EG4013 – MEng Engineering Report (Winter Progress Report) **January, 2015**

Review of the *Winter Report* 'Work-Flow for Reservoir Simulation: From Mapping to Simulation' by Kristoffer Ritchie

The manuscript reports current technologies used by the oil and gas industry to predict reservoir production behaviour and performance. Mr Ritchie divided the reservoir simulation workflow in nine stages, from core and well testing to history matching procedures. The primary engineering aim of the project is to review the main technologies in the reservoir simulation workflow in a (as much as it is possible) comprehensive and interconnected way.

The manuscript is relatively well-written with a number of typos and unrevised sentences. Most of all, the paper is well-structured with clear division, although with diffuse linkages between sections, leading to a relatively smooth reading. A few general comments,

1. The main aim of *Abstracts* is to briefly describe the work undertaken by the author. In general *Abstracts* are divided in 4 parts: (i) motivation, (ii) main objectives, (iii) summary of the main procedures / techniques / technologies (optional) and (iv) main findings. The current *Abstract* encompass (i) and partially (ii).

2. The main *Introduction* section usually has the same (but more in-depth and descriptive) four parts of the *Abstract* and a brief summary of the remaining of the work. In addition, it is always expected a few clear statements -re main background (thus recent innovations related to the main topic), initial literature review and, most of all, technological / scientific gaps in the current understanding. Also, it is expected a summary of the remaining sections at the end of the *Introduction*. Current *Introduction* covered only (ii) and (iii) above but lacked explain/summarise the main state-of-the-art aspects of the subject area. In fact, the *Introduction* section introduces and describes the main project objectives and the general workflow structure that is outlined in Sections 2-10. However, a linkage between the Introduction and the remaining of the owrk is missing.

3. You must avoid use *colloquial (informal / personal)* writing.

4. A few *References* follows different standards with missing fields and no clear distinction between articles, conference proceedings, reports (internal or external), book chapters, books, communications (internal or external) etc. A few *references* used in the manuscript are incomplete and/or wrong. Regardless of the chosen citation style (e.g., ACS, AIP, AMS, IEEE, AIAA, etc) any reference **must** contain the following fields:

   (a) For journal papers: Authors, Paper Tittle, Journal Name, Volume, Pages, Year of publication;

   (b) For books: Authors, Book Tittle, Publisher, Year or Edition;

   (c) For book chapters: Authors, Chapter Tittle, Book Tittle, Editors, Publisher, Year or Edition;

   (d) For conference papers: Authors, Paper Tittle, Conference Tittle, Place (Country and/or City) where the conference was held, Year of the conference;

(e) For reports, private communications and Lecture Notes: Authors, Tittle, Place issued (Country and/or City and Institution where the document was originated), Year;

(f) For PhD Thesis and MSc Dissertations: Author, Tittle, Institution (University and Department/School), Year.

Thus, for example:

[1] P.L. Houtekamer and L. Mitchell, 'Data Assimilation Using an Ensemble Kalman Filter Technique', *Monthly Weather Review*, 126:796-811, 1998.

[2] K. Pruess, 'Numerical Modelling of Gas Migration at a Proposed Repository for Low and Intermediate Level Nuclear Wastes', Technical Report LBL-25413, Lawrence Berkeley Laboratory, Berkeley (USA), 1990.

[3] K. Aziz, A. Settari, *Fundamentals of Reservoir Simulation*, Elsevier Applied Science Publishers, New York (USA), 1986.

[4] R.B. Lowrie, 'Compact higher-Order Numerical Methods for Hyperbolic Conservation Laws', PhD Thesis, Department of Aerospace Engineering and Scientific Computing, University of Michigan (USA), 1996.

5. Quality of figures are poor. Also, figures and tables **must** be referenced in the main text – they can not just 'float around'! Also, figure/table captions should be self-contained, i.e., with a good description of the figure/table highlighting the most relevant aspects/information that the author wants to convene.

6. Equations <u>must</u> be placed in a separated line (centered aligned with uniform font) followed by numbers (rhs aligned). All terms used must be defined afterwards as part of the main text.

7. The main objectives of the Winter report are:

   (a) Student can get familiar with:

      i. fundamental science and technologies of the main subject areas (through an in-depth literature review);

      ii. main techniques to assess/investigate the problem that will be used during the Spring term.

   (b) Student can narrow the project towards his main interests. With this in mind he can plan his research activities during the Spring.

   Mr Ritchie decided that his main focus during the Spring is to investigate fluids properties and models used in industry-standard reservoir simulations. However there is no plan of how this will be achieved.

The paper describes technologies related to reservoir simulation workflow (and hydrocabon exploration). Although there is no clear plan for actiuvities/tasks to be undertaken during the Spring term, Mr Ritchie managed to make an in-depth review of the current technologies that he will use in the second part of his project.

In the attached scanned document:

- **PE:** Poor English;
- **SC:** Sentence(s) is/are very confusing and do(es) not make much/any sense.

UNIVERSITY OF ABERDEEN

Work-Flow for Reservoir Simulation: From Mapping to Simulation

Author: Kristoffer Ritchie

Supervisor: Dr Jefferson Gomes

This report was submitted as part of the requirement for the MEng. Degree in Engineering

School of Engineering, University of Aberdeen, 19th January 2015

Abstract

Being a chemical engineer and having previously studied a geology module I was intrigued as to how geologists and engineers work together in real life projects. This and my interest in petroleum exploration and production motivated me to look in to the subject of reservoir simulation.

not very technical. This is an abstract NOT a personal statement!!

From this literature review I hope to gain an appreciation of the stages of reservoir simulation, from data mapping to the actual simulation.

COLLOQUIAL

Motivation

The process of reservoir simulation has been around since the 1930's where calculations were carried out by hand and reservoir properties (saturation, porosity etc.) were simply averaged over the reservoir length. In the 1960's, simulation techniques started to develop significantly due to the invention of computers, this allowed for more complex calculations to be completed in a shorter timescale [1]. Since then methods have developed significantly with more means to gather geological data, more advanced computing technology and a greater experience in producing reservoirs.

In this report I wish to convey how the multiple processes in reservoir simulation interact and how new technologies have allowed reservoir simulation to develop.

Obj ±?!

Abstract:

- Motivation ✓
- Objectives (report and/or project) ✓
- Summary of processes, technologies, procedures, etc (optional) ✗
- Summary of main findings/conclusions ✗

Table of Contents

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1. Introduction

Too personal!

I have always been interested in the processes that occur during the exploration and production of oil/gas reservoirs due to my close proximity to the North Sea. As a chemical engineer I rarely get a chance to see upstream oil and gas, which when given the chance, motivated me to study it further.

My main objective for this report is to obtain a global overview of the whole reservoir simulation workflow. Details of the current simulation packages available will also be given with a reference to new HPC technologies that conduct flow simulations in giant oil/gas fields. For my main thesis, I will analyse the fluids present in reservoirs, paying particular interest to the equations of state and PVT data.

dry

Initial stages in reservoir simulation involve the gathering of geological data via well logging, core analysis, well testing and seismic analysis. The obtained data is then laid on to a grid representing the whole reservoir. Transport equations like the Navier Stokes' and Darcy's are applied to these grids to model the fluid flows. Reservoir simulating programs are then able to model the whole reservoir to predict behaviour during production. These simulations may be run multiple times to obtain the correct data by relating parameters to historical reservoir data in a process called history matching.

SUCH AS

COLLOQUIAL

My initial findings were that reservoir simulation is a lengthy but vital process in terms of economy. It was also apparent that regardless of how well each stage is carried out; no simulation will perfectly model the behaviour of the physical reservoir.

linkage? what should readers expect to read?

2. Coring

Coring involves substituting the regular drilling bit with a core barrel in order to obtain lengthy samples of rock, which may give evidence of the subsurface conditions. Geologists examine these rock samples to obtain information, by simply observing or by subjecting them to chemicals in the laboratory. The results from these cores may be used in conjunction with the findings from other data gathering techniques to build up a picture of what lies beneath the surface.

not very technical!!

2.1 Bit Cuttings

During drilling, the drilling mud takes small fragments of rock(s) up to the surface via the annular section of the drill pipe. Once in the hands of a geologist, the knowledge that can be obtained from the cuttings is limited due to their small nature. The main information recovered from cuttings only requires evaluation by sight and touch to determine rock type, colour, texture, grain, hardness etc. NOT VERY TECHNICAL Boundaries may be known due to a sudden change in rock type during a certain period although this can be unreliable in wells where thin boundaries are encountered. Approximate porosity readings can be determined although these values are extremely inaccurate when compared to the values found when coring [3].

2.2 Core Analysis

Core analysis is usually not undertaken during drilling; because of this it can be expensive and time consuming. Advancements have allowed for some coring to take place throughout drilling but the samples obtained are significantly smaller and therefore give less information. In coring, the drill bit is replaced by a core barrel that in the past basically consisted of a hollow tube with a sharp edge to cut through the rock. However modern core barrels have evolved to contain enhancements such as rotation and diamond bits. Cores are incredibly valuable as they allow a large amount of information to be obtained such as dips, porosity, permeability, geological structures and evidence of faulting.

When the core reaches the wellhead, the pressure and temperature ~~is~~ ARE much lower than subsurface. This causes some oil and all the gas to disappear due to the expansion of gas. PE To combat this, cores may be sealed in a pressurised container subsurface to ensure that the core stays at the same conditions as the reservoir or the core may be rapidly frozen at the surface to ensure no fluids are lost. Even if fluid is lost at the surface, traces as small as a few parts per million may be found by exposing core samples to UV light. The use of UV light may also detect geological features such as cleavage planes and dips.

The effective porosity of a core sample may be found by liquid absorption. This consists of getting a unit of rock to absorb its maximum possible volume of an unreactive fluid e.g. benzene. The volume of liquid absorbed is the same as the volume of pores within the rock. Gas expansion and compression methods have also be known to give reliable information on the effective porosity.

For permeability to be determined a rock sample must be completely dry to ensure there is no contamination. It is then secured in place by clamps and attached to a riser and tube at opposite sides. Fluid is flown through the sample via the riser and a manometer measures the pressure drop recorded between the riser and the exit tube. The sample is also tested with air over a low range of pressure heads to ensure that turbulent conditions are not observed.

If a particularly porous sample is seen as a potential reservoir rock then a basic oil recovery test may be performed. The sample however has to be contained and kept at reservoir conditions. It is then pumped with water to drive out the oil from its pores. After as much oil as possible is recovered, the rock sample is then exposed to an acid which breaks down the rock leaving only the residual oil. This allows a comparison between the oil recovered to the oil left inside the sample. However, it is incredibly difficult to obtain accurate oil recovery values due to the fact that the samples only represent a very small section of the entire reservoir.

Water saturation of the rock may be determined in the lab by heating core samples and distilling off their water content. This water content is weighed to give the percentage saturation. However, due to the unavoidable contamination caused by the drilling mud, these saturation values can only be seen as an approximation.

3. Well Logging

Well logging involves lowering an instrument down a well on a wire line at a time where drilling has been suspended. Although a commonly used technique, logging is not used on its own due to fact that the results it gives are not completely reliable. However, when used in conjunction with core samples these results become more accurate as comparisons may be made. During the first utilisation of well logging in 1927, an electrical probe was sent down a 500m well and the measurements obtained were plotted on a graph by hand [4]. However, since the invention of computers and the development of technology, many methods of well logging now exist with much greater accuracy. For the purpose of this report only electrical, nuclear and acoustic logs will be considered.

3.1 Electrical Logs

The resistivity of a formation is defined as 'the electrical resistance of a cylinder of rock of unit length and cross-sectional area' [2], measured in ohm/m^2. Resistivity logs usually give a good indication on what fluids are present within pore spaces unless the rock formations contain a metallic ore. Due to this dependency on the fluids, resistivity values will differ with saturation, fluid salinity and the available pore space.

Another electrical log is the spontaneous potential log, which measures the magnitudes of the electrical potentials created when water travels through a porous media. These potentials have a proportional relationship with the amount of liquid entering the pores and the liquid resistivity. This may give a permeability indication due to the fact that a high permeability would mean a high volume of liquid, which in turn shows a high potential (Figure 1). At the boundary of two liquids of differing salinities, electrochemical potentials may be formed. The measurement of this potential may give an indication to the type of fluids present in formations.

Logging is never seen as a stand-alone method of investigation. They are always analysed alongside cores and bit cuttings in order to produce the most accurate representation of the sub-surface [4].

Lithology	Resistivity	Spontaneous Potential
Clay, shale	Low	Low
Sand, salt water	Low	Very high
Sand, fresh water	High	Medium
Sand, oil or gas	Very high	Very high
Limestone, compact	High	Low
Limestone, porous	Low	Very high
Limestone with oil	Very high	Very high

Figure 1 - Generalised relationship between rock lithology and electric logs [3].

TABLE

High resistivity usually leads to the presence of non-porous formations or porous formations containing non-conducting fluids such as fresh water, oil and gas. Low

TABLE

resistivity is normally an indication of a porous formation containing salt water (Figure 1). If the drilling mud penetrates the pores then this may give inaccurate results, particularly with spontaneous potential logs.

3.2 Nuclear Logs

A commonly utilised logging method is gamma-ray logs. These logs measure the natural gamma radiation that is emitted from rock formations. Usually the gamma radiation is emitted due to the presence of potassium, uranium and thorium isotopes in rocks. Gamma rich rock types include clays, feldspars, and micas and evaporates whereas low gamma readings may indicate limestone and quartz-rick sandstones.

ch

reflects

In gamma-density logs, rocks are exposed to a radiation source. When the radiation reaches the rock, it rebounds back towards the source where a sensor records its concentration. After some corrections, these results may be used to find the electron density of the rock, which in turn can give an indication of the rock porosity (Figure 2). The gamma-density logs have been very successful in finding gas-saturated sands in gas-filled holes when used alongside electrical logs.

Another type of nuclear log method is neutron-logs that involve firing neutrons directly at formations. These neutrons strike the H^+ ions that then interact with atoms contained in the rock to produce slower moving neutrons. The slow moving neutrons then react with elemental nuclei to emit gamma-radiation. Sensors in the well pick up this gamma radiation. Porous areas are shown to give low gamma readings and dense formations (anhydrites and compact limestone) give high gamma readings (Figure 2). This logging method is more an indication of rock type than fluid type due to the fact that it is difficult to distinguish between water and hydrocarbons as hydrogen is present in both fluids. They can however be used to find fluid in already known high porosity areas [4].

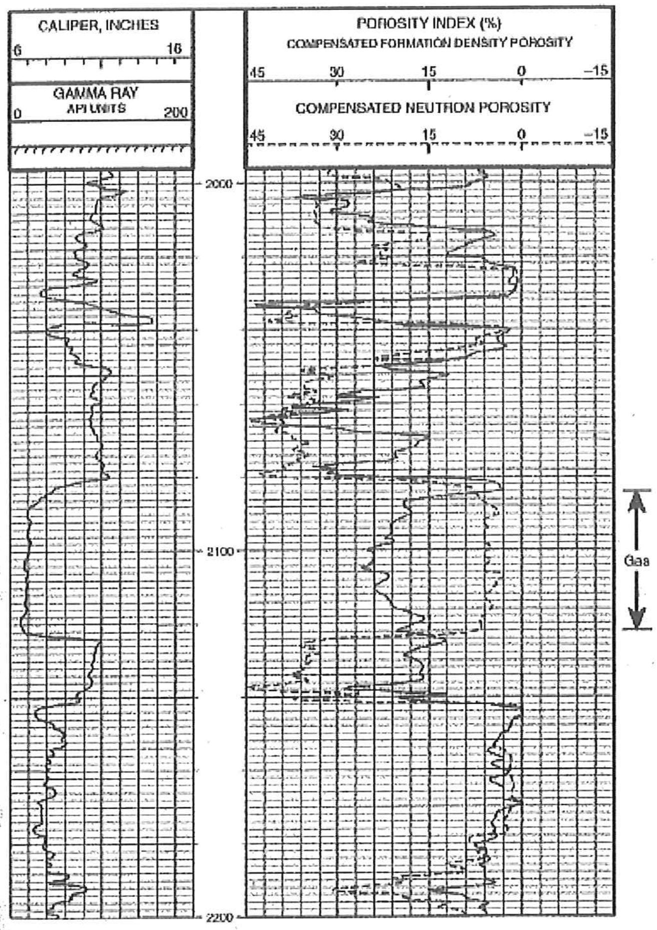

Figure 2 - Relationship between gamma ray and neutron logs [5]

Poor quality

3.3 Acoustic/Sonic Logs

The speed of sound through rock is dependent on factors including its porosity, fluid content and elastic properties. It is therefore beneficial to determine the time in which it takes for an acoustic pulse to travel through different formations. Pulses are emitted from a source in the well at a known frequency, once the receiver picks up the rebounded pulses; the transit time may be determined. A common practice in oil exploration is to have two receivers equidistantly above and below the pulse source in order to obtain an average/more accurate transit time. Porosity values found from these transit times tend to be accurate to between 5-30% and when used in conjunction with resistivity logs can find oil/gas saturations in clean formations. They also offer the ability to distinguish between oil and gas saturated sands due to their dissimilar transit times [4].

4. Well Testing

Coring and logging may give an indication on formations, structures and fluids but it is difficult to use this information to predict how a reservoir may behave during production. By implementing well tests, an idea of reservoir behaviour may be generated along with other significant statistics. The three main types of data recorded during a well test are usually pressure, time and flow rate. These variables are then usually plotted against each other to give indications of productivity and other parameters.

Pressure build-up tests (Figure 3) involve waiting for a well to be producing at a constant rate and then shutting-in the reservoir via a christmas tree assembly. The resultant pressure rise in the well is then measured by pressure gauges and plotted against time. The rate at which the pressure builds up may allow an indication of permeability, skin and ~~the~~ well pressure limit.

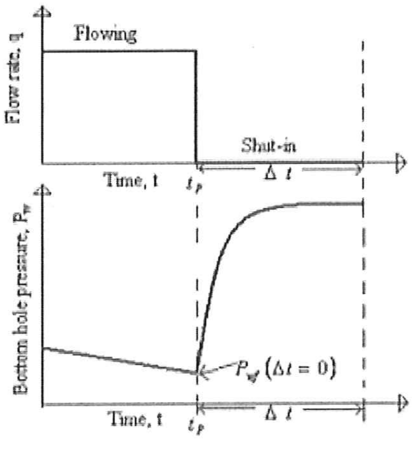

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Figure 3 – Pressure history of a build-up test [6]

For drawdown/flow tests (Figure 4), the well is shut in until a stable well head pressure is observed. The valves connecting the well to the reservoir are then gradually opened at a constant rate while the pressure change is observed via numerous measuring equipment in the well. These tests have the advantage of giving an idea of the reservoir volume along with skin and permeability properties.

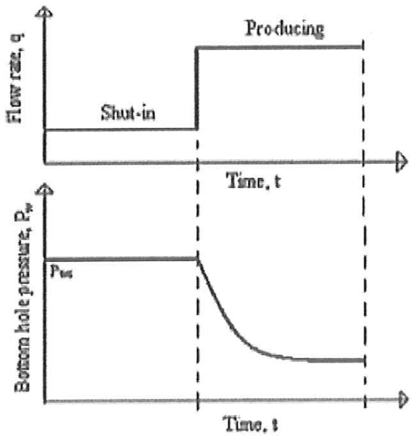

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Figure 4 – Pressure response from drawdown testing [6].

Injectivity tests comprise of pumping water in to a well at various rates as a pressure gauge (placed at a certain depth) measures the pressure differences. When the flow is initially started, the pressure in the well is allowed to stabilise, the flow is then stopped and the time taken for the well to return to its natural pressure is observed. This is repeated for different pressure gauge depths (commonly near areas of known permeability) and varying water flow rates. The obtained well pressures are then plotted against time to give an idea of the total permeability and an approximation of the well productivity.

When multiple wells are producing, interference and pulse tests may be performed. In both tests, one well is shut in (observation well) and filled with sensitive pressure recording equipment. The difference between the tests arises in the second well (active well). For an interference test, the flow rate in the active well is varied and the pressure is measured in the observation well. In pulse tests, the active well is shut-in and then allowed to flow during which the pressure is again recorded in the observation well. This may be performed continually on a certain time interval in order to gain accurate results. These tests allow permeability to be found but will only give a single permeability value which, when considering the distance between the observation and active well, may be deemed inaccurate.

Drillstem tests (Figure 5) are performed during well construction in order to give information on fluid and formation properties. A special tool consisting of sealing devices called packers and valves are lowered to a section of interest in the well. Here they isolate a zone in which samples of the fluids present are taken. Pressure readings may also be obtained during periods of shut-in [6].

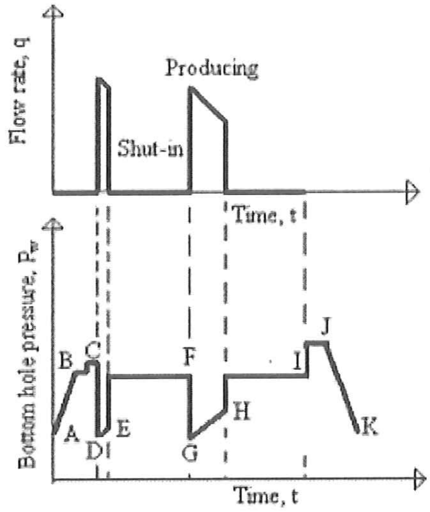

Figure 5 – Time profile of pressure for a drillstem test [6]

5. Seismic Data

Another means to study sub-surface conditions are seismic surveys, which measure the travel times of shockwaves to indicate lithology, faults, dips and other geological features. With land surveys, explosives are usually packed in a hole on the ground in such a way that the efficiency of the resultant elastic waves are maximised. Shockwaves may also be generated through means of synchronised vibrators or the dropping of heavy weights. The shockwaves result in 3 different wave types: longitudinal wave (P wave), transverse wave (S wave) and the surface wave (Rayleigh wave). These waves ~~all~~ travel at different velocities with the fastest being the P wave – the most utilised wave in petroleum seismic exploration. When a wave strokes a boundary between 2 formations of different properties, 4 new waves are created: reflected longitudinal ~~wave~~, refracted longitudinal ~~wave~~, reflected transverse ~~wave~~ and ~~the~~ refracted transverse waves (Figure 6) [3].

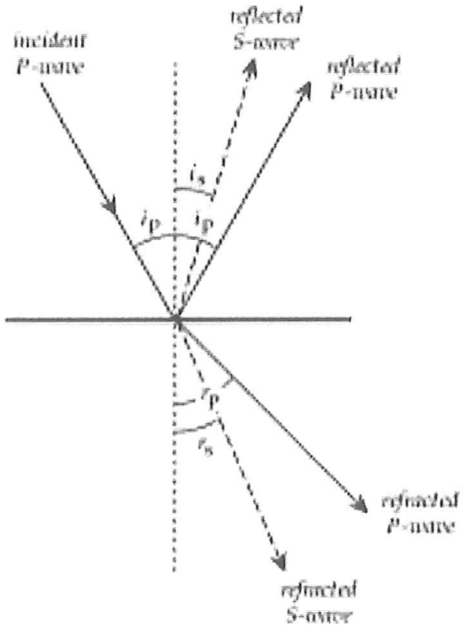

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Figure 6 - Refraction and reflection of a P wave and S wave [7].

If the angle of incidence is critical, the refracted longitudinal wave will travel directly along the border of the two formations. Geophones (sound sensors) are placed linearly on the surface with the shot point either at one end of the geophone line or in the centre. For refraction, the rebounded waves arrive back at the surface some distance away from the shot point. In reflection, rebounded waves tend to arrive nearby the shot point. Due to this, reflective techniques are the most utilised as less geophones are required to monitor their travel times.

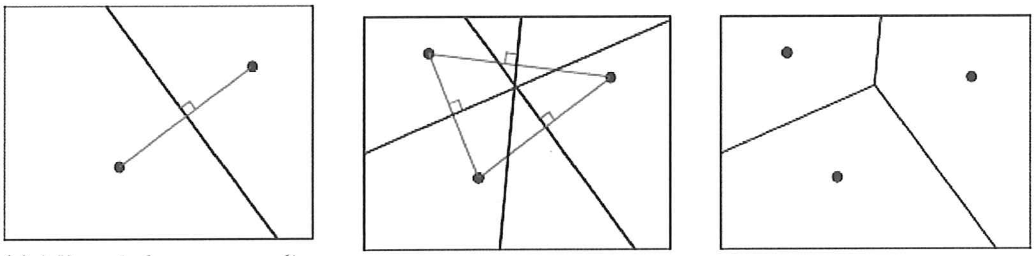
In offshore seismic surveys, dynamite cannot be used as it may be harmful to marine life and it creates air bubbles, which may cause interference on the geophone readings. A variety of shockwave generators are used instead like air guns, water guns and the explosion of combustible gases. Geophones are either trailed on an array behind a boat or placed on the seabed and recovered after the survey has taken place [3].

When the signals arrive at the geophones, they are filtered to ensure that all background noise is emitted. Sections showing similar peaks and troughs are put together in order to show that the signals are originating from the same place. Eventually this produces a contour map showing the reservoir location, dips, lithology and other geological features. This, like other data gathering techniques, is not completely accurate as true representations can only be obtained once drilling has commenced [3].

6.2 Voronoi Grids (PEBI Grids)

Voronoi (Perpendicular Bisection) grids arise when grid points are connected via straight lines, which are then perpendicularly bisected (Figure 9). Due to their flexibility, Voronoi grids have many advantages including: modelling complex geological structures, representing areas near wells and implementing local refinement. They may also be used to construct hybrid grids consisting of hexagonal, Cartesian and curvilinear elements. These features allow Vor~~n~~onoi grids to give a more natural representation to reservoir structures in comparison to the block-centred and corner point methods. However, Voronoi grids have been known to be complex due to the fact they result in a number of Jacobian matrices in comparison to other gridding techniques [6].

What do you mean?



(a) A Voronoi edge as a perpendicular bisector.

(b) Three perpendicular bisectors.

(c) Resulting Voronoi Diagram.

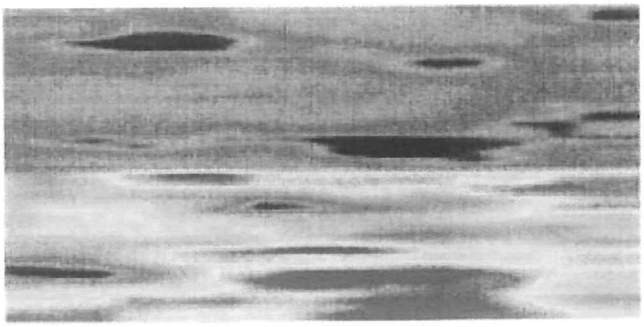
Figure 8 - Construction of a Voronoi Grid [7].

It is important to select the most suitable gridding structure for the reservoir as this drastically affects the final model. These decisions are normally made when the simulator to be used is known.

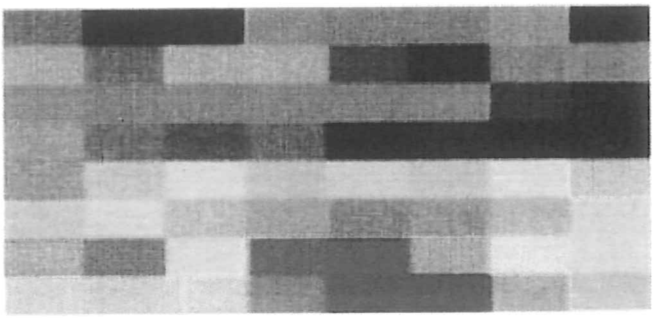
Structured / Unstructured => mesh grid types: quad, triang (2D); hex, tets, pyramids, etc (3D)

7. Upscaling

Models are run numerous times during reservoir simulation so it is of utmost importance to decrease the time taken to run a model. Upscaling is the process of transforming fine grids to coarse grids (Figure 9) to reduce the load on CPUs and remove unnecessary detail. Engineers may choose from a wide range of upscaling techniques depending on the accuracy and time factors.



(a)



(b)

Figure 9 - (a) fine 128x128 grid pre-upscaling; (b) coarse 8x8 grid post-upscaling [8]

7.1 Single-Phase Upscaling

Single-phase upscaling is the most basic type of upscaling available. The main objective is to determine an effective permeability that gives the same total single-phase liquid flow in the coarse gridblock as the result found in the fine gridblock. Numerous methods of single-phase upscaling methods exist, for this report, only a few will be regarded.

7.1.1 Pressure-Solver Methods

In pressure-solver methods, a cube with specific boundary conditions is defined. The effective permeability obtained is based on the assumptions made relating to the boundary conditions. Directional effective permeabilites may be found by solving Darcy's (equation 1) via a matrix composed of the no flow boundary assumption. The inlet and outlet pressures of the cube are set to 1 and 0 respectively which results in a number of fluxes. These fluxes are totalled and the effective permeability is found by

?? What do you mean?

what cube?

equation 2. This technique is simple compared to other methods but has be known to be effective.

$$\nabla \cdot k(\vec{x})\nabla p = 0 \qquad (1)$$

$$k_e^x = -\mu \Delta x Q / A \qquad (2)$$

Where, k = permeability, k_e^x = effective permeability in the x direction, Q = total flow, A = cube area, μ = dynamic viscosity, Δx = cube thickness, p = pressure. ?

By defining boundary conditions that vary with time, full-tensor effective permeabilites may be determined. The results obtained are more accurate than constant boundary conditions but are used less often due to incapabilities with commercial reservoir simulators [8].

or COMPATIBILITIES?

7.1.2 Renormalisation Techniques

Renormalisation involves splitting a large problem in to smaller, more manageable problems. As can be seen in Figure 10, this is implemented in to upscaling by taking small sections of fine grids and performing calculations to determine ~~that~~ THE section's effective permeability. Once found, the effective permeability replaces the fine cell section and the process is repeated for another section. Since computers carry out this task, it can be done extremely quickly. However, this method is seen as more of a quick estimate due to the fact the results are less dependable than other techniques.

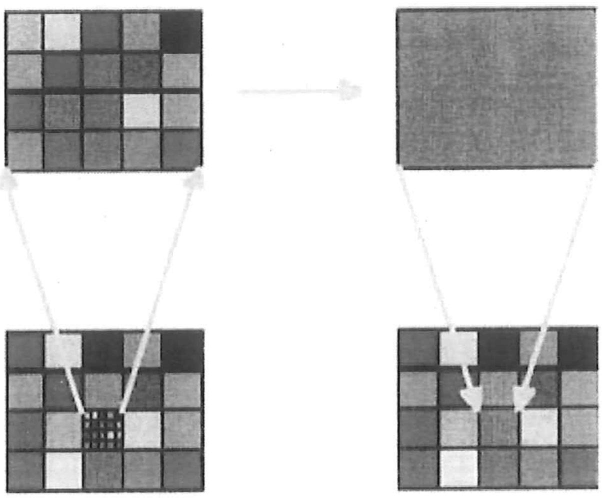


Figure 10 - Renormalisation technique [8]

Other single-phase upscaling techniques are available such as power-law averaging, homogenisation theories, effective medium theory and harmonic/arithmetic mean methods. In comparison to the renormalisation and pressure solver methods, these techniques take less time to solve but are found to be difficult to apply to certain problems [8].

7.2 Two-Phase Upscaling

Although most reservoirs are comprised of two-phases, single-phase upscaling is the most popular in industry. This is in part due to labour intensity of two-phase upscaling and the fact that the permeability results obtained are questionable [9].

Renormalisation may be used in two-phase upscaling but the difference is that a flow simulation is carried out at each level for each cell. This results in an incredible amount of data requiring a vast amount of storage and time. Although Figure 11 shows that the results may sometimes give a more accurate representation to the physical reservoir, the time taken to carry out the process is deemed unworthy. COLLOQUIAL!

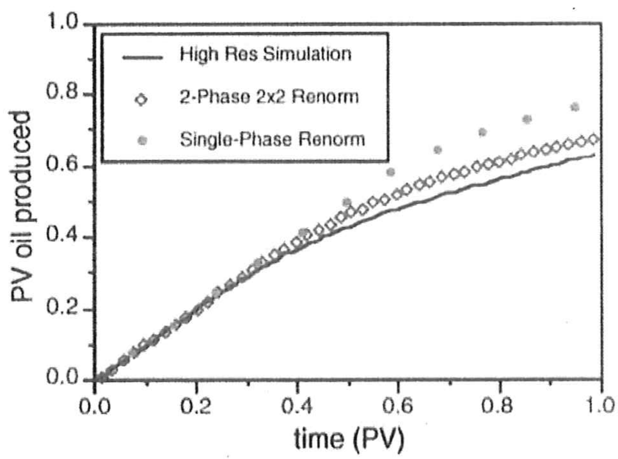


Figure 11 - Comparison of two-phase and single-phase upscaling data obtained from renormalisation [8].

8. Fluid Model

Geological data may be obtained from well logging, coring and seismic analysis but up until this point little has been said concerning the fluids in the reservoir. During the gathering of geological data, instruments are also sent down to collect fluids, which are then sent to the lab to obtain data such as viscosity, density and compressibility, which is vital when carrying out the simulation. Reservoir fluids may also be sorted in to 5 different categories called the Cronquist Reservoir Types: black oil, gas condensate (retrograde gas), volatile oil, wet gas and dry gas [10].

Component	Dry Gas	Wet Gas	Gas Condensate	Volatile Oil	Black Oil
CO_2	0.10	1.41	2.37	1.82	0.02
N_2	2.07	0.25	0.31	0.24	0.34
C_1	86.12	92.46	73.19	57.60	34.62
C_2	5.91	3.18	7.80	7.35	4.11
C_3	3.58	1.01	3.55	4.21	1.01
iC_4	1.72	0.28	0.71	0.74	0.76
nC_4	-	0.24	1.45	2.07	0.49
iC_5	0.50	0.13	0.64	0.53	0.43
nC_5	-	0.08	0.68	0.95	0.21
C_6s	-	0.14	1.09	1.92	1.16
C_{7+}	-	0.82	8.21	22.57	56.40

Floating Table!

~~Figure~~ TABLE 12 - Typical mol% compositions of Cronquist reservoir fluid types [10]

In a dry gas reservoir (Figure 13a), the temperature is significantly above the cricondentherm and so falls in to the vapour region. Due to the fact that the production path does not enter the phase envelope, no liquid phase is observed hence the name "dry gas". In industry, the pressure inside storage tanks is usually sufficient to enter this phase envelope and thus result in a small liquid phase. From Figure 11 it can be seen that dry gas is mainly comprised of methane with a complete disregard for heavy hydrocarbons. Table 12

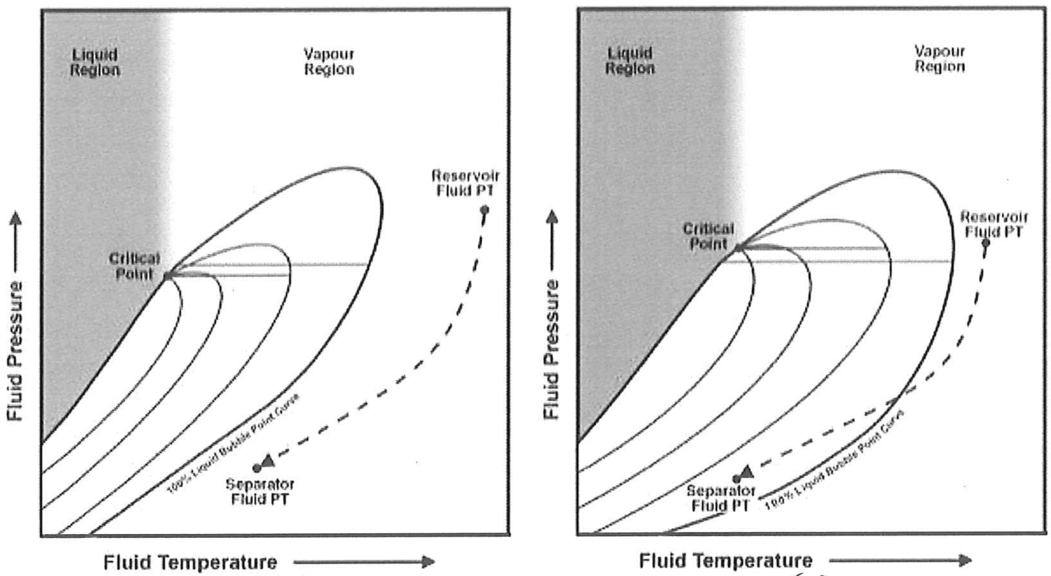
Wet gas reservoirs (Figure 13b) exist at a temperature, which is slightly above the cricondentherm in the vapour region. During production, unlike dry gas reservoirs, the phase envelope is entered and a liquid phase is seen. Like dry gas, wet gas is almost PE entirely composed of methane with small amounts of heavier hydrocarbons.

Volatile oil reservoirs (Figure 14a) usually consist of a liquid and vapour phase in equilibrium due to being inside the phase envelope. As production proceeds, the vapour fraction decreases causing a higher presence of heaver hydrocarbons in the liquid phase.

In black oil reservoirs (Figure 14b) only a liquid phase is present due to the fact that the temperature is lower than the critical point but the pressure is larger than the cricondenbar. During production, a decrease in pressure means that the phase envelope

PE is entered. The bubble point line is then reached causing a small vapour phase to be formed. This gas has little impact on the overall composition as the large liquid phase results in a heavy hydrocarbon dominance. Nb

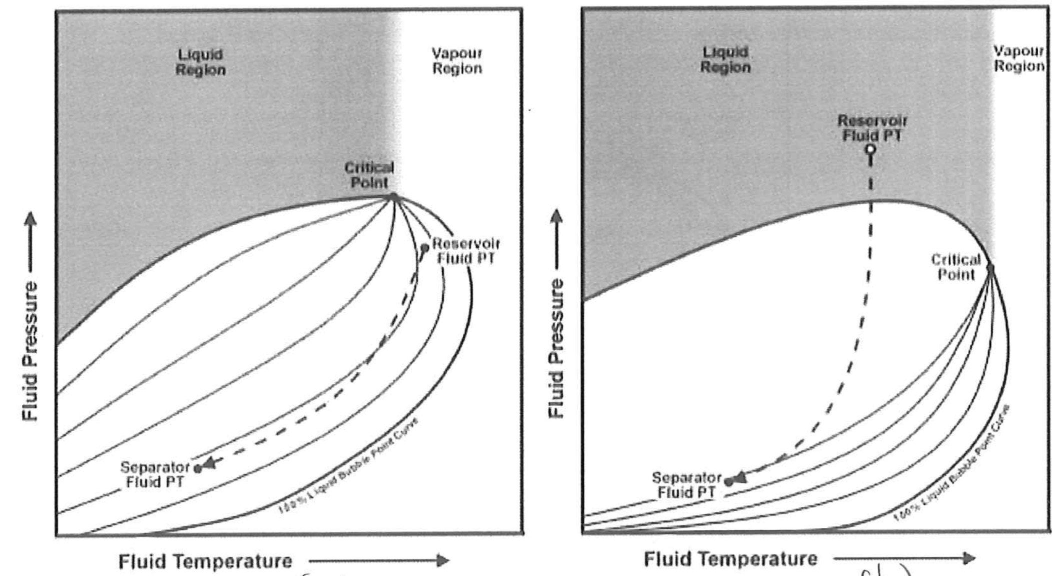
Gas condensate reservoirs (Figure 15) are at a temperature that is lower than the cricondentherm but higher than the critical point. As the vapour expands during production, the temperature and pressure decrease, causing the dew point to be reached. From this point, more and more liquid is condensed from the vapour phase. In ~~Figure~~ Table 12 ~~11~~ it can be seen that a gas condensate is mainly composed of methane but has a larger fraction of denser hydrocarbons when compared to wet and dry gas reservoirs [10].



poor quality!

(a) (b)

Figures 13 (a) & (b) - PT phase diagrams for dry gas & wet gas respectively [10]



(a) (b)

Figure 14 (a) & (b) - PT phase diagrams for volatile oil & black oil respectively [10]

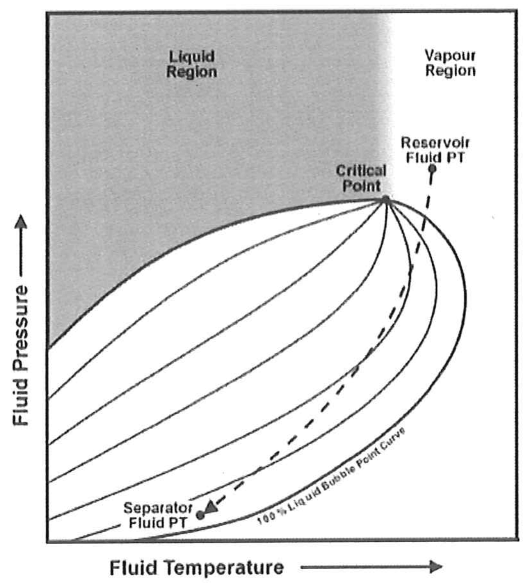


Figure 15 - PT phase diagram for gas condensate [10]

Not only geological data. Also fluid data!

9. Simulators

Reservoir simulators are computer modelling software that take inputs such as the geological data to predict the fluid flow through porous media. A vast number of reservoir simulators are available with academic models developed by educational institutions and commercial models made by companies. Companies may choose to develop their own simulators for reasons such as gaining an advantage over rival

?

companies, dealing a different type of reservoir or so that they can easily add technological enhancements. For the purpose of this report, only a brief number of simulators will be discussed.

9.1 Simulation Model Types

(brief but very superficial!)

The most popular simulation model types are thermal, black oil, chemical flood and compositional.

A black oil model is the most basic as it will not take in to consideration changes in composition by making assumptions like there is no oil dissolved in the water phase.

In compositional models, the equations of state such as Peng-Robinson and Soave-Redlich-Kwong are used to monitor the compositions and phase changes in the reservoir, thus making the compositional model more accurate than the black oil model. This however comes at a price as the compositional model takes considerably longer and costs more to run than the black oil model.

Thermal models allow for the simulation of EOR (enhanced oil recovery) techniques involving temperature changes such as steam injection and STRIP (Solvent Thermal Resource Innovation Process).

Chemical flooding models predict the behaviour of the reservoir during a process called chemically enhanced oil recovery in which a combination of chemicals are injected in to wells to retrieve residual oil [11].

9.2 ECLIPSE (Schlumberger)

ECLIPSE is a reservoir simulator developed by the Schlumberger software division GeoQuest with new versions coming out annually. It utilises ~~the~~ finite volume method to perform black oil, compositional, thermal and streamline simulations. ECLIPSE is combined with the Petrel software package, which carries out history matching, gridding, optimisation of well locations and reservoir recovery methods. Versions of ECLIPSE include ECLIPSE 100, which carries out black oil simulations on corner point grids, and ECLIPSE 300, which carries out compositional and thermal simulations [12]. ECLIPSE is also able to simulate unconventional reservoirs (coalbed methane, shale oil) and chemical enhanced oil recovery techniques [13].

6. Grid Generation

To model the changing properties in a reservoir, the entire volume is split in to thousands to millions of cells that are represented by either block centred, corner point or Vornonoi geometries. Parameters are then assigned to these cells where computational techniques are used to determine properties in neighbouring cells, by modelling the fluid flow in the reservoir.

6.1 Corner Point and Block Centred Geometry

EXCELLENT!

The co-ordinates for block centred geometry are defined by the centre of the block whereas the co-ordinates for corner pointed geometry are given by the corners (Figure 7). This is advantageous for corner point geometry as this allows for cell shapes to be less restricted, meaning that geological features in the reservoir such as faults and dips may be modelled with greater accuracy. In corner point geometry, properties such as pressure, velocity, permeability etc. are ~~put on to~~ ALLOCATED AT each corner of the cell whereas in block centred geometry, these properties are located on a single point inside the cell ~~centre~~. This means that more information is available in the corner-point method as properties vary from corner to corner rather than just having a single property value per cell. Corner-point geometry does have its drawbacks through as the large number of specified points adds complexity. Due to this engineers prefer to use block-centred grids for ease and familiarity.

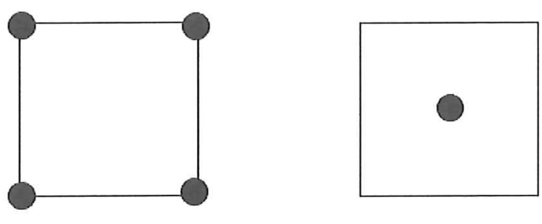


Figure 7 - Basic representation of corner point (left) & block centred (right) geometries

When areas of specific interest or regions that cannot be accurately depicted by the cell size are encountered in a reservoir, local grid refinement may take place. This involves dividing cells in to smaller sections to obtain the required accuracy.

? You haven't explained this yet!

9.3 EM^{power} (ExxonMobil)

Developed during the late 1990's, the EM^{power} simulator is the result of the amalgamation of two state of the art technologies from ExxonMobil. EM^{power} can use considerably more geological data than other simulators due to the fact it may carry out calculations in unstructured grids. By implementing unstructured grids, the simulator is able to model complicated geological features (e.g. sloping faults and fluid contacts) more accurately than simulators using rectangular or regular grids. Another advantage is the fact that several fields connected via a common production structure may be dealt with in the same single model [14].

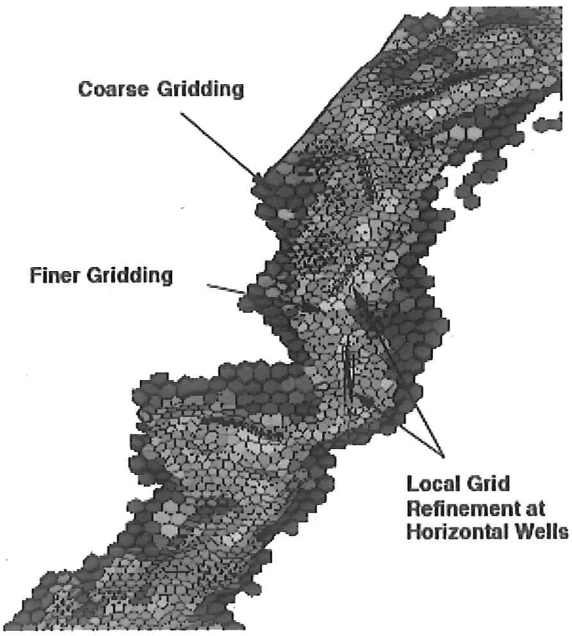


Figure 16 - Screenshot of EM^{power} simulation showing coarse & fine gridding on an unstructured grid [14]

9.4 POWERS (Saudi Aramco)

In the Middle East, giant oil/gas fields are a regular occurrence. For reservoirs to be accurately modelled, grid blocks need to be about 25 to 50 metres in length. When grid blocks these size are implemented in the giant Middle East fields, it yields about a billion cells .Traditional reservoir simulators are usually only able to deal with a maximum of a million cells which results in a loss of accuracy as shown in Figure 17 [15]. In 1992 Saudi Aramco developed their first reservoir simulator called POWERS (Parallel Oil Water and Gas Reservoir Simulator), which was capable of dealing with cells in the magnitude of millions. However, as larger and larger fields were discovered it became evident that the models produced by POWERS were insufficient so it was developed in to GigaPOWERS, a parallel simulator with the ability to accurately run models consisting of over a billion cells [16].

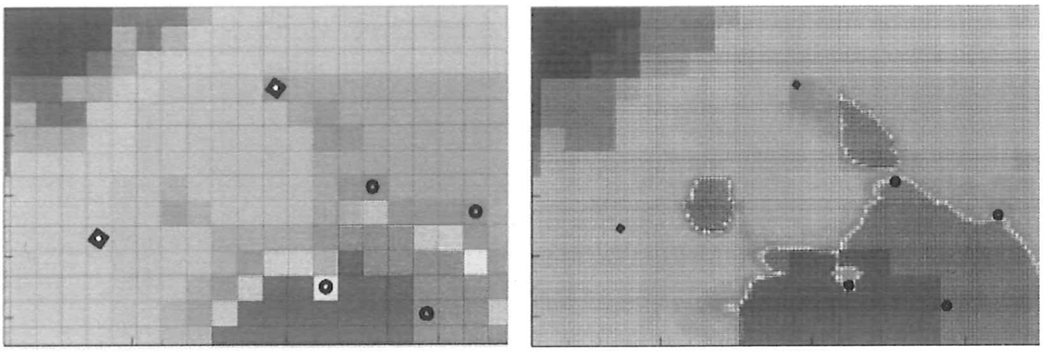


Figure 17 - Million cell model (left) & billion cell model (right) [15]

9.5 Open Source Models

Open source reservoir simulators exist so that they may be used academically or modified to fit one's own means. An example of this is MRST (MATLAB Reservoir Simulation Toolbox), which uses the corner-point method in structured and unstructured grids while implementing basic flow and transport solvers [17]. Other examples include BOAST (Black Oil Applied Simulation Tool) and OPM (Open Porous Media).

colloquial!

The beauty of open source software is that people may create add-ons to deal with specified scenarios. They may be less complicated than commercial simulators but they allow researchers to make progress with regards to the development of new technology in the field of reservoir engineering.

10. History Matching

The geological data obtained from cores and logs only give information relating to a tiny volume of the entire reservoir. In order to gain a more accurate simulation on a larger scale, history matching is implemented. This is the manipulation of initial model parameters while considering historical reservoir performance data to ensure that the model gives a greater representation of the physical reservoir. Known as an extensive process, this stage may take over half of the whole reservoir simulation time as it relies on iteration, skill and judgement. There are numerous methods to conduct history matching with non-automatic methods usually favoured due to the limited success of automatic procedures [18].

10.1 Strategies

Many different approaches exist in history matching with ~~Figure 17~~ Table 17 depicting a generalisation of a typical strategy. Steps 1 and 2 are given priority over the last two and must be met. Due to factors such as inaccurate geological data, poor model selection and a poorly characterised reservoir, the first two steps may not be met which means that amendments are essential.

Step	Remarks
1	Match volumetrics with material balance and identify aquifer support.
2	Match reservoir pressure. May be done globally, locally or both.
3	Match saturation dependant variables e.g. water-oil ratio (WOR) and gas-oil ratio (GOR)
4	Match well flowing pressures

Figure 18 - General history matching structure [18]

For black oil and gas models, GOR, WOR, production rate and pressure are matched. Compositional and thermal models require more ~~specified~~ SPECIFIC data such as well stream composition and produced fluid temperature.

Initially, the pressure of the model may be compared to uncorrected historical pressures for an estimation. Corrected historical pressures may be utilised during the process of fine-tuning the model. Model production rates are compared with the physical rates from the reservoir usually by viewing each resultant curve in a technique called decline-curve analysis (see section 10.2).

In order to match model data to historical data, input parameters have to be modified. The rule of thumb is that the most unreliable data is changed during history matching. The most commonly altered parameter is the relative permeability due to the fact that this data is usually obtained purely from cores, which does not give an accurate representation for the whole reservoir. Relative permeability data, along with porosity data are usually modified in order to aid in pressure matching. The next set involves matching saturation dependant data like WOR and GOR. This depends on the type of fluid present in the reservoir, e.g. dry gas reservoirs only comprise of gas whereas black oil reservoirs contain a high fraction of liquid and a small fraction of gas. As pressure is given precedence over saturation dependant properties, the relative permeability data cannot be significantly altered. Due to this, zone thickness and absolute permeability are often changed to match WOR and GOR values [18].

It must be noted that these altered parameters must be changed within reason; changing values to unrealistic physical representations will result in a poor simulation.

10.2 Decline-Curve Analysis (Arp's Technique)

In industry, many simulators like ECLIPSE and EM^{power} have integrated history matching software that carries out the work automatically. However, many engineers feel that this is not a worthy substitute to human judgement and experience so manual techniques are still popular. A common manual technique is Arp's decline-curve analysis. Arp's decline-curve analysis is a procedure in which the well production data is fitted to one of three curves: hyperbolic, exponential or harmonic (Figure 18). For Arp's technique to hold the well must be in pseudosteady-state (constant decline of reservoir pressure as the well is drained) for both the production time being modelled by the engineer and the production life that is to be predicted [19]. The curve is found by using equation 3.

FONT

$$\frac{1}{q}\frac{dq}{dt} = bq^{d} \tag{3}$$

Where, t = time, q = the flow rate at time t, b = empirical constant found from the production data, d = Arp's decline-curve exponent (for an exponential curve d=0, for a hyperbolic curve 0<d<1, for a harmonic curve d=1).

$$\int q^{d-1}\,dq = \int b\,dt$$

if $d=0$: $\ln q + C_1 = bt + C_2$

if $d\neq 0$: $\frac{q^d}{d} + C_1 = bt + C_2$

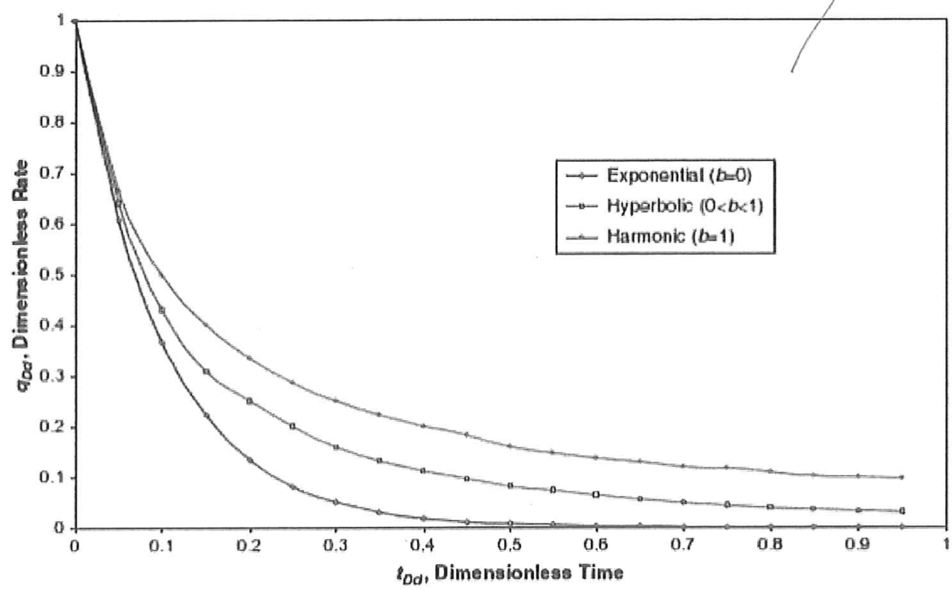


Figure 19 – General curve shapes of Arp's technique [20]

11. Future Work

Too colloquial

From this literature review I was able to appreciate reservoir simulation as a whole and for my thesis I was tasked to cover a certain stage in the workflow to perform an in-depth analysis. As I am a chemical engineer, I thought it best to concentrate on the "Fluid Model" stage as phase envelopes and PVT data are prospects that I am familiar with. I am to go in to detail with regards to the equations of state, fluid properties and methods to monitor/asses reservoir fluids. Full details of my thesis assignment are not available yet but it may also include using UniSim or a similar program to simulate fluid phase equilibria subjected to different conditions.

↳ But what are the plan???

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Appendix C:

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I confirm that I have read, understood and will abide by the University statement on cheating and plagiarism as provided in the Academic Quality Handbook, and I have been made aware of how to correctly reference materials in all my submitted work, including my Honours project thesis.

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