UNIT IV

Design and implementation of a multiphase flow reservoir simulator, including interphase mass transfer and variable fluid saturation pressure. Design of compositional reservoir simulators using generalized equation of state. Recent advances in reservoir simulation.

DESIGN AND IMPLEMENTATION OF A MULTIPHASE FLOW RESERVOIR SIMULATOR

Modeling fluid flow in a porous medium is a challenging computational problem. It involves highly heterogeneous distributions of porous medium property, various fluid flow characteristics. For the design of better flow management scheme, high performance computing tools have been applied as a useful technique. In this paper, various parallel implementation approaches are introduced mainly based on high performance computing toolkits such as ADIFOR, PETSc, and Cactus.

Provided by ADIFOR, accurate Jacobian matrix computation scheme was coupled with PETSc (Portable Extensible Toolkit for Scientific Computation), which allows data structures and routines for the scalable solution of scientific applications modeled by partial differential equations. In addition to the PETSc-ADIFOR-based approach, we also present a methodology to apply a grid-enabled parallel implementation toolkit, Cactus for the simulation of fluid flow phenomena in porous media. The preliminary result shows a significant parallel performance. On the basis of the current result, we further discuss the future plan for the design of multi-purpose porous media flow simulator.

Parallel computing technology has been exploited in various fields of science and engineering areas. As addressed in many textbooks, the basic issues of parallel scientific computing are well identified. However, this does not mean that robust solutions are always available through the use of large computing power. Our particular motivation is to utilize advanced computational techniques to address the fundamental issues of solution approaches involved with modeling multiphase fluid flow in porous media

Coupled with Darcy's law, the governing equations of the fluid flow in porous media are derived by mass and energy balances, which are resulted in a set of coupled partial differential equations (PDEs). Various numerical approaches such as finite difference, finite volume, and finite element methods are used to obtain the solution over the discretized PDE domain.

The most popular method to solve such discretized PDE systems is the Newton's method. It requires a Jacobian matrix system to seek solution increments. The easiest and most widely used method for the Jacobian matrix computation is divided-differentiation method (or called finite difference scheme, FD), which

obtains the derivatives by dividing the response perturbation of a functional calculation to the step-size variation of an independent variable.

This method can lead to the breakdown of Newton iterations if high nonlinearity of a functional calculation generates a significant round-off and truncation errors. Automatic differentiation (AD) method provides attractive alternative method for accurate and efficient Jacobian matrix computation. We explain how to couple the AD method in the parallel implementation procedure of a multiphase flow code. We used the SNES and SLES components of PETSc for the robust and flexible parallelization of the flow modeling code.

Additionally, we initialized an effort to implement a multiphase flow modeling system in a grid computing environment. Different from conventional computing frameworks, the grid computing technology enables large-scale aggregation and sharing of computing, data and other resources across geographical boundaries. This provides a new simulation approach to develop a next generation model of dynamically interactive, data-driven modeling strategies for application scientists.

For an example, fine-resolution reservoir flow simulation models can be integrated with various observed data types derived from seismic/downhole sensors deployed in reservoir fields. This will eventually make it possible to establish an instrumented virtual operation systems providing more efficient, cost-effective, and user-friendly reservoir flow management schemes. In this paper, we explored to use this new grid-enabled approach to implement a multiphase flow modeling code using a grid middleware package, Cactus Computational Toolkit [4]. Through this demonstration, a prototype can be established to identify new grid application projects in computational fluid flow or other large scale simulation areas. Following the description of the model problems, we discuss the parallel implementation algorithms of both PETSc and Cactus and the test result of the implemented codes.

INTERPHASE MASS TRANSFER AND VARIABLE FLUID SATURATION PRESSURE

(i) Interphase Mass Transfer

The process of mass transfer from the bulk of one phase to the interphase surface and then from the interphase to the bulk of another phase is called interphase mass transfer. As an example absorption of sulfur dioxide from air occurs by water. In this case sulfur dioxide diffuses through air and then passes through the interface between the air and water and finally, diffuses through the adjacent immiscible water phase. Here mass transfer occurs in each phase because of concentration gradient till an equilibrium state (i.e., chemical potential of the component becomes same for both the phases) exists at the interface between the phases. When a system is in equilibrium, there is no net mass transfer between the phases. In cases involving ideal gas and liquid phases, the fairly simple useful

relation (Equation (1)) known as Raoult's law can be applied for relating the equilibrium concentrations in the two-phases.

$$y_A P = x_A P_A^v \text{ .....(1)}$$

where P_A^v is the vapour pressure of pure solute A at the equilibrium condition and P is the equilibrium pressure. If the liquid phase does not behave ideally, the following modified form of Raoult's law can be applied:

$$y_A P = x_A P_A^v \gamma_A \text{ .....(2)}$$

where γ_A is the activity coefficient of solute A in solution. For dilute solution Henry's law can be used to express the equilibrium relations which is expressed by $P_A = y_A P = H x_A$

where pA is the equilibrium partial pressure of solute A in the vapour phase and H is the Henry's law constant.

A level set approach is applied for simulating the interphase mass transfer of single drops in immiscible liquid with resistance in both phases. The control volume formulation with the SIMPLEC (semi-implicit method for pressure-linked equations consistent) algorithm incorporated is used to solve the governing equations of incompressible two-phase flow with deformable free interface on a staggered Eulerian grid. The solution of convective diffusion equation for interphase mass transfer is decoupled with the momentum equations. Different spatial discretization schemes including the fifth-order WENO (weighted essentially nonoscillatory), second-order ENO (essentially nonoscillatory) and power-law schemes, are tested for the solution of mass transfer to or from single drops. The conjugate cases with different equilibrium distribution coefficients are simulated successfully with the transformation of concentrations, molecular diffusivities, mass transfer time and velocities. The predicted drop concentration, overall mass transfer coefficient and flow structure are compared with the reported experimental data ofa typical extraction system, i.e., n-butanol–succinic acid–water, and good agreement is observed.

Interphase mass transfer occurs when mass is carried from one phase into another. It is applicable to both the inhomogeneous and homogeneous multiphase models. Some of the model libraries available in CFX-Pre contain simulation definitions for interface mass transfer cases, including boiling water and cavitation.

Possible causes of interphase mass transfer are:

- Change of thermodynamic phase. For example, melting/solidification in liquid-solid systems, evaporation/condensation in gas-liquid systems, and cavitation in gas-liquid systems.

- Diffusion of a dissolved species across a phase boundary. This may or may not involve a change of phase of the dissolved species. Examples are gas dissolution, and evaporation of a liquid into a gas containing its vapor.
- Breakup and coalescence may be treated as a mass transfer process between two phases representing different size groups of the same species.

(ii)Variable Fluid Saturation Pressure

The saturation vapor pressure is the pressure at which fluid passes from the gaseous to liquid state (or from liquid to gas) for a given temperature. If the fluid temperature increases, the pressure at which fluid passes from liquid to gas (saturation vapor pressure) increases. Thus a liquid like water can turn into steam at ambient pressure by supplying heat, but it is possible to make this transformation without changing the temperature by lowering the ambient pressure below the vapor pressure saturation.

When the liquid is sucked into a pipe a pressure drop is created, if this downward pressure is lower than the saturation vapor pressure, the liquid begins to boil. (Steam), this phenomenon is called cavitation. The saturation vapor pressure _is a formation of vapor bubbles due to pressure drop. In forming these bubbles increase the volume of fluid present in the area of low pressure which in effect increase the pressure in certain places where gas bubble condenses violently imploding. The shocks created by the bursting of bubbles destroy the walls of the organs in contact with the fluid. Cavitation quickly wears pump .

Calculation of the saturation vapor pressure

The approximate calculation of the saturation vapor pressure can be done using the Clapeyron equation, taking as hypotheses - among others - that the vapor behaves as an ideal gas and the enthalpy vaporization does not vary with temperature in the range considered.

$$\ln \frac{P_{sat}}{P_0} = \frac{M.L_v}{R}(\frac{1}{T_0} - \frac{1}{T})$$

with:

T 0 : Boiling temperature of the substance at a pressure P 0 given K

P sat : Saturation vapor pressure in the same units as P 0

M: molar mass of the substance, kg / mol

L v : Latent heat of vaporization of the substance, J / kg

R: gas constant, equal to 8.31447 J / K / mol

T: steam temperature, K

For water, for example:

M = 0.018 kg / mol

L v = 2.26 × 10 6 J / kg

P 0 = 1013 mbar

T 0 = 373 K

DESIGN OF COMPOSITIONAL RESERVOIR SIMULATORS USING GENERALIZED EQUATION OF STATE

Equation-of-state (EOS) compositional reservoir simulation is an accurate and powerful means to model complicated phase and flow behavior involved in the displacement of oil and gas in porous media. The use of EOS simulation becomes even more effective when the process involves solvent injection for miscible or near-miscible displacement of crude oil in reservoirs. The current trend of combining the simulation of reservoirs and surface facilities increases the demand for the use of EOS compositional models. One key to proper use of compositional simulators is development of an EOS for describing the phase behavior of the fluids.

A procedure for solving compositional model equations is described. The procedure is based on the NewtonRaphson iteration method. The equations and unknowns in the algorithm are ordered in such a way that different fluid property correlations can be accommodated leadily. Three different correlations have been implemented with the method. These include simplified correlations as well as a Redlich-Kwong equation of state (EOS). The example problems considered are (1) a conventional waterflood problem, (2) displacement of oil by CO, and (3) the displacement of a gas condensate by nitrogen. These examples illustrate the utility of the different fluid-property correlations. The computing times reported are at least as low as for other methods that are specialized for a narrower class of problems.

Black-oil models are used to study conventional recovery techniques in reservoirs for which fluid properties can be expressed as a function of pressure and bubble-point pressure. Compositional models are used when either the pressure. Compositional models are used when either the in-place or injected fluid causes fluid properties to be dependent on composition also.

Examples of problems generally requiring compositional models are primary production or injection processes (such as primary production or injection processes (such as nitrogen injection) into gas condensate and volatile oil reservoirs and (2) enhanced recovery from oil reservoirs by CO or enriched gas injection. With deeper drilling, the frequency of gas condensate and volatile oil reservoir discoveries is increasing. The drive to increase domestic oil production has increased the importance of enhanced recovery by gas injection. These two

factors suggest an increased need for compositional reservoir modeling. Conventional reservoir modeling is also likely to remain important for some time.

In the past, two separate simulators have been developed and maintained for studying these two classes of problems. This result was dictated by the fact that compositional models have generally required substantially greater computing time than black-oil models.

The approach is based on the use of explicit problems. The approach is based on the use of explicit flow coefficients. For compositional modeling, two basic methods of solution have been proposed. We call these methods "Newton-Raphson" and "non-Newton-Raphson" methods. These methods differ in the manner in which a pressure equation is formed. In the Newton-Raphson method the iterative technique specifies how the pressure equation is formed.

In the non-Newton-Raphson method, the composition dependence of certain ten-ns is neglected to form the pressure equation. With the non-Newton-Raphson pressure equation. With the non-Newton-Raphson methods, three to eight iterations have been reported per time step. Our experience with the Newton-Raphson method indicates that one to three iterations per tune step normally is sufficient. In the present study a Newton-Raphson iteration sequence is used. The calculations are organized in a manner which is both efficient and for which different fluid property descriptions can be accommodated readily.

Early compositional simulators were based on K-values that were expressed as a function of pressure and convergence pressure. A number of potential difficulties are inherent in this approach. More recently, cubic equations of state such as the Redlich-Kwong, or Peng-Robinson appear to be more popular for the correlation Peng-Robinson appear to be more popular for the correlation of fluid properties.

The most common EOS used in reservoir simulation are the PR and the SRK models. Both models have two constants, a and b. Each constant must be calculated for each component based on component critical properties (T_c and p_c) and acentric factor (ω).

The PR EOS has two versions—the original 1976 version and the modified 1979 version the latter uses a third-degree polynomial expression for the correction term to constant a. For some systems, the difference in equilibrium calculations for the two PR EOS models is significant.

The Peneloux volume shift factors should always be used with two-constant EOS models to ensure accurate oil and gas densities. The volume shift factors have no impact on calculated K-values or compositions, only densities. As mentioned earlier, the ZJRK , EOS is outdated and was used before the volume-shift method

was introduced in 1980, with complex correction functions to constants a and b to improve liquid density predictions.

Binary interaction parameters (BIPs) k_{ij} are important for adjusting predictions of equilibrium properties (K-values and compositions). These parameters represent a correction of the form $(1 - k_{ij})$ to the $a_i a_j$ term in the quadratic mixing rule for EOS constant a. BIPs can be positive or negative; they are symmetric ($k_{ij} = k_{ji}$); they are usually ~0 for most hydrocarbon-hydrocarbon pairs, except C_1 to C_{7+} pairs which may reach values as high as 0.25; and they are generally close to 0.1 for nonhydrocarbon (N_2, CO_2, H_2S)-hydrocarbon pairs.

(i)Black-oil PVT models

Black-oil PVT properties are generated in one of two ways. For low- to medium-gas-oil-ratio (GOR) oils (< 150 Sm^3/Sm^3), a traditional differential liberation experiment (DLE) is used, with corrections for separator flash to calculate oil formation volume factor (FVF) B_o and solution GOR R_s, as well as the gas FVF B_g. This approach assumes the reservoir gas contains unsubstantial amounts of condensate in solution, with solution oil/gas ratio r_s ~ 0.

The more common and general approach to generating black-oil PVT properties uses an EOS model to simulate a depletion-type PVT experiment (differential liberation, constant volume depletion, or constant composition expansion), with the equilibrium gas and equilibrium oil at each stage in the depletion being individually processed to surface conditions to provide the four black-oil properties

- B_o
- R_s
- B_g
- r_s

For highly volatile oils, the EOS method gives substantially different and improved black-oil properties compared with the traditional laboratory DLE/separator-corrected approach.

The conversion of black-oil PVT data (R_s, B_o, r_s, and B_g) to a compositional model uses K-values of surface gas and oil pseudo "components" $K_{gs} = (R_s + C_{os}) / (1 + r_s C_{os}) / R_s$ and $K_{os} = r_s(R_s + C_{os}) / (1 + r_s C_{os})$, with $C_{os} = (RT_{sc} / p_{sc})(\rho_{os} / M_{os})$. The reservoir-phase densities are calculated from $\rho_g = (\rho_{gs} + \rho_{os} r_s) / B_g$ and $\rho_o = (\rho_{os} + R_s \rho_{gs}) / B_o$, while phase molecular weights are given by $M_g = (M_{gs} + r_s M_{os} C_{os})/(1 + r_s C_{os})$ and $M_o = (R_s M_{gs} + M_{os} C_{os}) / (R_s + C_{os})$. Viscosities and gas/oil IFTs are interpolated directly from input tables.

Coats *et al.*, Coats *et al.*, and Fevang *et al.* have shown that black-oil models can be used for practically any type of reservoir produced by depletion or waterflooding, including reservoirs with large compositional gradients. Some issues require special treatment for complex fluids systems, including fluid initialization and the method for generating black-oil tables. In a nutshell, the recommended procedures are to generate the black-oil tables with an EOS model using the fluids with the highest saturation pressure (e.g., at the gas/oil contact) and to initialize with solution GOR ($R_s$and r_s) vs. depth—not saturation pressure vs. depth.

A common problem with black-oil models is the calculation of "negative compressibility," meaning that a small pressure drop results in a reduction in total (gas + oil) volume. Another problem is physical extrapolation of saturated PVT properties to saturation pressures higher than given in the input table (e.g., caused by gas injection, gravity segregation in undersaturated reservoirs, or near-well behavior during rate reductions).

When can the black-oil PVT treatment not be used? Basically, for any gas-injection process with significant component partitioning that changes during the displacement. This would include processes with high-pressure vaporization using lean gas, condensation from enriched injection gas, and developed-miscibility processes such as the condensing/vaporizing mechanism. Surprisingly, a black-oil treatment is sometimes adequate even for complex gas injection problems, though it is not usually known *a priori*. To check the validity of a black-oil model in a gas injection project, the reservoir process should first be simulated with a compositional model, and preferably a relevant 3D model that captures all important flow characteristics.

(ii)Three-phase PVT behavior

Three-phase (L1-L2-V) behavior is an occasional but serious problem for EOS-based compositional models. The third phase (L2) is usually a light liquid and typically appears at low temperatures (< 140°F) in gas-injection processes using CO_2 or NGL-enriched gas.Physically, three phases may actually exist, and the EOS model is correctly predicting the behavior. Sometimes a three-phase system is predicted without one physically existing; this may result for lower temperatures when the heaviest component properties are improperly modified to fit two-phase gas/oil PVT data.

For reservoir simulators, the three-phase problem is caused by the EOS formulation "allowing" only two phases. If three phases actually exist, the two-phase flash may find any of the three possible two-phase combinations: L1-V, L2-V, or L1-L2. These false two-phase solutions may indicate a single-phase condition, or they may actually appear as a valid solution (meeting the equal fugacity constraints). Unfortunately, the reservoir model, in a given cell during a given timestep, may flip-flop between two of the possible solutions, resulting in

unstable behavior because the pressure solution is not continuous from one two-phase solution to the other. Models may have to simply give up because of repeated timestep reductions, which result from the inadequacy of the EOS two-phase model handling a three-phase condition.[35]

(iii)Surface phase behavior

In compositional simulation, the surface calculations are usually made using multistage separation with an EOS model, with fixed *K*-values for each separator, or using so-called "gas plant" factors, which define the fraction of a wellstream component that is processed into the stock-tank oil.

For black-oil models, the surface separation is "built in" to the PVT tables. Consequently, if the surface process changes during a model run, all black-oil PVT tables must be reentered at the appropriate time. This also requires that vertical flow performance (VFP) tables be reentered because surface rate and volume ratio nodes change with the process change.

It is difficult to use traditional black-oil models for fields with various well groups that have significantly different processing facilities.

(iv)Thermal model PVT requirements

Additional PVT requirements for thermal processes such as steamflooding include quantifying the temperature dependence of *K*-values, densities, and viscosities. Water-phase behavior of liquid and steam must also be defined in terms of pressure and temperature. Water-hydrocarbon phase behavior is still assumed to be simple, without water/hydrocarbon component partitioning.

An EOS model can be tuned to distillation data for improving the predictive capabilities of *K*-value dependence; otherwise, a simple correlation of the form $K_i = a_i \exp(-b_i T) / p$ may be used for distillable components. Using distillation data is an indirect approach to defining *K*-value behavior, and it is used in lieu of high-temperature gas/oil/water phase-behavior experiments, which are not usually available. Oil viscosities in thermal processes may be difficult to correlate with a compositional correlation, so empirical correlations may be used instead.

(v)Fluid initialization

As with rock and other petrophysical properties such as permeability and porosity, a reservoir simulator model must also initialize the spatial distribution of initial fluids. For an EOS-based model, the initial molar compositions are defined, $z_i(x,y,z)$. For a black-oil model, the initial solution gas-oil ratio R s and solution oil-gas ratio r s ratio are defined, $R_s(x,y,z)$ and $r_s(x,y,z)$; sometimes saturation pressures are used instead, $p_b(x,y,z)$ and $p_d(x,y,z)$, but this is not recommended. Specifying a saturated gas-oil contact (GOC) is also a means to initialize fluids vertically in a reservoir simulator, where solution GOR R_s (and bubblepoint) are assumed constant below

the GOC, while solution OGR r_s decreases upwards from the GOC to honor the model-imposed assumption that reservoir pressure equals dewpoint pressure, $p(z) = p_d(z)$.

Another fluid initialization data might include temperature $T(x,y,z)$. Some black-oil models allow spatial variation of stock-tank oil density, $\gamma_{API}(x,y,z)$, where black-oil properties are correlated in multidimensional tables as a function of pressure and γ_{API} . Across barriers such as faults and sealing shales, discrete PVT model data may be defined, such as EOS parameters or black-oil tables; such "discontinuous" fluid descriptions may cause physical and model incompatibilities if fluids mix in the reservoir or at the surface.

A typical problem with initialization is that the specified fluid distribution, initial pressure specifications, and fluid contacts lead to fluid movement when the model is turned on (without production or injection). Initial fluid movement may be unimportant without significantly changing the user-specified fluid system; serious inconsistencies may lead to time-zero flow that has an impact on model performance.

RECENT ADVANCES IN RESERVOIR SIMULATION

The recent advances in reservoir simulation may be viewed as:

- Speed and accuracy;
- New fluid flow equations;
- Coupled fluid flow and geo-mechanical stress model; and
- Fluid flow modeling under thermal stress.

(i)Speed and Accuracy

The need for new equations in oil reservoirs arises mainly for frac-tured reservoirs as they constitute the largest departure from Darcy's flow behavior. Advances have been made in many fronts. As the speed of computers increased following Moore's law (doubling every 12 to 18 months), the memory also increased. For reservoir simulation studies, this translated into the use of higher accuracy through inclu-sion of higher order terms in Taylor series approximation as well as great number of grid blocks, reaching as many as a billion blocks. The greatest difficulty in this advancement is that the quality of input data did not improve at par with the speed and memory of the com-puters. As Fig. 1 shows, the data gap remains possibly the biggest challenge in describing a reservoir. Note that the inclusion of large number of grid blocks makes the prediction more arbitrary than that predicted by fewer blocks, if the number of input data points is not increased proportionately. The problem is particularly acute when fractured formation is being modeled. The problem of reservoir cores being smaller than the representative elemental volume (REV) is a difficult one, which is

more accentuated for fractured formations that have a higher REV. For fractured formations, one is left with a narrow band of grid blocks, beyond which solutions are either meaningless (large grid blocks) or unstable (too small grid blocks). This point is elucidated in Fig. 2. Figure 2 also shows the difficulty associated with modeling with both too small or too large grid blocks. The prob-lem is particularly acute when fractured formation is being modeled. The problem of reservoir cores being smaller than the representative elemental volume (REV) is a difficult one, which is more accentuated for fractured formations that have a higher REV. For fractured forma-tions, one is left with a narrow band of grid blocks, beyond which

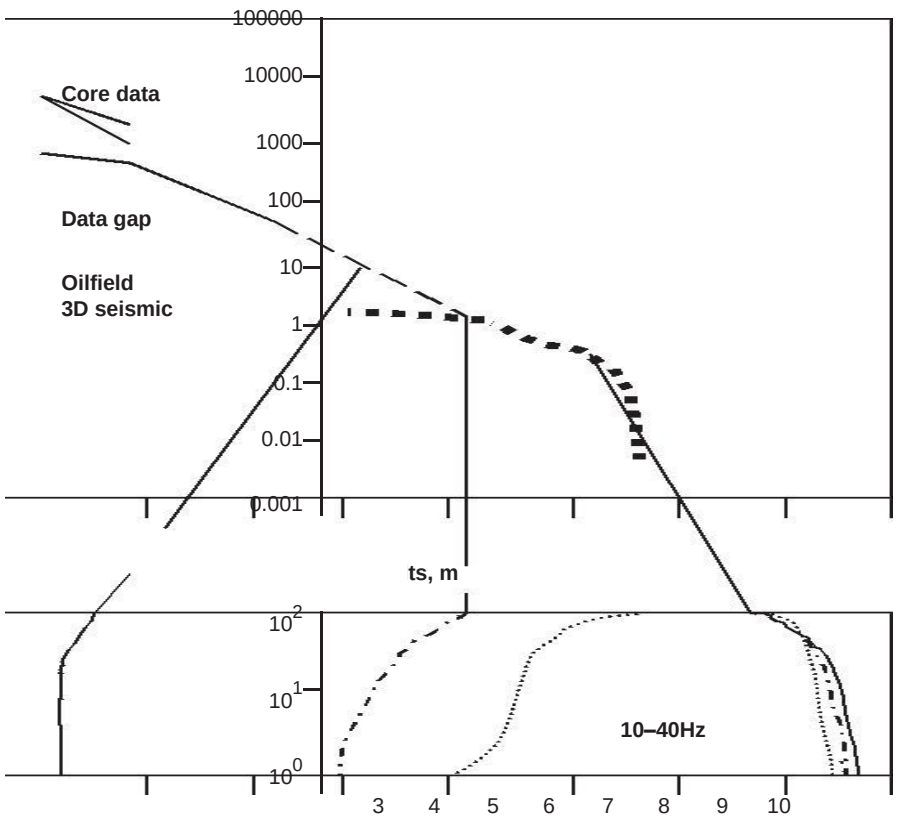

Figure 1 Data gap in geophysical modeling (after Islam, 2001).

solutions are either meaningless (large grid blocks) or unstable (too small grid blocks).

(ii)New Fluid Flow Equations

A porous medium can be defined as a multiphase material body (solid phase represented by solid grains of rock and void space rep-resented by the pores between solid grains) characterized by two main features: that a Representative Elementary Volume (REV) can be determined for it, such that no matter where it is

placed within a domain occupied by the porous medium, it will always contain both a persistent solid phase and a void space. The size of the REV is such that parameters that represent the distributions of the void space and the solid matrix within it are statistically meaningful.

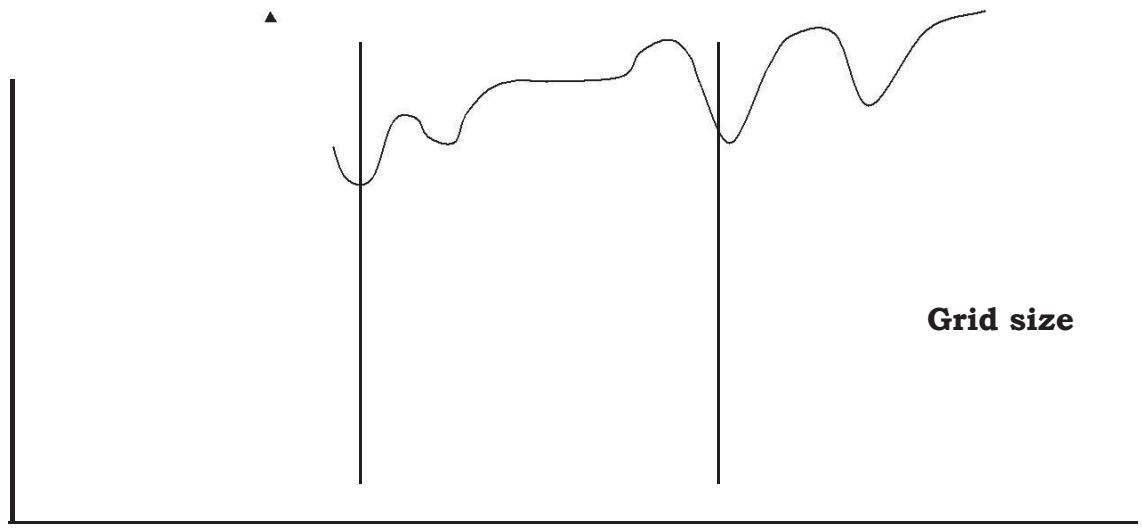

Figure 2 The problem with the finite difference approach has been the dependence on grid size and the loss of information due to scaling up (from Islam, 2002).

Theoretically, fluid flow in porous medium is understood as the flow of liquid or gas or both in a medium filled with small solid grains packed in homogeneous manner. The concept of hetero-geneous porous medium then introduced to indicate properties change (mainly porosity and permeability) within that same solid grains packed system. An average estimation of properties in that system is an obvious solution, and the case is still simple.

Incorporating fluid flow model with a dynamic rock model dur-ing the depletion process with a satisfactory degree of accuracy is still difficult to attain from currently used reservoir simulators. Most conventional reservoir simulators do not couple stress changes and rock deformations with reservoir pressure during the course of pro-duction and do not include the effect of change of reservoir tem-perature during thermal or steam injection recoveries. The physical impact of these geo-mechanical aspects of reservoir behavior is neither trivial nor negligible. Pore reduction and/or pore collapse leads to abrupt compaction of reservoir rock, which in turn cause miscalculations of ultimate recoveries, damage to permeability and reduction to flow rates and subsidence at the ground and well casings damage. In addition, there are many reported environmental impacts due to the withdrawal of fluids from underground reservoirs.

Using only Darcy's law to describe hydrocarbon fluid behavior in petroleum reservoirs when high gas flow rate is expected or when encountered in an highly fractured reservoir is totally misleading. Nguyen (1986) has showed that using standard Darcy flow analy-sis in some circumstances can over-predict the productivity by as much as 100 percent.

Fracture can be defined as any discontinuity in a solid material. In geological terms, a fracture is any planar or curvy-planar dis-continuity that has formed as a result of a process of brittle defor-mation in the earth's crust. Planes of weakness in rock respond to changing stresses in the earth's crust by fracturing in one or more different ways depending on the direction of the maximum stress and the rock type. A fracture can be said to consist of two rock sur-faces, with irregular shapes, which are more or less in contact with each other. The volume between the surfaces is the fracture void. The fracture void geometry is related in various ways to several fracture properties. Fluid movement in a fractured rock depends on discontinuities, at a variety of scales ranging from micro-cracks to faults (in length and width). Fundamentally, describing flow through fractured rock involves describing physical attributes of the fractures: fracture spacing, fracture area, fracture aperture and fracture orientation and whether these parameters allow percola-tion of fluid through the rock mass. Fracture parameters also influ-ence the anisotropy and heterogeneity of flow through fractured rock. Thus the conductivity of a rock mass depends on the entire network within the particular rock mass and is thus governed by the connectivity of the network and the conductivity of the single fracture. The total conductivity of a rock mass depends also on the contribution of matrix conductivity at the same time.

A fractured porous medium is defined as a portion of space in which the void space is composed of two parts: an interconnected network of fractures and blocks of porous medium, the entire space within the medium is occupied by one or more fluids. Such a domain can be treated as a single continuum, provided an appropriate REV can be found for it.

The fundamental question to be answered in modeling fracture flow is the validity of the governing equations used. The conven-tional approach involves the use of dual-porosity, dual perme-ability models for simulating flow through fractures. Choi et al (1997) demonstrated that the conventional use of Darcy's law in both fracture and matrix of the fractured system is not adequate. Instead, they proposed the use of the Forchheimer model in the fracture while maintaining Darcy's law in the matrix. Their work, however, was limited to single-phase flow. In future, the present status of this work can be extended to a multiphase system. It is anticipated that gas reservoirs will be suitable candidates for using Forchheimer extension of the momentum balance equation, rather than the conventional Darcy's law. Similar to what was done for the liquid system (Cheema and Islam, 1995); opportunities exist in con-ducting experiments with gas as well as multiphase fluids in order to validate the numerical models. It may be noted that in recent years several dual-porosity, dual-permeability models have been proposed based on experimental observations (Tidwell and Robert, 1995; Saghir et al, 2001).

(iii)Coupled Fluid Flow and Geo-mechanical Stress Model

Coupling different flow equations has always been a challenge in reservoir simulators. In this context, Pedrosa et al (1986) introduced the framework of hybrid grid modeling. Even though this work was related to coupling cylindrical and Cartesian grid blocks, it was used as a basis for coupling various fluid flow models (Islam and Chakma, 1990; Islam, 1990). Coupling flow equations in order to describe fluid flow in a setting, for which both pipe flow and porous media flow prevail continues to be a challenge (Mustafiz et al, 2005).

Geomechanical stresses are very important in production schemes. However, due to strong seepage flow, disintegration of formation occurs and sand is carried towards the well opening. The most common practice to prevent accumulation as followed by the industry is to take filter measures, such as liners and gravel packs. Generally, such measures are very expensive to use and often, due to plugging of the liners, the cost increases to maintain the same level of production. In recent years, there have been studies in vari-ous categories of well completion including modeling of coupled fluid flow and mechanical deformation of medium (Vaziri et al, 2002). Vaziri et al (2002) used a finite element analysis developing a modified form of the Mohr–Coulomb failure envelope to simulate both tensile and shear-induced failure around deep wellbores in oil and gas reservoirs. The coupled model was useful in predicting the onset and quantity of sanding. Nouri et al (2006) highlighted

In the experimental part of it in addition to a numerical analysis and measured the severity of sanding in terms of rate and duration. It should be noted that these studies (Nouri et al, 2002; Vaziri et al, 2002 and Nouri et al, 2006) took into account the elasto-plastic stress-strain relationship with strain softening to capture sand pro-duction in a more realistic manner. Although, at present these stud-ies lack validation with field data, they offer significant insight into the mechanism of sanding and have potential in smart-designing of well-completions and operational conditions.

Recently, Settari et al (2006) applied numerical techniques to cal-culate subsidence induced by gas production in the North Adriatic. Due to the complexity of the reservoir and compaction mechanisms, Settari (2006) took a combined approach of reservoir and geo-mechanical simulators in modeling subsidence. As well, an extensive validation of the modeling techniques was undertaken, including the level of coupling between the fluid flow and geo-mechanical solution. The researchers found that a fully coupled solution had an impact only on the aquifer area, and an explicitly coupled technique was good enough to give accurate results. On grid issues, the pre-ferred approach was to use compatible grids in the reservoir domain and to extend that mesh to geo-mechanical modeling. However, it was also noted that the grids generated for reservoir simulation are often not suitable for coupled models and require modification.

In fields, on several instances, subsidence delay has been noticed and related to over consolidation, which is also termed as the threshold effect (Merle et al, 1976; Hettema et al, 2002). Settari et al (2006) used the numerical modeling techniques to explore the

effects of small levels of over-consolidation in one of their studied fields on the onset of subsidence and the areal extent of the result-ing subsidence bowl. The same framework that Settari et al (2006) used can be introduced in coupling the multiphase, compositional simulator and the geo-mechanical simulator in future.

(iv)Fluid Flow Modeling Under Thermal Stress

The temperature changes in the rock can induce thermo-elastic stresses (Hojka et al, 1993), which can either create new fractures or can alter the shapes of existing fractu res, changing the nature of the primary mode of production. It can be noted that the thermal stress occurs as a result of the difference in temperature between injected fluids and reservoir fluids or due to the Joule Thompson effect. However, in the study with unconsolidated sand, the thermal stresses are reported to be negligible in comparison to the mechani-cal stresses (Chalaturnyk and Scott, 1995). A similar trend is notice-able in the work by Chen et al (1995), which also ignored the effect of thermal stresses, even though a simultaneous modeling of fluid flow and geomechanics is proposed.

Most of the past research has been focused only on thermal recovery of heavy oil. Modeling subsidence under thermal recov-ery technique (Tortike and Farouq Ali, 1987) was one of the early attempts that considered both thermal and mechanical stresses in their formulation. There are only few investigations that attempted to capture the onset and propagation of fractures under thermal stress. Recently, Zekri et al (2006) investigated the effects of ther-mal shock on fractured core permeability of carbonate formations of UAE reservoirs by conducting a series of experiments. Also, the stress-strain relationship due to thermal shocks was noted. Apart from experimental observations, there is also the scope to perform numerical simulations to determine the impact of thermal stress in various categories, such as water injection, gas injection/produc-tion etc. More recently, Hossain et al (2009) showed that new math-ematical models must be introduced in order to include thermal effects combined with fluid memory.