery Range

9.10. Optimum time to waterflood

The most common procedure for determining the optimum time to start waterflooding is to calculate:

- Anticipated oil recovery
- Fluid production rates
- Anticipated financial investment
- Availability and quality of the water supply
- Costs of water treatment and pumping equipment
- Costs of maintenance and operation of the water installation facilities
- Costs of drilling new injection wells or converting existing production wells into injectors.

These calculations should be performed for several assumed times and the net income for each case determined. The scenario that maximizes the profit and perhaps meets the operator's desirable goal is selected. Cole (1969) lists the following factors as being important when determining the reservoir pressure (or time) to initiate a secondary recovery project:

Reservoir oil viscosity:

Water injection should be initiated when the reservoir pressure reaches its bubble-point pressure since the oil viscosity reaches its minimum value at this pressure. The mobility of the oil will increase with decreasing oil viscosity, which in turns improves the sweeping efficiency.

Free gas saturation:

The impact of the free must be considered when plaining field development by water of gas injection.

In water injection projects. It is desirable to have an initial gas saturation, possibly as much as 10%. This suggests that there might be benefits of initiating the waterflood process at a pressure that is below the bubble point pressure (discussed in detailed later in this chapter).

In gas injection projects. Zero gas saturation in the oil zone is desired. This occurs while reservoir pressure exists at or above bubble-point pressure.

Cost of injection equipment:

This is related to reservoir pressure which indicates that at higher pressures, the cost of injection equipment increases. Therefore, a low reservoir pressure at initiation of injection is desirable.

Productivity of producing wells:

A high reservoir pressure is desirable to:

- Increase the productivity of producing wells
- Extend the flowing period of the wells
- Decrease lifting costs
- Shorten the overall life of the project
- Effect of delaying investment on the time value of money.

A delayed investment in injection facilities might be desirable for the standpoint that an opportunity might exist to use the available fund for another investment.

Overall life of the reservoir. Because operating expenses are an important part of total costs, the fluid injection process should be started as early as possible.

Some of these six factors act in opposition to others. Thus, the actual pressure at which a fluid injection project should be initiated will require optimization of the various factors in order to develop the most favorable overall economics.

The principal requirement for a successful fluid injection project is that sufficient oil must remain in the reservoir after primary operations have ceased to render economic the secondary recovery operations. This high residual oil saturation after primary recovery is essential not only because there must be a sufficient volume of oil left in the reservoir, but also because of relative permeability considerations. A high oil relative permeability, i.e., high oil saturation, means more oil recovery with less production of the displacing fluid. On the other hand, low oil saturation means a low oil relative permeability with more production of the displacing fluid at a given time.

10. RESERVOIR DATA COLLECTION

Reservoir data we used in this case study is from the open-source data which was available in GitHub website. We used SPE9 data to analyze the simulations.

```
-----------------------------------------------------------------------------------------------------
----------------------------------------------SPE9-----------------------------------------------
-----------------------------------------------------------------------------------------------------

RUNSPEC


TITLE

        SPE 9


DIMENS

        24 25 15 /

OIL

WATER

GAS

DISGAS

-- From figure 7 in Killough's paper it is evident

-- that GOR is increasing with time, meaning

-- that there must be dissolved gas present


FIELD


START

        1 'JAN' 2015 /


WELLDIMS
```

```
-- Item 1: maximum number of wells in the model
--          - there are 26 wells in SPE9; 1 injector and 25 producers
-- Item 2: maximum number of grid blocks connected to any one well
--          - the injector is completed in 5 layers
-- Item 3: maximum number of groups in the model
--          - only one group in model
-- Item 4: maximum number of wells in any one group
--          - this can definitetly not be more than 26
         26 5 1 26 /
TABDIMS
-- The number of rows in SWOF exceeds the default maximum,
-- so item 3 in this keyword must be changed:
         1* 1* 40 /

EQLDIMS
/

--NSTACK
--       25 /
-- Eclipse suggested increasing NSTACK

UNIFOUT

GRID
-- Killough says 'the grid was in conventional rectangular
-- coordinates without corner point geometry or local grid refinements'
```

```
NOECHO
DX
-- There are in total 9000 cells with length 300ft in x-direction
        9000*300 /
DY
-- There are in total 9000 cells with length 300ft in y-direction
        9000*300 /
DZ
-- The thicknesses of the layers are given in table 1 in Killough's paper
-- In each layer there are 600 cells
        600*20
        600*15
        600*26
        600*15
        600*16
        600*14
        600*8
        600*8
        600*18
        600*12
        600*19
        600*18
        600*20
        600*50
        600*100 /
```

```
-- TOPS
INCLUDE
        TOPSVALUES.DATA /

PORO
-- Porosity in each level is contant
-- The values are specified in table 1 in Killough's paper
        600*0.087
        600*0.097
        600*0.111
        600*0.16
        600*0.13
        600*0.17
        600*0.17
        600*0.08
        600*0.14
        600*0.13
        600*0.12
        600*0.105
        600*0.12
        600*0.116
        600*0.157 /

-- PERMX, PERMY & PERMZ
INCLUDE
```

```
        PERMVALUES.DATA /


ECHO


PROPS


PVTW
-- Item 1: pressure reference (psia)
-- Item 2: water FVF (rb per bbl or rb per stb)
-- Item 3: water compressibility (psi^{-1})
-- Item 4: water viscosity (cp)
-- Item 5: water 'viscosibility' (psi^{-1})


-- Item 1 and 2 are stated in Killough, and item 5 is assumed = zero
-- Item 3 and 4 are taken from SPE2
        3600 1.0034 3e-6 0.96 0 /
--NOTE:
--  a)  It is not explicitly stated in Killough that it is okay to use SPE2-values here.
--  b)  I am not 100% sure if the given compressibility value is at ref. pres. 3600psia.
--  c)  Item 3 and 4 can probably be explained on the basis of Killough's dataset. In
--      order to do that I need info about keywords in VIP


ROCK
-- Item 1: reference pressure (psia)
-- Item 2: rock compressibility (psi^{-1})
```

```
-- Using values from SPE2:
        3600 4e-6 /
-- NOTE:
--   a) It is not explicitly stated in Killough that it is okay to use SPE2-values here.
--   a) I am not 100% sure if the given compressibility value is at 3600psia.
--   b) 'Comp. Methods for Multiphase Flow in Porous Media' states
--      that rock compr. is 1e-6 inverse psi. This is probably correct, as
--         I think this is based on Killough's dataset - to be sure, I need
--         more info about keywords in VIP.

DENSITY
-- Density (lb per ft³) at surface cond. of
-- oil, water and gas, respectively (in that order)

-- The values for oil and water are given by Killough to
-- be 0.7206 and 1.0095 gm per cc, or equivalently
-- 44.9856 and 63.0210 lb per ft³

-- A gas density of 0.07039 lb per ft³ was calculated using formula at
-- petrowiki.org/Calculating_gas_properties:
-- (28.967*Specific gravity*pressure)/(Z-factor*gas constant*temperature)
-- with the values given in Killough's table 2 at 14.7 psia (1 atm).
-- A temperature of 15C=59F was also used in the above formula.
        44.9856 63.0210 0.07039 /

PVTO
```

```
-- Column 1: dissolved gas-oil ratio (Mscf per stb)
-- Column 2: bubble point pressure for oil (psia)
-- Column 3: oil FVF for saturated oil (rb per stb)
-- Column 4: oil viscosity for saturated oil (cP)

-- Using values from table 2 in Killough's paper:
0       14.7    1       1.20 /
0.165   400     1.0120          1.17 /
0.335   800     1.0255          1.14 /
0.500   1200    1.0380          1.11 /
0.665   1600    1.0510          1.08 /
0.828   2000    1.0630          1.06 /
0.985   2400    1.0750          1.03 /
1.130   2800    1.0870          1.00 /
1.270   3200    1.0985          0.98 /
1.390   3600    1.1100          0.95 /
1.500   4000    1.1200          0.94
        5000    1.1189          0.94 /
/
-- Comment in regards to the last row in PVTO:
--  Killough says that 'at 1000psi above the saturation
--  pressure the Bo is 0.999 times that of the Bo at Psat'
--  which means that the FVF (i.e. Bo) at 5000psia is 0.999*0.1200=1.1189
--  Killough also says that 'the oil viscosity does not
--  increase with increasing pressure in undersaturated conditions'
--  which explains why the oil viscosity is 0.94.
```

```
PVDG
-- Column 1: gas phase pressure (psia)
-- Column 2: gas formation volume factor (rb per Mscf)
--            - This is calculated using formula:
--              Bg=5.03676*Z*temperature(R)/pressure(psia) rb/Mscf
--              where a constant temperature=100F=559.67R has been used because
--              that is the initial reservoir temperature according to Killough's paper
--              The above formula is retrieved from
--              petrowiki.org/Gas_formation_volume_factor_and_density
-- Column 3: gas viscosity (cP)

-- Using values from table 2 in Killough's paper:
14.7    191.7443        0.0125
400      5.8979         0.0130
800      2.9493         0.0135
1200     1.9594         0.0140
1600     1.4695         0.0145
2000     1.1797         0.0150
2400     0.9796         0.0155
2800     0.8397         0.0160
3200     0.7398         0.0165
3600     0.6498         0.0170
4000     0.5849         0.0175 /

SGOF
```

```
-- Column 1: gas saturation
-- Column 2: gas relative permeability
-- Column 3: oil relative permeability when oil, gas and connate water are present
-- Column 4: corresponding oil-gas capillary pressure (psi)

-- Using values from table 3 in Killough's paper:
0          0          1              0
0.04       0          0.6  0.2
0.1        0.022      0.33           0.5
0.2        0.1        0.1  1.0
0.3        0.24       0.02           1.5
0.4        0.34       0              2.0
0.5        0.42       0              2.5
0.6        0.5        0              3.0
0.7        0.8125     0              3.5
0.84891            0.9635     0              3.82 /
--0.88491 1          0              3.9 /
-- Comment in regards to the last row in SGOF:
--    Changes have been made so that the last row
--    is at a gas sat. of Sg=1-Swc=1-0.151090=0.84891
--    The Krg and Pcog values corresponding to Sg=0.84891
--    have been approximated by assuming linear relation between
--    Krg/Pcog and Sg in the range Sg=0.7 to Sg=0.88491

SWOF
-- Column 1: water saturation
```

```
-- Column 2: water relative permeability

-- Column 3: oil relative permeability when only oil and water are present

-- Column 4: corresponding water-oil capillary pressure (psi)


-- These values are taken from Killough's dataset:

0.151090     0.0     1.0     400.0

0.151230     0.0     0.99997 359.190

0.151740     0.0     0.99993 257.920

0.152460     0.0     0.99991 186.310

0.156470     0.0     0.999510 79.060

0.165850     0.0     0.996290 40.010

0.178350     0.0     0.991590 27.930

0.203350 0.000010    0.978830 20.400

0.253350 0.000030    0.943730 15.550

0.350000 0.000280    0.830230 11.655

0.352000 0.002292    0.804277  8.720

0.354000 0.004304    0.778326  5.947

0.356000 0.006316    0.752374  3.317

0.358000 0.008328    0.726422  1.165

0.360000 0.010340    0.700470  0.463

0.364395 0.015548    0.642258 -0.499

0.368790 0.020756    0.584046 -1.139

0.370000 0.022190    0.568020 -1.194

0.380000 0.035890    0.434980 -1.547

0.400000 0.069530    0.171430 -1.604

0.433450 0.087900    0.125310 -1.710
```

```
0.461390 0.104910    0.094980 -1.780
0.489320 0.123290    0.070530 -1.860
0.517250 0.143030    0.051130 -1.930
0.573120 0.186590    0.024640 -2.070
0.601060 0.210380    0.016190 -2.130
0.656930 0.261900    0.005940 -2.260
0.712800 0.318650    0.001590 -2.380
0.811110 0.430920    0.000020 -2.600
0.881490 0.490000    0.000000 -2.750 /


-- These values are approximated by reading off the graphs
-- in figure 1 and 2 in Killough's paper:
-- $$$ 0.18       0        1     21
-- $$$ 0.25       0        0.95  16
-- $$$ 0.34       0.07     0.5   12
-- $$$ 0.345      0.08     0.4    9
-- $$$ 0.35       0.09     0.3    6
-- $$$ 0.355      0.095    0.2    0
-- $$$ 0.36       0.1      0.19  -2
-- $$$ 0.75       0.32     0.02  -2.5
-- $$$ 0.88149    0.5      0     -3 /


SOLUTION
```

```
EQUIL
-- Item 1: datum depth (ft)
-- Item 2: pressure at datum depth (psia)
--           - Killough says initial oil phase pressure is
--           - 3600psia at depth 9035ft
-- Item 3: depth of water-oil contact (ft)
--           - Given to be 9950 ft in Killough's paper
-- Item 4: oil-water capillary pressure at the water oil contact (psi)
--           - Given to be 0 in Killough's dataset
--           - 0 in SPE2
-- Item 5: depth of gas-oil contact (ft)
--           - 8800ft in Killough's dataset
-- Item 6: gas-oil capillary pressure at gas-oil contact (psi)
--           - Given to be 0 in Killough's dataset
--           - 0 in SPE2
-- Item 7: RSVD-table
-- Item 8: RVVD-table
-- Item 9: OPM only supports item 9 equal to zero.

--      #: 1    2    3    4 5    6 7 8 9
            9035 3600 9950 0 8800 0 1 0 0 /

RSVD
-- The initial oil phase pressure is given to be 3600psia, at
-- which the GOR is 1.39 Mscf per stb according to Killough's table 2.
-- Since there is no free gas initially present*, the oil
```

```
-- phase (with dissolved gas) must initially have a constant GOR as
-- a function of depth through the reservoir (at the given pressure)
        8800 1.39
        9950 1.39 /
-- *)
--   This is explicitly stated in Killough's paper.
--   Note that the initial oil phase pressure is the same as
--   the saturation (bubble point) pressure of the oil.
--   This should also imply that there is no free gas initially present.
--   Since there is no free gas initially present, the gas-oil
--   contact should lie above the reservoir, which it does (EQUIL, item 5)

SUMMARY

-- Killough's figure 7:
FGOR
-- Killough's figure 8:
FOPR
-- Killough's figure 9:
FGPR
-- Killough's figure 10:
FWPR
-- Killough's figure 11:
BPR
 1 1 1 /
/
```

```
-- Killough's figure 12:
BGSAT
 1 13 1 /
/
-- Killough's figure 13:
BWSAT
 10 25 15 /
/
-- Killough's figure 14:
--WWIR
-- 'INJE1' /
-- Killough's figure 15:
--WOPR
-- 'PRODU21' /


-- In order to compare Eclipse with Flow:
WBHP
/
WGIR
/
--WGIT
--/
WGPR
/
--WGPT
--/
```

```
WOIR
/
--WOIT
--/
WOPR
/
--WOPT
--/
WWIR
/
--WWIT
--/
WWPR
/
--WWPT
--/


SCHEDULE


RPTRST
        'BASIC=4' /
WELSPECS
-- Column 3: I-value of well head or heel
-- Column 4: J-value of well head or heel
--           - these coordinates are listed in Killough's dataset
-- Column 5: ref. depth of BHP (ft)
```

```
--              - stated to be 9110ft in Killough
-- Column 6: preferred phase for well
--              - should be water for injector and oil for producers
-- Column 7: drainage radius for calc. of productivity or
--          injectivity indices (ft)
--              - stated to be 60ft in Killough


-- #: 1        2   3  4 5    6        7
   'INJE1'   'G' 24 25   9110   'WATER' 60   /
   'PRODU2'  'G'  5  1 9110   'OIL'   60   /
   'PRODU3'  'G'  8  2 9110   'OIL'   60   /
   'PRODU4'  'G' 11  3        9110   'OIL'   60   /
   'PRODU5'  'G' 10  4        9110   'OIL'   60   /
   'PRODU6'  'G' 12  5        9110   'OIL'   60   /
   'PRODU7'  'G'  4  6 9110   'OIL'   60   /
   'PRODU8'  'G'  8  7 9110   'OIL'   60   /
   'PRODU9'  'G' 14  8        9110   'OIL'   60   /
   'PRODU10' 'G' 11  9        9110   'OIL'   60   /
   'PRODU11' 'G' 12 10        9110   'OIL'   60   /
   'PRODU12' 'G' 10 11        9110   'OIL'   60   /
   'PRODU13' 'G'  5 12        9110   'OIL'   60   /
   'PRODU14' 'G'  8 13        9110   'OIL'   60   /
   'PRODU15' 'G' 11 14        9110   'OIL'   60   /
   'PRODU16' 'G' 13 15        9110   'OIL'   60   /
   'PRODU17' 'G' 15 16        9110   'OIL'   60   /
   'PRODU18' 'G' 11 17        9110   'OIL'   60   /
```

```
   'PRODU19' 'G' 12 18        9110   'OIL'   60   /
   'PRODU20' 'G'  5 19        9110   'OIL'   60   /
   'PRODU21' 'G'  8 20        9110   'OIL'   60   /
   'PRODU22' 'G' 11 21        9110   'OIL'   60   /
   'PRODU23' 'G' 15 22        9110   'OIL'   60   /
   'PRODU24' 'G' 12 23        9110   'OIL'   60   /
   'PRODU25' 'G' 10 24        9110   'OIL'   60   /
   'PRODU26' 'G' 17 25        9110   'OIL'   60   /
/


COMPDAT
-- Column 2: I-value of connecting grid block
-- Column 3: J-value of connecting grid block
-- Column 4: K-value of upper connecting grid block
-- Column 5: K-value of lower connecting grid block
--           - these coordinates are listed in Killough's dataset
-- Column 9: well bore diameter
--           - Killough says radius is 0.5ft


-- #: 1              2  3  4    5    6      7        8        9
    'INJE1'       24 25  11   15 'OPEN'1*       1*       1 /
    'PRODU2'       5  1          2    4  'OPEN'1*       1*       1 /
    'PRODU3'       8  2          2    4  'OPEN'1*       1*       1 /
    'PRODU4'      11  3          2    4  'OPEN'1*       1*       1 /
    'PRODU5'      10  4          2    4  'OPEN'1*       1*       1 /
    'PRODU6'      12  5          2    4  'OPEN'1*       1*       1 /
```

```
    'PRODU7'      4  6        2   4  'OPEN'1*      1*      1 /
    'PRODU8'      8  7        2   4  'OPEN'1*      1*      1 /
    'PRODU9'     14  8        2   4  'OPEN'1*      1*      1 /
    'PRODU10'    11  9        2   4  'OPEN'1*      1*      1 /
    'PRODU11'    12 10        2   4  'OPEN'1*      1*      1 /
    'PRODU12'    10 11        2   4  'OPEN'1*      1*      1 /
    'PRODU13'     5 12        2   4  'OPEN'1*      1*      1 /
    'PRODU14'     8 13        2   4  'OPEN'1*      1*      1 /
    'PRODU15'    11 14        2   4  'OPEN'1*      1*      1 /
    'PRODU16'    13 15        2   4  'OPEN'1*      1*      1 /
    'PRODU17'    15 16        2   4  'OPEN'1*      1*      1 /
    'PRODU18'    11 17        2   4  'OPEN'1*      1*      1 /
    'PRODU19'    12 18        2   4  'OPEN'1*      1*      1 /
    'PRODU20'     5 19        2   4  'OPEN'1*      1*      1 /
    'PRODU21'     8 20        2   4  'OPEN'1*      1*      1 /
    'PRODU22'    11 21        2   4  'OPEN'1*      1*      1 /
    'PRODU23'    15 22        2   4  'OPEN'1*      1*      1 /
    'PRODU24'    12 23        2   4  'OPEN'1*      1*      1 /
    'PRODU25'    10 24        2   4  'OPEN'1*      1*      1 /
    'PRODU26'    17 25        2   4  'OPEN'1*      1*      1 /
/


WCONINJE
-- Killough says the water injector is set to a max rate of
-- 5000 STBW per D with a max BHP of 4000psia at a reference
-- depth of 9110ft subsea:
```

```
--  #:  1           2     3     4    5     7
        'INJE1' 'WATER' 'OPEN' 'RATE' 5000 1* 4000 /
/


WCONPROD
-- Killough says the max oil rate for all producers is set to
-- 1500 STBO per D at time zero and that the min flowing BHP
-- is set to 1000psia (with a ref. depth of 9110ft for this pressure in all wells):
--  #:  1         2     3    4     9
         'PRODU*' 'OPEN' 'ORAT' 1500 4* 1000  /
-- Here, the wildcard '*' has been used to indicate that this applies
-- to all producers; PRODU1-PRODU25.
/


TSTEP
30*10 /


-- At 300 days, the max oil rate for all producers is lowered
-- to 100 STBO per D:
WCONPROD
--  #:  1         2     3    4     9
         'PRODU*' 'OPEN' 'ORAT' 100 4* 1000 /
/


TSTEP
6*10 /
```

```
-- At 360 days, the max oil rate for all producers is changed
-- back to 1500 STBO per D:
WCONPROD
--   #:  1         2     3    4      9
          'PRODU*' 'OPEN' 'ORAT' 1500 4* 1000 /
/

TSTEP
54*10 /
-- End of simulation at 900 days

END
```

Table 2 SPE9 Data

11. RESULTS OF RESERVOIR SIMULATION USING DATA

11.1. SPE9 Model

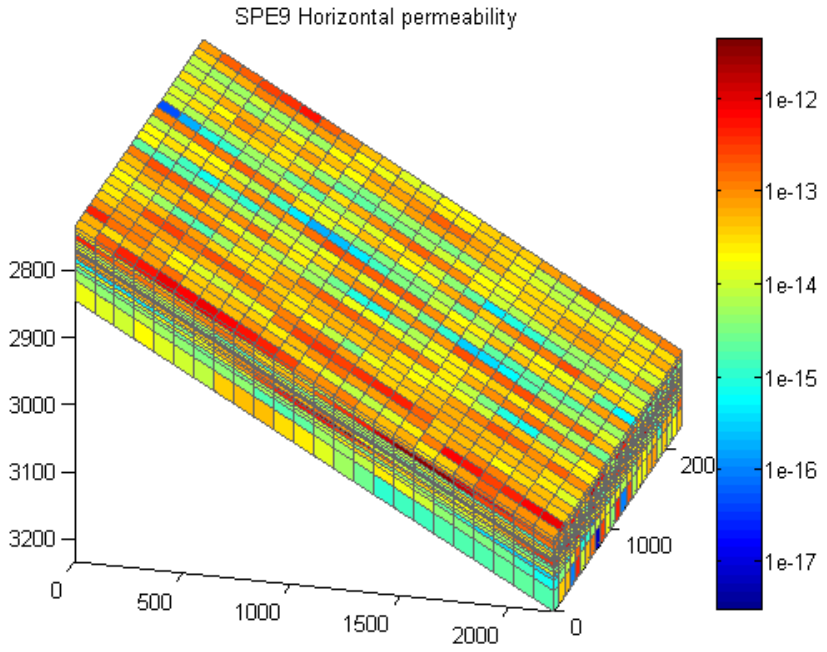

Figure 31 SPE9 Horizontal Permeability

11.2. Relative Permeability Curves

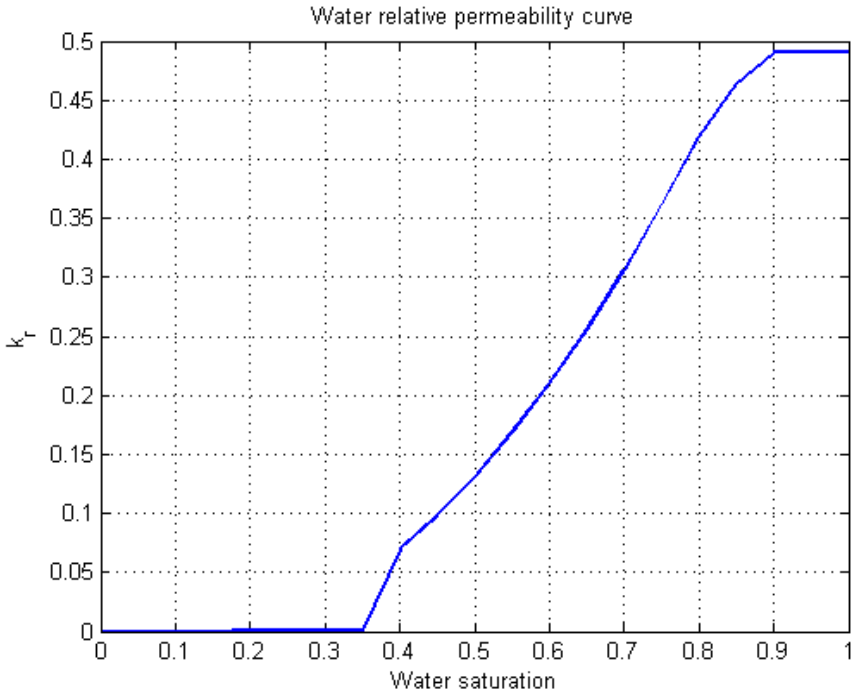

Figure 32 Water Relative Permeability Curve

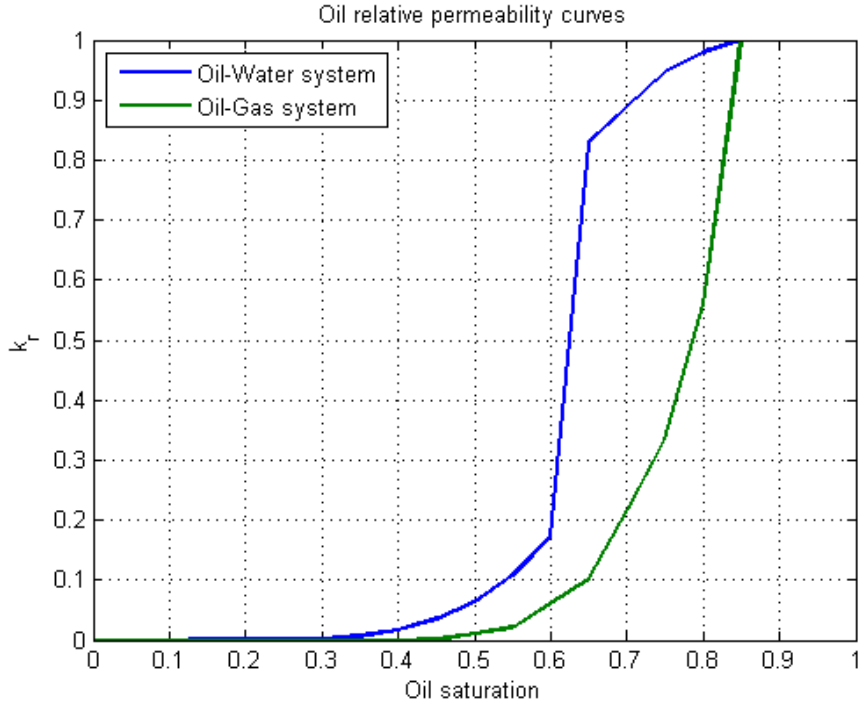

Figure 33 Oil Relative Permeability Curves

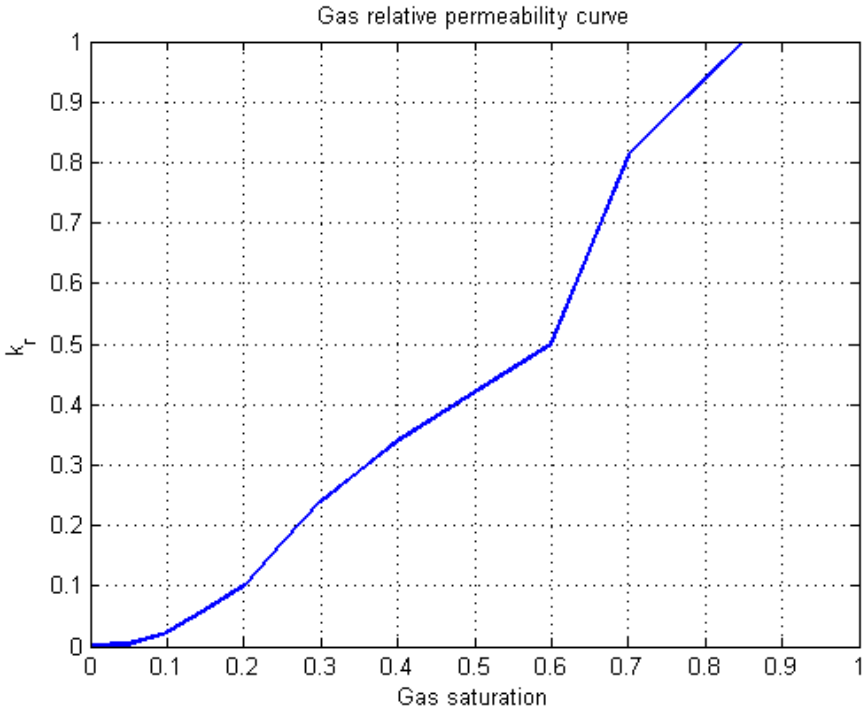

Figure 34 Gas Relative Permeability Curve

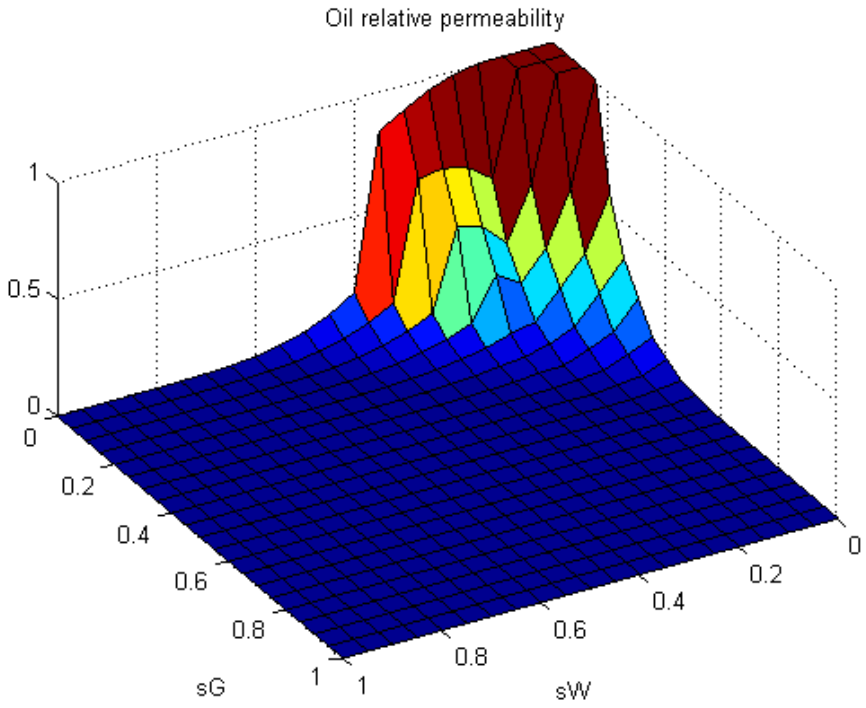

Figure 35 Three-Phase Relative Permeability

11.3. Capillary Pressure Curves

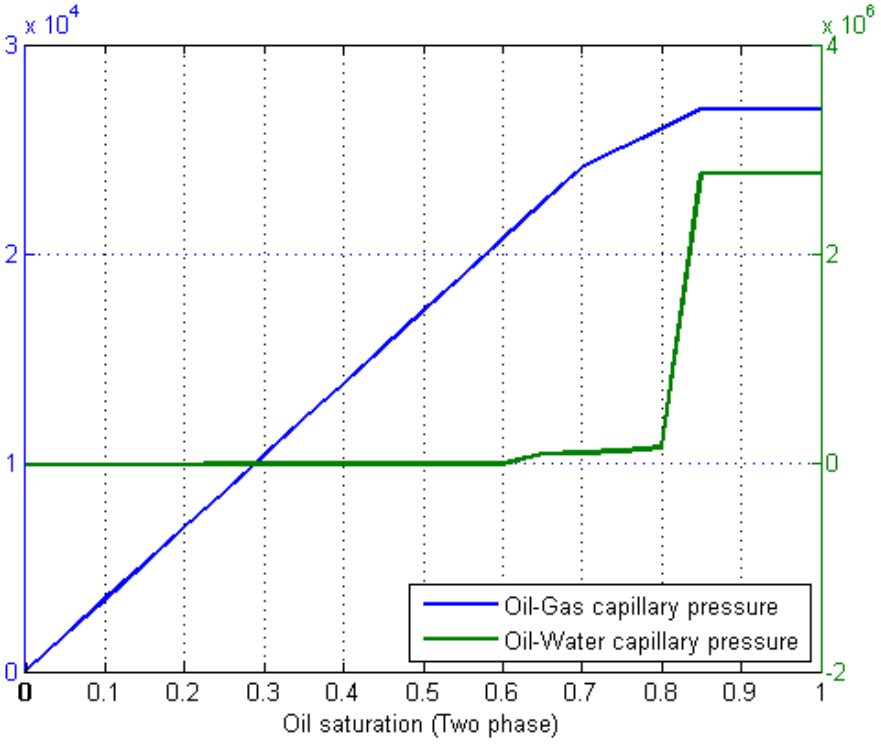

Figure 36 Capillary Pressure Curves

11.4. Compressibility

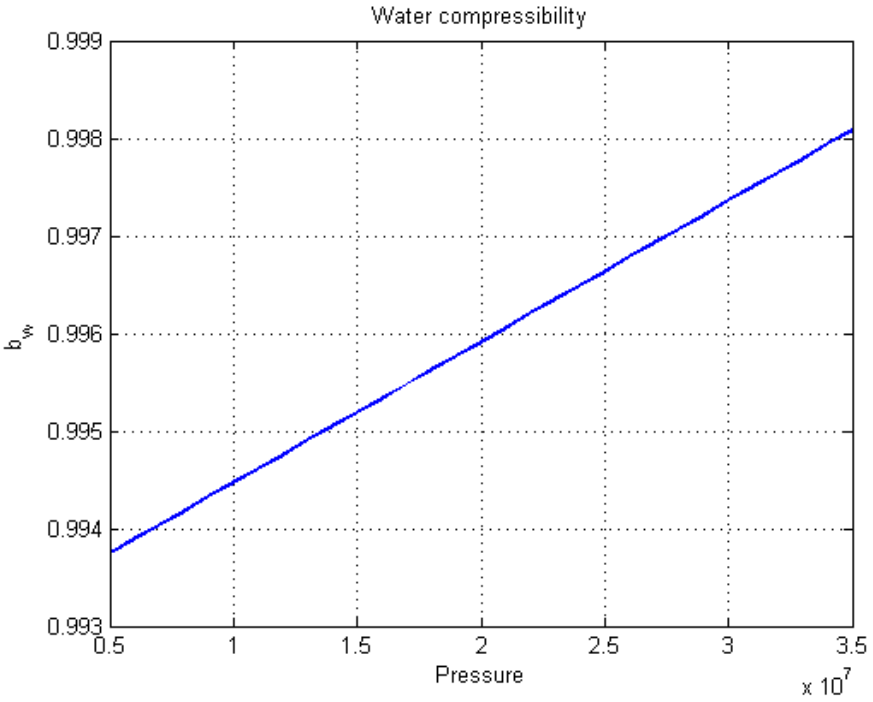

Figure 37 Water Compressibility

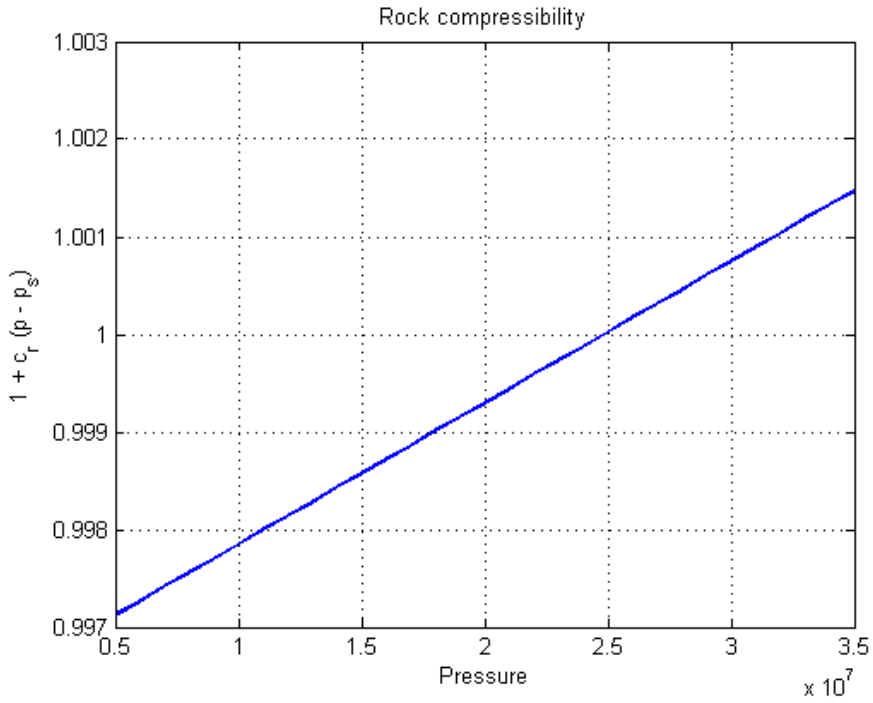

Figure 38 Rock Compressibility

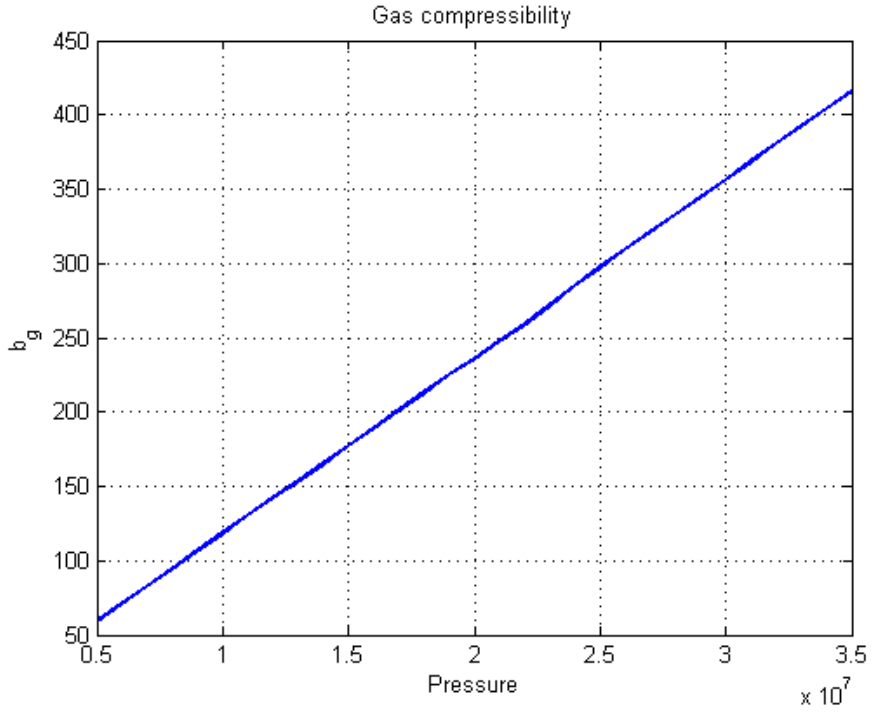

Figure 39 Gas Compressibility

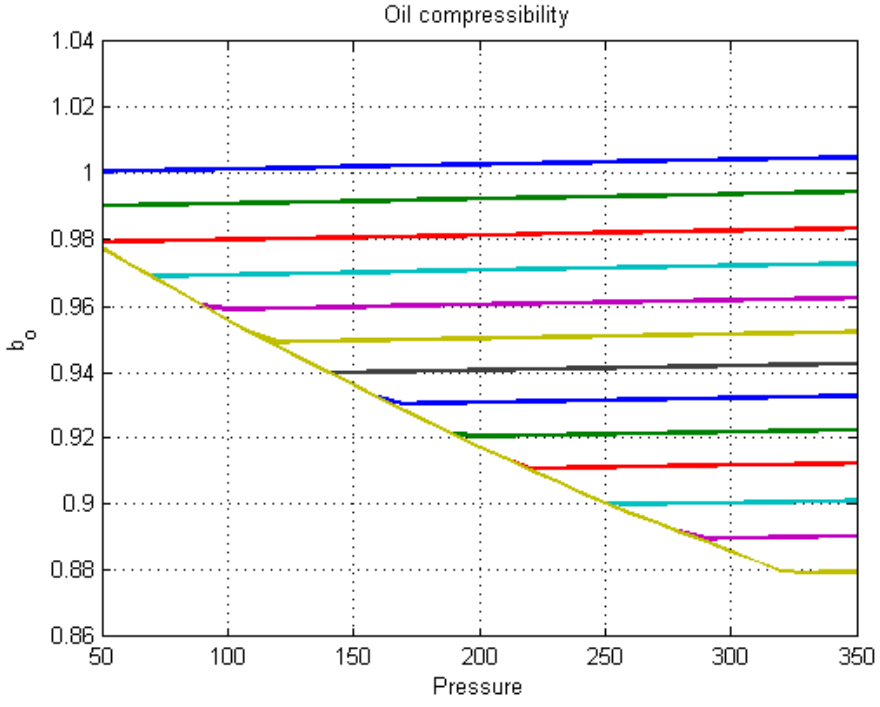

Figure 40 Oil Compressibility

11.5. Permeability Plots

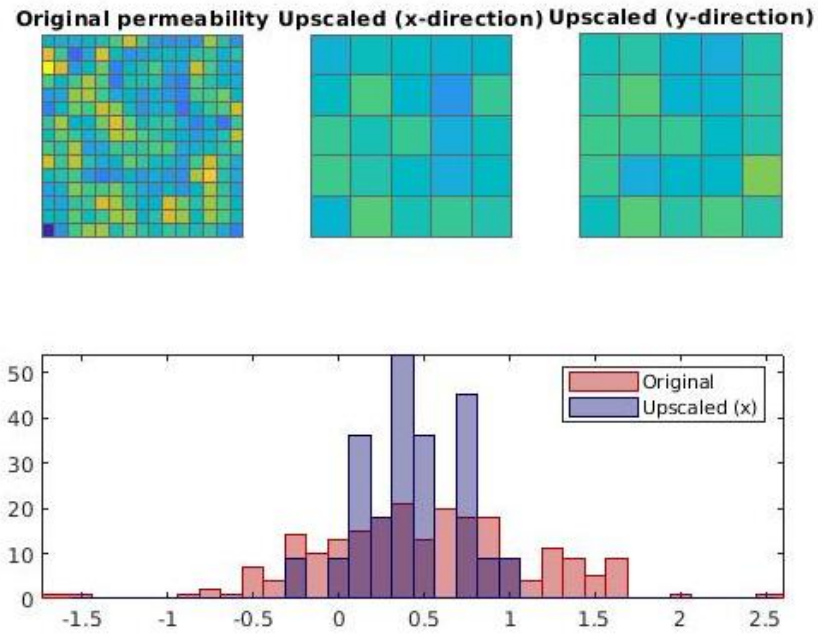

Figure 41 Original & Upscaled Permeability

11.6. Stationary State Flow

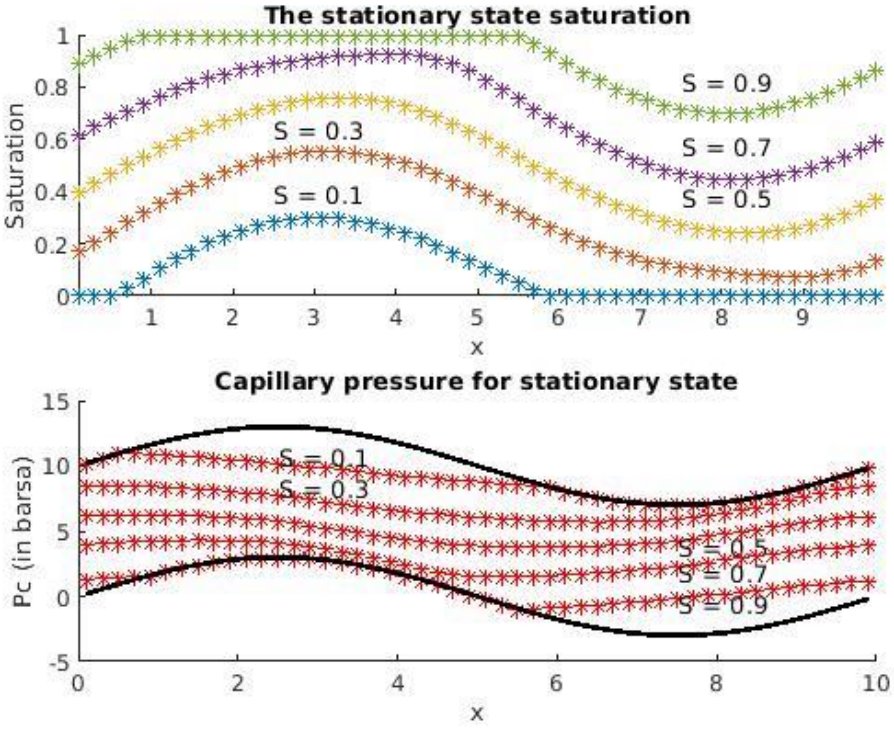

Figure 42 Saturation & Capillary Pressure for Stationary state

11.7. Single Phase Black Oil

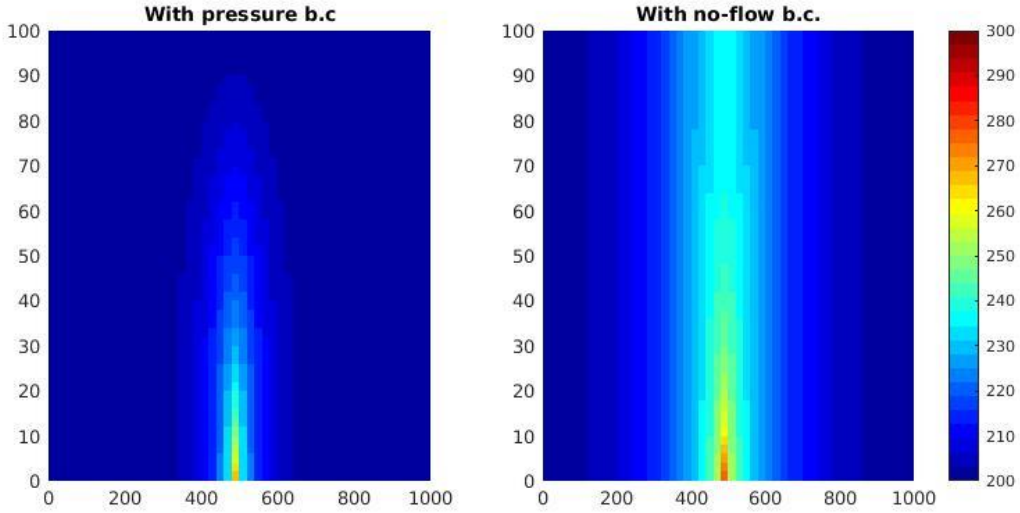

Figure 43 Single Phase Black Oil

11.8. Optimization Graphs

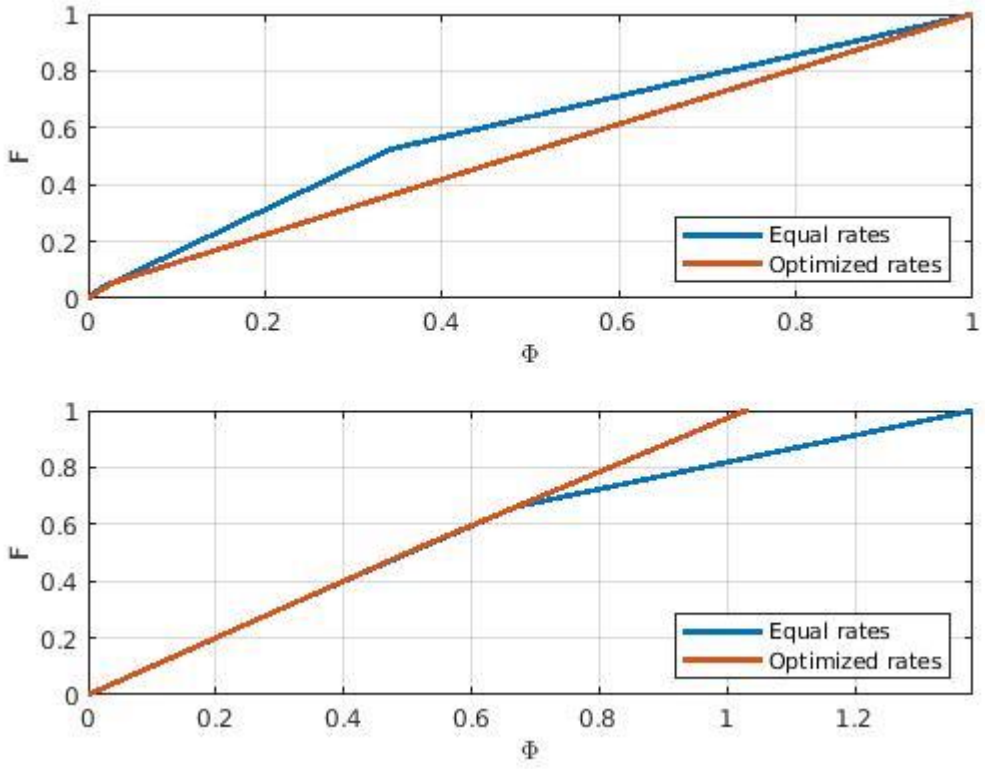

Figure 44 Optimized Rates Graph

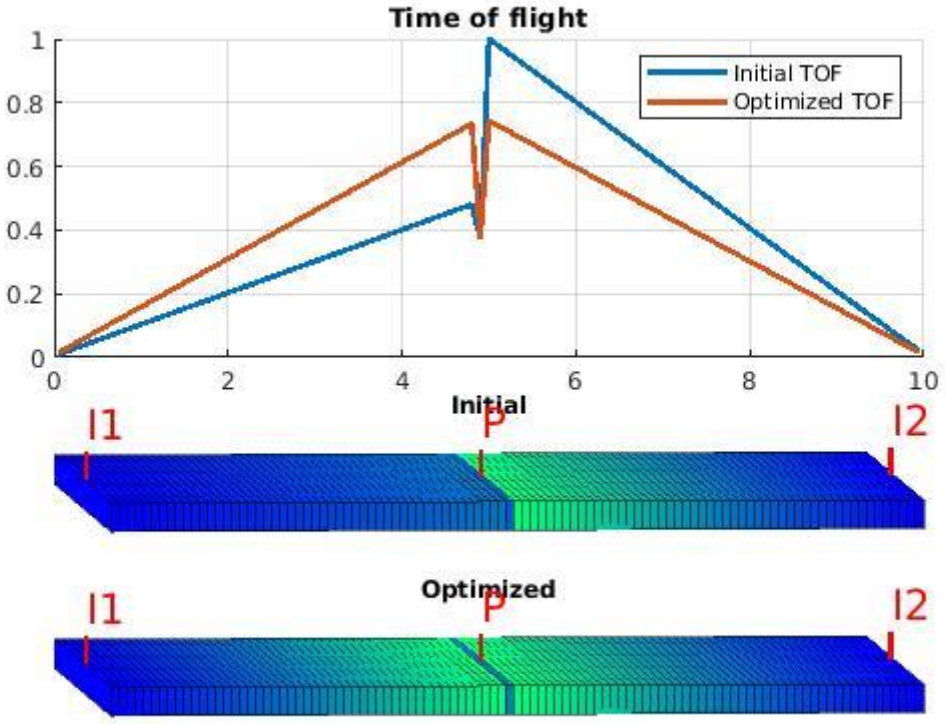

Figure 45 Initial and Optimized Time of Flight

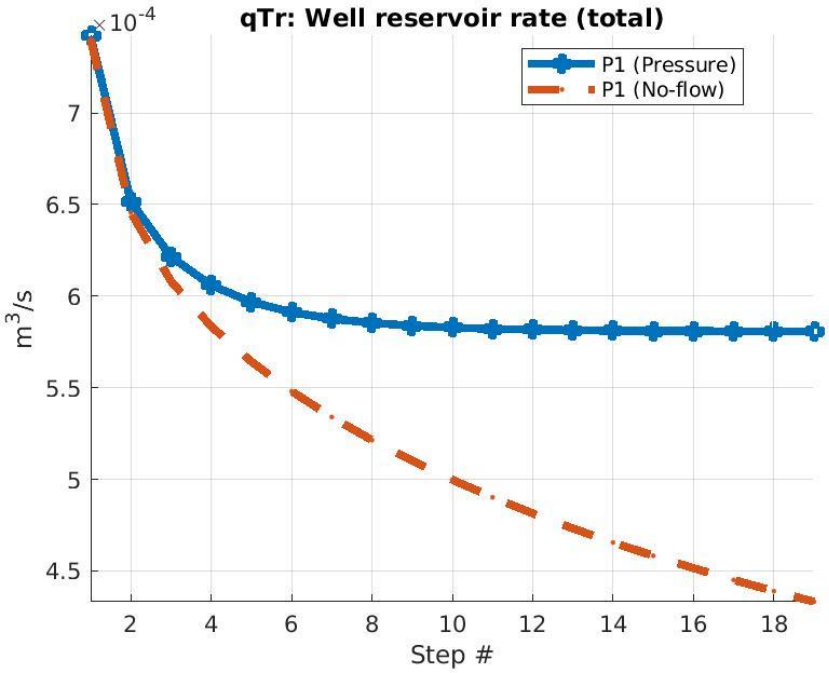

Figure 46 Total Well Reservoir Rate Graph

11.9. Upscaling Injection & Production Plots

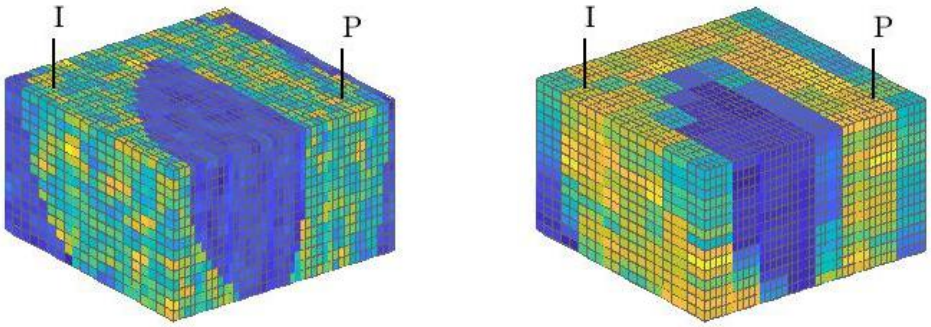

Figure 47 Upscaling Diagnostics

12. CONCLUSION

From the results obtained, it can be concluded that: Reservoir simulation is a **mature technology.** simulation results will guide most major reservoir-development decisions in some way. Despite of this maturity, the technology is changing rapidly, and both providers and users of reservoir simulation software must understand the future of these changes. The geo statistical tool of co-simulation is a reliable and efficient tool for modelling and distributing reservoir Petro physical properties in a model. Building of multiple equiprobable realizations of reservoir properties and ranking them are an efficient approach to reservoir characterization. This approach reduces uncertainties associated with reservoir properties estimation. The combination of generating numerous equiprobable distributions of reservoir property and using numerical simulation to evaluate fluids distribution is an extremely useful approach for reservoir performance analysis. Waterflood was optimized using an approach that considered the zones of injection and production, the pattern of waterflood and the number and type of producers/injectors. A reservoir simulation also is widely used in oil and gas industry to predict reservoir performance based on, black-oil and compositional simulators, these are very much important to create the models through the accurate data gathering from field production. To differentiate each element, we will have the right to explain each simulator in detail; black-oil simulator data obtained from the reservoir is to evolution of dissolved gas in oil, or vaporization or dropout of condensate from gas whereas the use of compositional reservoir simulator is to calculate the PVT properties of oil and gas phases once they have been fitted to an equation of state (EOR) as a mixture of components. The simulation model computes the saturation of three phases (oil, gas and water) and pressure of each phase in each cell at each time step.

A simulation project of a developed field usually requires “history matching “where historical field production and pressure are compared to calculated values. To answer our case study “approached to waterflooding optimization”, these parameters have been realized at an early stage that pressure depletion, waterflooding, solution-gas injection and polymer flooding for black-oil and miscible/immiscible gas (CO2) injection were essentially an optimization process, corresponding to maximum likelihood(probability).

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